New Zealand Petroleum Reserves

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August 2010

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About this document

Purpose

This report responds to two Ministerial directives arising from the electricity market review and the Government's Action Plan to maximise the gains from New Zealand's petroleum resources. Respectively, these directives are to:

1. report on measures to improve the quality of published information on gas reserves; and
2. improve the quality of information provided by industry to Government of the Crown's petroleum resources.

The purpose of this report is to seek feedback on the proposed options to improve the quality of information provided by industry and published by Government of the Crown's petroleum resources.

How to have your say

There are questions in each part of this document that may help you formulate your feedback. You are also welcome to make other comments. The questions are listed in a feedback form at the end of this document. You don't have to use the feedback form, or comment on all the questions, but please make sure it's clear which part of the document you are commenting on.

Submissions close at 5pm Friday 10 September 2010.

You can give us feedback in several ways.

Online

Provide your comments online through the consultation section on our website www.med.govt.nz.

Email

Send your comments to us at petroleumreserves@med.govt.nz

Fax

Put "New Zealand Petroleum Reserves Review" in the subject line and fax to (04) 473 7010

Post or courier

Fuels & Crown Resources Group, Energy & Communications Branch
Ministry of Economic Development
33 Bowen Street
PO Box 1473
Wellington 6140

Further enquiries

Use the addresses above to contact us for any further information you may require.

What happens with your feedback?

We will consider all submissions we receive as final proposals are developed for Government consideration.

A summary of submissions will be made public at the time the Government announces its decisions.

All written responses will be public information. Responses may be the subject of requests under the Official Information Act 1982 (**OIA**). The OIA specifies that information is to be made available to requesters unless there are sufficient grounds for withholding it. While we will take into account any specific request you make for us to keep information confidential, we cannot guarantee that information you provide us with will not be made public. Any decision to withhold information requested under the OIA is reviewable by the Ombudsman.

Petroleum reserves in New Zealand

Why petroleum reserve information is important

Domestic oil and gas production accounted for over 40% of total domestic primary energy production in 2009 providing direct royalty and taxes of approximately $1 billion. Current and forecast movements in oil and gas reserve/resource estimates are the first and most important factor(s) in all forecasts of future oil and gas availability and supply. It is important to the Crown as owner and manager of the Crown's petroleum estate, which in turn has important royalty and taxation implications. Moreover, reserves data has a major bearing on broader energy policy decisions, whether they are direct Government measures to support and promote the upstream petroleum sector, Government previsions for future electricity prices and emissions liabilities or electricity grid investment planning.

Given the absence of any current international supply links, New Zealand's future gas supply outlook has a particular importance. Gas is a critical fuel for electricity generation, petrochemical production and a range of industrial, commercial and residential users in New Zealand. It currently supplies approximately one fifth of total electricity generation and it has a major influence on both short-run costs and the cost of new capacity. It plays a vital role in backing up renewable generation, particularly hydro and wind, and it is a premium fuel, providing flexibility for short-notice generation and lower emissions than other thermal fuels.

For industrial gas users, reserve and resource data is an essential part of investment decisions, whether they are decisions to build additional gas-fired power generation for an electricity generator or decisions on what fuel to use for industrial, commercial and residential users. Forecasts of future gas availability and supply therefore have a direct impact on price and a range of commercial and public policy decisions.

An overview of New Zealand's oil and gas reserves position is provided in Appendix 2.

Overview of reserves classifications systems

There are several reserves classification systems used around the world. The most widely used classification system and the industry benchmark standard is the Petroleum Resources Management System[1] (**PRMS**). The PRMS is co-sponsored by the Society of Petroleum Engineers (**SPE**), the American Association of Petroleum Geologists (**AAPG**), the World Petroleum Council (**WPC**) and the Society of Petroleum Evaluation Engineers (**SPEE**). The PRMS was published in 2007 and is supported by the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources". Those companies listed in the United States may also undertake reserves estimates according to the United States Securities and Exchange Commission (**SEC**) requirements[2]. SEC requirements relate specifically to so-called "P90"[3] or proved reserves and have tended to be more stringent than the PRMS requirements. Following new SEC guidelines adopted from 1 January 2010, the SEC is now more closely aligned with the PRMS.

[1] http://www.spe.org/industry/reserves/docs/Petroleum_Resources_Management_System_2007.pdf

[2] http://www.law.uc.edu/CCL/regS-X/SX4-10.html and http://www.law.uc.edu/CCL/regS-K/SK102.html

[3] *"P90" reserves, also referred to as "proved reserves" or "1P reserves", are those reserves claimed to have a reasonable certainty (ie at least 90%) of being recoverable under existing economic, operating and regulatory conditions..*

Other reserve classification systems include:

- the United Nations Framework Classification[4];
- the United Kingdom Statement of Recommended Practices[5];
- the Canadian Security Administrators[6];
- the Russian Ministry of Natural Resources[7];
- the Norwegian Petroleum Directorate[8]; and
- Chinese Petroleum Reserves Office[9].

In New Zealand, all permit holders are required to report their petroleum reserves[10] under good oil field practice. In the case of reserve reporting, MED understands that this means the PRMS. Officials understand that there have been no major discrepancies between the P90 reserves reported in the half-yearly reports under PRMS guidelines and the P90 reserves derived under SEC guidelines. Any discrepancies that do occur are likely to reduce further in coming years following the new guidelines adopted by the SEC from 1 January 2010.

For ease of reference, the Petroleum Resources Management System has been substantially copied in Appendix 3.

Q1: Can upstream producers confirm that the reserves information reported to Crown Minerals is derived using the Petroleum Resources Management System?

Status quo

All reserves figures are collected in six-monthly activity reports provided by mining permit holders to Crown Minerals. Regulatory powers for the collection of this information are drawn from section 90A of the Crown Minerals Act 1991 and regulation 39 of the Crown Minerals (Petroleum) Regulations 2007. All permit holders are required to provide P90[11] and P50[12] reserves[13], ultimately recoverable oil and gas, remaining petroleum and gas in place and an explanation of the methodology used to calculate the estimates. Penalties for non-compliance are set in section 101(2) of the Crown Minerals Act and amount to a fine not exceeding $10,000, and, if the offence is a continuing one, to a further fine not exceeding $1,000 for every day or part of a day during which the offence continues (more detailed information on the legislative and reporting framework is provided in Appendix 4).

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[4] http://www.unece.org/energy/se/pdfs/UNFC/unfc2009/unfc2009_report_e.pdf

[5] http://www.oiac.co.uk/docs/SORP%20July%202001.doc

[6] http://www.albertasecurities.com/securitiesLaw/Regulatory%20Instruments/5/2232/COGEHs.5DefinitionsofOilandGasResourcesandReserves.pdf

[7] http://capcp.psu.edu/RussianData/data/classification.pdf

[8] http://www.npd.no/Global/Engelsk/5%20-%20Rules%20and%20regulations/Guidelines/Ressursklassifisering_e.pdf

[9] http://www.ccop.or.th/PPM/document/CHWS2/CHWS2DOC04.pdf

[10] *See regulation 39 of the Crown Minerals (Petroleum) Regulations 2007.*

[11] *Supra, n.3*

[12] *"P50" reserves, also referred to as "probable reserves" or "2P reserves", are those reserves claimed to have at least a 50% certainty of being produced.*

[13] *Supra n.10*

There is no specific mention in the Crown Minerals Act or the Crown Minerals (Petroleum) Regulations 2007 of which classification system must be used. Paragraph 6.2 of the Minerals Programme for Petroleum (2005) relates to good exploration and mining practice and includes a requirement that there be ongoing definition of the hydrocarbon accumulation in terms of volumes in place, recoverable reserves and producibility parameters.

It is understood that the Petroleum Resources Management System is what is meant by good oil field practice when it comes to reserves reporting.

Crown Minerals collates the reserves data from these half-yearly reports, cross-check the figures with producers and then forward the numbers to the Energy Information and Modelling Team in the Energy & Communications Branch of the Ministry of Economic Development (**MED**), which then publish ultimate recoverable and P50 oil and gas reserve data annually in the Energy Data File. The 2010 edition of the Energy Data File included P90 reserves for the first time.

Q2: Has the status quo legislative and reporting regime been accurately described?

Problems/issues with the current reporting and disclosure regime

Key problems with the current reporting and disclosure regime include:

1. There is a perceived lack of confidence in the accuracy, precision and consistency of reserve information currently reported by industry and published by MED.

2. The quality and quantity of petroleum reserve data is not sufficient to allow MED to independently verify and validate reserves estimates. This in turn negatively impacts MED's ability to optimally manage the Crown's petroleum estate.

3. Neither MED or industry stakeholders have any visibility of the upside potential at existing fields. Confusion arises where prominent market participants express views on future gas supplies which are far more bullish than what is supported by published P50 reserve data[14].

4. Industry stakeholders also historically had no visibility of the downside risks at existing fields as only P50 reserve estimates have been published. MED changed this in 2010 with the publication of P90 reserves in the Energy Data File.

Lack of confidence in reported reserves

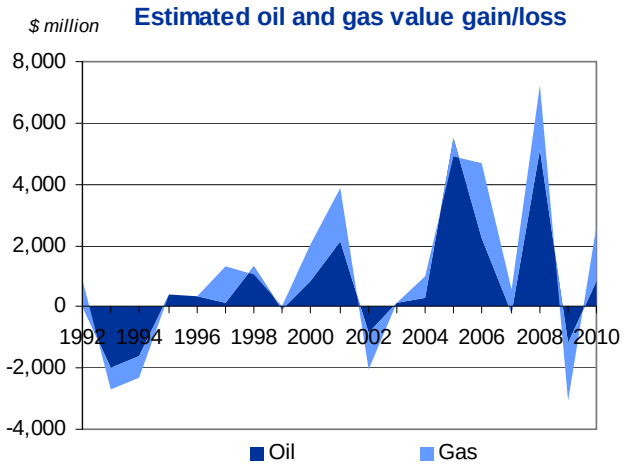
Confidence in reserve information reported by industry and published by MED has become a source of concern as annual reported reserves have fluctuated substantially from one year to the next. In 2010 there was a net oil reserves increase of 6% (9.2 million barrels) and a net increase in gas reserves of 14% (260 PJs). In 2009 there was a net oil reserves decline of 7% (13.8 million barrels) while gas reserves declined 12% (270 PJs), while in 2008 net oil reserves increased by 21% (38.3 million barrels), while gas reserves increased 20% (406 PJs) from the previous year.

[14] *For example, in December 2007 Todd Energy reported that it saw potentially 2,000 PJs of new gas at Mangahewa, Pohokura, Kapuni and Karewa* http://www.crownminerals.govt.nz/cms/news/2007/todd-makes-substantial-gas-discovery-at-mangahewa.

Substantial swings in reported oil and gas reserves also occurred in 1997 (gas), 1998 (oil), 2000 (oil and gas), 2001 (oil and gas), 2002 (oil and gas), 2005 (oil) and 2006 (oil and gas). There is no concern where reserve increases occur as a result of new field discoveries being booked (like Pohokura in 2001 and Maari and Tui in 2005 and Kowhai in 2010). Concerns do arise, however, where substantial revisions occur at existing producing fields from one year to the next.

The volatility in reported oil reserves has a direct impact in the Crown's assessment of future royalty and taxation revenue, while the volatility in reported gas reserves, combined with an already tight supply/demand outlook, has a direct impact on gas and electricity prices. It increases perceived commercial risks for generators and reduces the prospects for future gas-fired power generation, which in turn is likely to lead to higher long term electricity prices as prices trend upward to the long run marginal cost of renewable generation.

Applying an average New Zealand export crude price provides an approximate monetary value for oil reserve fluctuations and shows reserves additions of up to $5.5 billion and downward losses of up to $2 billion from one year to the next. On the gas side, applying a wholesale price provides an approximate monetary value of gas reserve fluctuations and shows reserves additions of up to $2.4 billion and downward losses of up to $1.9 billion from one year to the next. When combined, New Zealand's oil and gas reserves have risen by up to $7.2 billion in 2008 or have been revised downward by $3 billion in 2009.



There are a number of reasons that may explain why confidence has been eroded:

1. Lack of resources, capability and/or prioritisation within Crown Minerals to make the most of existing legislative and regulatory powers to verify and validate reserves estimates. A case in point is the application for a mining permit where companies are required under the regulations to provide a reservoir model or models (section 19(2)(e)(ii)). Typically this is provided in the form of a report as Crown Minerals has neither the software necessary to run these reservoir models nor the staff with the necessary expertise to run them even if they were provided.

   Another example is the calculated and measured daily and monthly production rates for oil, condensate, gas and water per well. This information is collected as part of the half-yearly mining permit reports but is not incorporated into any spreadsheet or used by anyone in the Ministry to understand the reservoir performance at particular fields.

2. Inconsistent reporting against regulatory requirements and lack of engagement by upstream industry participants. The quality and quantity of petroleum reserve data supplied to MED is not sufficient for MED to independently verify reserves estimates even if it did have the resources and capability at its disposal. When Crown Minerals do seek clarification from upstream participants on reserves estimates, the responses tend to be minimal. From time to time substantial revisions have occurred in the cross-checking

process between the numbers submitted by producers in their half-yearly reports and those agreed to by producers for publication in the Energy Data File. In 2008, for example, P50 reserves at Maui were initially reported as 361 PJs, while those published in the Energy Data File were 490 PJs. The inconsistent reporting and lack of engagement by upstream industry participants may in turn be explained by the following factors:

a. the commercial sensitivity the companies place on this reserves information;

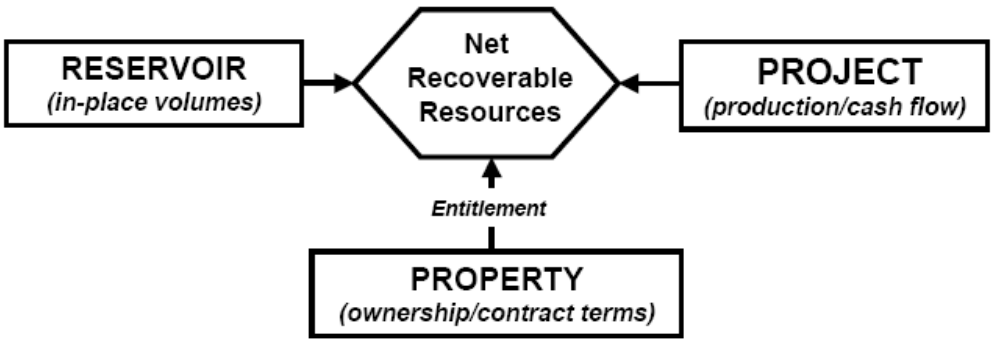
b. the lack of any regulatory requirement for upstream industry participants to engage in the cross-checking process; and

c. weak penalties for non-compliance.

3. Apparent discrepancies and/or inconsistencies in the methodologies used to derive reserves estimates between companies. Concerns arise where companies have acquired assets in New Zealand and have reported significantly different reserve numbers to those reported by the previous permit holders of those fields. A case in point was the acquisition of Swift Energy's assets by Origin Energy in 2008, with Origin Energy subsequently reporting substantially lower oil and gas reserve estimates for the Rimu and Tariki/Ahuroa fields than those previously reported by Swift Energy.

Insufficient information to independently verify and validate reserves estimates

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.



Existing legislative and regulatory provisions are focused on reservoir properties but provide little or no requirement on companies to report the project or property parts of the resource evaluation equation. Even with regards the reservoir part of the equation, the existing regulations are focused on the results of calculations and an explanation of the methodology used but not the calculations themselves. It is this part that provides the ability to cross-check the reservoir estimates.

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. At present, MED has no visibility over a range of parameters essential in deriving these cash flow projections. In particular, there is no regulatory requirement to report:

1. the estimated costs associated with the project to develop, recover, and produce the quantities of production at its Reference Point, including environmental, abandonment, and reclamation costs charged to the project, based on the evaluator's view of the costs expected to apply in future periods. This information is required for all new applications for mining permits but does not apply to those fields already in production;

2. the estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods including that portion of the costs and revenues accruing to the entity; and/or

3. the discount rate used.

No visibility of upside potential at existing fields

There is currently no regulatory requirement to report upside potential (P10 or contingent resources) at existing fields. While it would be imprudent to base public policy or commercial decisions on anything more than P50 reserves, an understanding of the upside potential and the factors that would contribute to reclassifying P10 or contingent resources into P50 reserves is an essential part of understanding and managing the Crown's petroleum estate. For industry stakeholders, the absence of any visibility of the upside potential creates confusion when prominent upstream participants express views on future oil and gas supplies which are far more bullish than what is supported by the published P50 reserve data[15].

Historically no visibility of downside risks at existing fields for industry stakeholders

While P50 reserves estimates are generally the most widely used reserves estimates for public policy and commercial decisions, P90 reserves are also widely used internationally as a benchmark reserve. This is particularly so in the United States and in long-term liquefied natural gas contracts. MED has historically only published P50 reserves. As a result of this review MED published P90 oil and gas reserves in the Energy Data File for the first time in 2010.

Q3:	**Have the problems/issues with the existing legislative and reporting regime been adequately described?**
Q4:	**Are there any additional problems/issues which have not been identified?**

Objectives

This report seeks to provide solutions to three principal objectives:

1. **Ensuring a reasonable degree of consistency in estimation methodologies between fields and companies**: There should be reasonable consistency in the methodology and standards applied to derive reserve data following established industry best practice.

2. **Improving the accuracy and precision of reported reserves:** By their very nature, reserve numbers are somewhat imprecise due to the inherent uncertainties in, and the

[15] *For example, in December 2007 Todd Energy reported that it saw potentially 2,000 PJs of new gas at Mangahewa, Pohokura, Kapuni and Karewa http://www.crownminerals.govt.nz/cms/news/2007/todd-makes-substantial-gas-discovery-at-mangahewa.*

limited nature of, the accumulation and interpretation of data upon which the estimating of reserves information is predicated. Moreover, the methods and data used in estimated reserves information are often necessarily indirect and analogical in character rather than direct or deductive. However, a reasonable degree of confidence is required in order to base future commercial and public policy decisions.

3. **Widening the spectrum of reported reserves such that all stakeholders have a view of both the upside and downside potential at existing fields and can manage their risk accordingly**.

Q5: Do you have any comments on the proposed objectives?

International comparisons

In order to identify options that can provide solutions to the three objectives identified above, a comparison of reserve reporting requirements and reserve information publicly available has been undertaken for Australia, Norway, the United States, and the United Kingdom. The United States is the most conservative jurisdiction in terms of reserves reporting requirements, with only proved reserves and production reported and published by the Energy Information Agency. The United States Geological Survey conducts its own assessments for prospective resources and publishes the results periodically.

International reserves reporting requirements

	Information required to be reported								
					Reserves				
Country	STOIIP[1]	GIIP[2]	Estimated recoverable oil and gas	Cumulative recovery	P90	P50	P10	Contingent resources	Prospective resources
New Zealand	Yes	Yes	Yes	Yes[3]	Yes	Yes	No	No	No
United States	No	No	No	Yes	Yes	No	No	No	No
Norway	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
United Kingdom	Yes	Yes	Yes	Yes[4]	Yes	Yes	Yes	Partially[5]	Partially[5]
Australia	Yes	Yes	Yes	Yes[6]	Yes	Yes	No	Yes	No[7]
	Information publicly available								
					Reserves				
Country	STOIIP[1]	GIIP[2]	Estimated recoverable oil and gas	Cumulative recovery	P90	P50	P10	Contingent resources	Prospective resources
New Zealand	No	No	Yes	Yes[3]	No	Yes	No	No	No
United States	No	No	No	Yes	Yes	No	No	No	Yes
Norway	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
United Kingdom	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Australia	No	No	Yes[8]	Yes	No	Yes	No	Yes	Yes

1. Stock Tank Oil Initially In Place

2. Gas Initially In Place

3. This can be derived from production data published in the Energy Data File

4. DECC derives this information from information provided

5. Information is gained from a mixture of company information reported to DECC and internal DECC modelling

6. This can be derived from production data provided.

7. Australin authorities come to their own view of prospective resources

8. This can be derived from production data provided.

Australia has similar reporting requirements to New Zealand, although it also collects contingent resource estimates and cost information from companies. Australia does not publish P10 reserve data but instead publishes estimates of contingent resources by basin and prospective resources.

The United Kingdom and Norway have the most all-encompassing reporting requirements, with both countries sending out standardised Excel templates for companies to fill in a broad range of reserve, projected production and investment information on an annual basis. The United Kingdom collects some information on contingent and prospective resources from companies and supplements this with its own in-house assessments. Both the United Kingdom and Norway publish the full spectrum of reserves and resources by basin, alongside information around estimated recoverable reserves and cumulative recovery to date. Norway also publishes information on hydrocarbons initially in place per basin.

In comparison, New Zealand appears to be more at the light-handed end of international best practice, particularly with regards to information publically available. All countries reviewed, with the exception of New Zealand, publish some information on upside potential, while the United States, Norway and the United Kingdom also publish P90 reserves. The review of international best practice regimes also revealed that more information is collected by Government agencies which, in turn, apply significantly more resources to evaluating and assessing their countries' petroleum estate.

A more detailed review of international legislative and reporting regimes for petroleum reserves is provided in Appendix 4.

Q6: Do you have any comments on the review of international reserves reporting regimes?

Options to improve reserve information quality and disclosure

In order to respond to the specific objectives of this report three options are put forward for consideration:

Option 1 – more resources but no regulatory change

Existing regulatory powers oblige companies to report to Crown Minerals reasonably extensive information on resources and reserves either at the exploration phase, at the application for a mining permit or during ongoing mining activities (see Appendix 3 for full details). Not all of the information stipulated in regulations is reported consistently to Crown Minerals and where it is Crown Minerals is not sufficiently resourced or staffed to properly analyse the information to come to an independent assessment.

This option would involve the following:

1. Increase resourcing of Crown Minerals to allow for improved validation and use of existing reported data. This could involve one of the following steps:

    a. A combination of increased internal validation in Crown Minerals combined with the occasional use of an external petroleum reservoir engineer to cross-check material changes in large fields. This could be a short-term option and would cost approximately $80,000 per year depending on the amount of work required by the external consultant;

b. A combination of increased internal validation in Crown Minerals combined with more extensive use of GNS Sciences Ltd (**GNS**) to cross-check material changes in reported reserves. GNS would need to increase its own internal capacity to fill this role, notably via the employment of a petroleum reservoir engineer and/or a petro physicist. This could be a medium-term option costing between $200,000 to $300,000 per annum per specialist across Crown Minerals and GNS and up to $100,000 for the necessary software (i.e. a total cost of $600,000 to $700,000 for two people plus software). The advantage of using GNS over Crown Minerals (see long-term option below) is that any new employee at GNS could tap into a much wider and deeper pool of technical expertise across the organisation than that currently available in Crown Minerals. The disadvantage of GNS over Crown Minerals is that perceptions of conflicts of interest will arise within industry given the large amount of consulting work GNS undertakes on behalf of industry; or

c. A long-term commitment to increase the resources and capability of Crown Minerals such that Crown Minerals can conduct its own validation of reservoir models and prospects. This would require the creation of a core team with specialist expertise within the Petroleum Team of Crown Minerals, alongside the necessary software. This would be a long-term option with costs at least as high as the "GNS option" cited above.

2. Using the full extent of the regulatory disclosure provisions to publish P90 reserve data, forecast production profiles by field and resource estimates (including the range of uncertainties) from discoveries or appraisals under any exploration permit, mining permit, or existing privilege.

Depending on which level of additional resources were provided to MED, this option would result in a progressively more robust understanding of existing reserves.

This option places no additional compliance costs on companies but still provides other stakeholders with significantly more relevant data than that currently publicly disclosed. The major downside to this option is that it provides no view on the potential upside at existing discoveries and would do little to dispel confusion between market participants as to the future outlook of gas supply. Moreover, this option does not provide for additional information necessary for any reservoir engineer or reservoir modeller to validate reported reserves and there are no enforcement mechanisms available to ensure that companies actively engage during the cross-checking process. There is the risk that the full benefit of providing additional resources to Crown Minerals in this area may not be captured if there is no regulatory change to ensure that this information is made available.

Q7: Do you have any comments on Option 1, particularly around where additional resources would be best applied (external consultants, GNS Sciences Ltd or MED)?

Option 2 – UK model

Option 2 encompasses all of Option 1 but extends the information reporting requirements to include P10 reserves and P90/50/10 for contingent resources along with development price/cost thresholds for the latter (i.e. why is it contingent?).

Option 2 would see the standardisation of reserve reporting via a template sent to companies and follow up cross checks, similar to the process currently undertaken in the United Kingdom. The template could take different forms (simple template completed offline and submitted to Crown – e.g. Excel, an online reporting tool, or an enterprise scale production data management).

Reserve and resource estimates are by their very nature somewhat imprecise. Existing regulations are currently silent on what happens should material disagreements exist between potential reserve and resource estimates provided by companies and those thought reasonable by Crown Minerals. Crown Minerals can request clarifications from companies but there is no legal requirement on companies to engage or to provide additional information to support their reserve estimates. Accordingly, Option 2 includes changing existing regulatory powers to:

1. Require companies to provide any information and supporting material reasonably requested by Crown Minerals to support and validate reserve, resource and production profile estimates;

2. Place more severe penalties on companies for non-compliance. At present, penalties for non-disclosure of reserves are capped at $10,000 and, if the offence is a continuing one, to a further fine not exceeding $1,000 for every day or part of a day during which the offence continues. By way of comparison, the penalty for non-compliance with the Gas (Information Disclosure) Regulations 1997 is a fine not exceeding $200,000 for a summary conviction and to a further $10,000 for every day or part of a day during which the offence is continued (section 57(3) of the Gas Act 1992). It is recommended to increase the maximum penalty for non-compliance of reporting petroleum reserves and the follow up cross-checking process to an equivalent level; and

3. Allow the disclosure of P10 reserve figures by field and contingent resources by basin.

This option would place some additional compliance costs on industry although it is arguable that these additional costs are minimal as companies already have this information readily at hand and use it to derive the reserve estimates they report to Crown Minerals. It is estimated that these additional compliance costs would be no more than $20,000 per company per year (e.g. 10 days for one externally contracted person). For the five companies that supply almost all gas to market, this would amount to a total maximum additional annual cost of $100,000 (i.e. a total cost of $700,000 to $800,000 when combined with Option 1)

Option 2 would involve legislative and regulatory changes. It is logical that these changes should be incorporated into the broader review of the Crown Minerals Act and associated regulatory settings around petroleum. The current timeline is for a discussion paper to be released for public consultation in 3Q 2010.

This option would significantly boost confidence in reported reserves figures as Crown Minerals would have all the information necessary to validate and cross check the reported reserves figures. This option would also benefit a wider pool of stakeholders and improve investment decisions by publicly disclosing both the downside and the upside potential at existing discoveries. It is the Ministry's preferred option of the three options described.

Q8: Do you have any comments on the extent to which Option 2 would meet the stated objectives?

Option 3 – Norwegian model

Option 3 is broader than Option 2 in that it is aimed at allowing Crown Minerals, or its appointed service providers, to come to a full independent assessment of reserves estimates. Option 3 encompasses all of Option 2 but further extends the reporting requirements to include:

1. Full reserves documentation including supporting calculation interpretations, data and performance models for all wells and fields under appraisal;

2. All raw and interpreted data for all wells and fields;

3. All internal performance, volume and reserve related documentation.

This option is akin to the Norwegian model and would provide the most complete information of the Crown's hydrocarbon resource. It is also the most costly option and would impose the highest compliance costs on industry. It is estimated that this would cost between $200,000 to $400,000 per annum per medium to large sized field (less for smaller fields where there is less data), equating to one to two people working 3-6 months at most. This would mean a total additional annual cost of this option of approximately $3 million (i.e. a total cost of $3.6 million to $3.7 million when combined with Option 2).

Given the relative size of New Zealand's reserves and production to those of Norway, it could be argued that this option is out of proportion to the country's current requirements and it is likely to be seen as too intrusive by industry.

Q9: Do you have any comments on the extent to which Option 3 would meet the stated objectives?

Resource validation and verification options

	Resources	Direct costs to Crown per year ($ 1,000)	Indirect costs to industry per year ($1,000)	Regulatory changes	Advantages	Disadvantages
Option 1 - more resources but no regulatory change						
- sub-option 1	One contractor	80	0	None	a) Cheapest option b) No additional compliance costs to industry	a) Limited ability to verify and validate data b) Principal-agent problems c) No visibility of upside potential
- sub-option 2	Two specialis staff at GNS Sciences Ltd plus software	600-700	0	None	a) Able to tap into a wider pool of technical expertise than that available in Crown Minerals b) No additional compliance costs to industry	a) Conflicts of interests b) Principal-agent problems c) No visibility of upside potential d) Limited ability
- sub-option 3	Two specialist staff at Crown Minerals plus software	600-700	0	None	a) Expertise kept in-house - no principal-agent problems as with GNS b) No additional compliance costs to industry	a) Limited ability to verify and validate data b) Principal-agent problems c) No visibility of upside potential
Option 2 - UK model (preferred)						
	Two specialist staff at Crown Minerals plus software	600-700	100	a) Reporting requirements extended to include: i) P10 reserves ii) P90/50/10 contingent resources with development/cost thresholds b) Increased enforcement measures: i) Requirement to provide supporting information reasonably requested ii) Increase penalties for non-compliance c) Increase publication of reserves: i) P90/50/10 reserves by field ii) contingent resources by basin	a) provides visibility to all stakeholders of upside and downside potential b) Allows for verification and validation of data c) provides confidence in accuracy, precision and consistency of data	a) Imposes additional compliance costs on industry b) Likely to be perceived as intrusive by upstream participants
Option 3 - Norwegian model						
	Two specialist staff at Crown Minerals plus software	600-700	3,000	a) All regulatory changes in Option 2 plus the extension of reporting requirements to include: i) Full reserves documentation including supporting calculation interpretations, data and performance models for all fields and fields under Appraisal ii) All raw and interpreted data for all wells and fields iii) All internal performance, volume and reserve related documentation	a) Provides the most complete information of the Crown's hydrocarbon resource	a) By far the most costly option b) Likely to be seen as too intrusive by upstream participants

Analysis of options

At this stage, MED's preferred option is Option 2, with MED the preferred organisation to receive additional resources. Option 2 meets the specific objectives of improving the accuracy and precision of reported reserves, ensuring consistency between fields and operators, and improving security of supply by extending the breadth and depth of reporting. Allocating additional resources to MED avoids the potential conflicts of interest and principal-agent problems associated with GNS Sciences Ltd, while the estimated costs of $700,000 to $800,000 need to be compared to the size of recent reserve fluctuations of plus $7 billion or minus $3 billion. Option 2 is considered the least cost option to meet the objectives set by this report.

Option 1 provides no view on the potential upside at existing discoveries. It does not provide any enforcement mechanisms to ensure compliance by companies and/or active engagement during the cross-checking process and it would do little to dispel confusion between market participants as to the future outlook of gas supply. Moreover, this option does not provide for additional information necessary for any reservoir engineer or reservoir modeller to validate reported reserves. There is the risk that the full benefit of providing additional resources to MED in this area may not be captured if there is no regulatory change to ensure that this information is made available. Option 1 would therefore not meet the specific objectives set for this review.

Option 3, meanwhile, would provide a further level of accuracy, precision, consistency, and breadth and depth of understanding to Option 2 but comes at a much greater cost and it is likely to be considered out of proportion to the country's current requirements and it is likely to be seen as too intrusive by industry. This may, nevertheless, be an option for the longer term.

Q10: Do you agree/disagree and/or have any comments on the analysis of options undertaken?

Next steps

All options involve at least some increase in resources for MED. The funding considerations are separate to the considerations of which organisation (GNS or MED) should receive additional funding which are the subject of consultation.

Options 2 and 3 involve legislative and regulatory changes. Should one of these options be pursued, it is logical that these changes should be incorporated into the broader review of the Crown Minerals Act taking place in 2010 and associated regulatory settings around petroleum taking place in 2010 and 2011.

We welcome feedback from stakeholders on these options and ask that submissions are received by 10 September 2010.■

Appendix 1: Format for submissions

To assist MED in the orderly consideration of stakeholders' responses, a suggested format for submissions has been prepared. This is drawn from the questions posed throughout the body of the consultation document.

Respondents are also free to include other material in their responses.

Q1:	Can upstream producers confirm that the reserves information reported to Crown Minerals are derived using the Petroleum Resources Management System?
Q2:	Has the status quo legislative and reporting regime been accurately described?
Q3:	Have the problems/issues with the existing legislative and reporting regime been adequately described?
Q4:	Are there any additional problems/issues which have not been identified?
Q5:	Do you have any comments on the proposed objectives?
Q6:	Do you have any comments on the review of international reserves reporting regimes?
Q7:	Do you have any comments on Option 1, particularly around where additional resources would be best applied (external consultants, GNS Sciences Ltd or MED)?
Q8:	Do you have any comments on the extent to which Option 2 would meet the stated objectives?
Q9:	Do you have any comments on the extent to which Option 3 would meet the stated objectives?
Q10:	Do you agree/disagree and/or have any comments on the analysis of options undertaken?

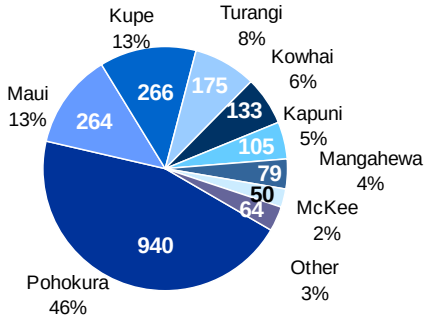
Appendix 2: Petroleum Reserves in New Zealand

Current status of reported oil and gas reserves

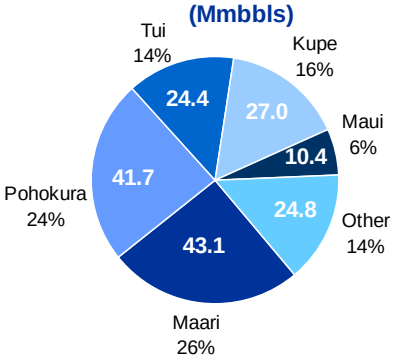
The former Ministry of Commerce started regularly collecting and reporting New Zealand's petroleum reserves from 1997, with 1 January 1996 the first published reporting period. Prior to 1996 data collection was sporadic, with data published in alternate years in the Ministry of Commerce's Supply and Demand Outlook back to the early 1990s or contained in various internal documents.

As at 1 January 2010 New Zealand's reported oil reserves stood at 171.4 million barrels (mmbbls), down from 181.8 million barrels the previous year, while gas reserves stood at 2,076 PJs, up from 1,975 PJs the previous year. 39% of total oil reserves come from the Maari and Tui fields which do not provide any gas to the local market. Half of reported gas reserves lie in the Pohokura field, with a further 22% coming from the Maui and Kapuni fields, the historic mainstays of New Zealand gas supply. The recently developed fields Kupe and Turangi provide for a further 19% of reported gas reserves.

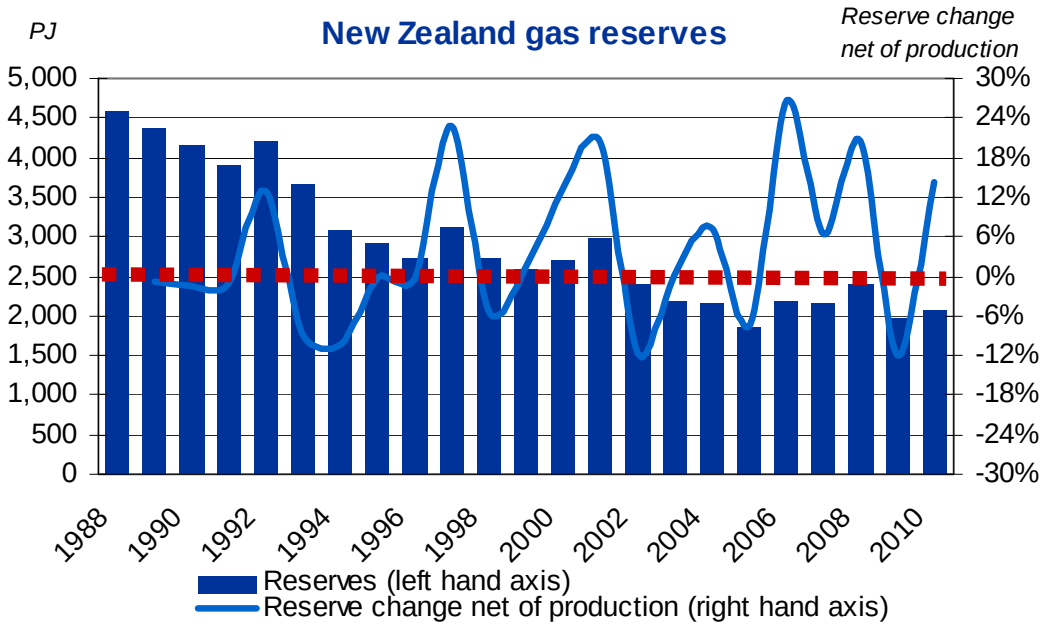
Gas reserves by field - 1 Jan. 2010 (PJ)

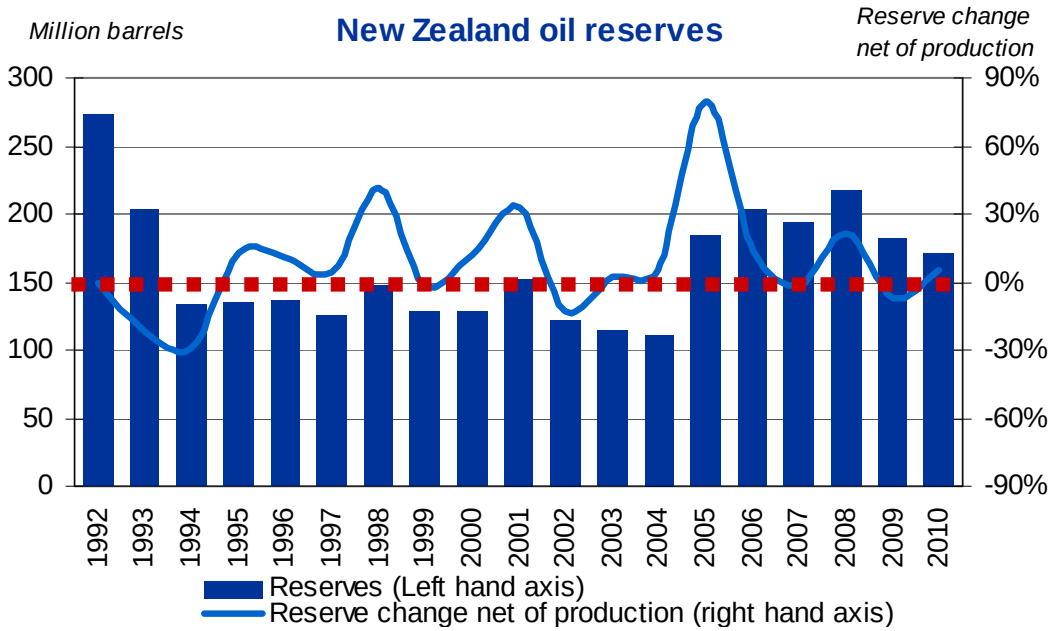


Oil reserves by field - 1 Jan. 2010 (Mmbbls)



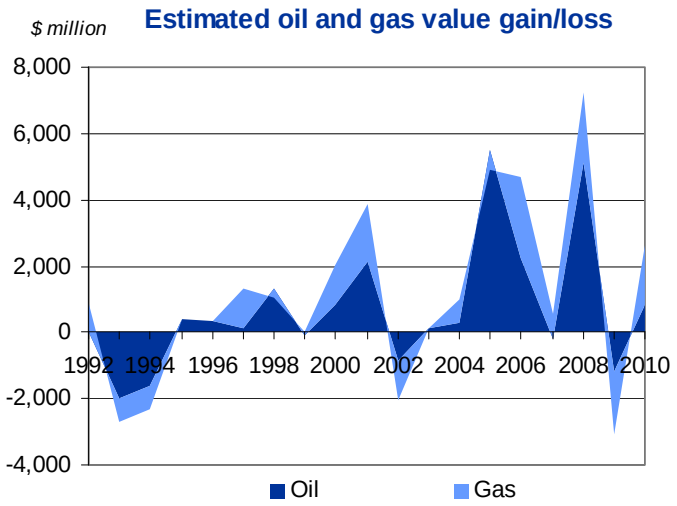
The published reserves figures are proved plus probable reserves, also referred to as P50 or 2P reserves. This means that there should be at least a 50% probability that the actual quantities recovered equal or exceed the 2P estimate.





Since regular reporting commenced there have been substantial revisions in published oil and gas reserves. Oil reserves fluctuated substantially in 1998, 2000, 2001, 2002, 2006, 2007, 2009. Gas reserves fluctuated substantially in 1997, 2000, 2001, 2002, 2006, 2008, 2009 and 2010. The oil reserves upgrades in 2001 and 2005 can be largely explained by the discovery of Pohokura in 2001 (42.8 million barrels) and the discoveries of Maari (49 million barrels) and Tui (26.8 million barrels) in 2005. Likewise, gas reserve upgrades in 2001, 2006 and 2010 can be largely explained by the respective discoveries of Pohokura (700 PJs in 2001), Turangi (144 PJs in 2006) and Kowhai (133 PJs in 2010). Fluctuations in reported oil reserves figures in 1998, 2000, 2002, 2006, 2008 and 2009, however resulted from a substantial revision of reported oil reserve figures from existing producing fields. Likewise, fluctuations in reported gas reserve figures in 1997, 2000, 2002, 2008 and 2009 resulted from a substantial revision of reported gas reserve figures from existing producing fields.

Applying an average export crude price provides an approximate monetary value for oil reserve flucutations and shows reserves additions of up to $5.5 billion and downward losses of up to $2 billion from one year to the next. On the gas side, applying a wholesale price provides an approximate monetary value of gas reserve fluctuations and shows reserves additions of up to $2.4 billion and downward losses of up to $1.9 billion from one year to the next. When combined, New Zealand's oil and gas reserves have risen by up to $7 billion in 2008 or have been revised downward by $3 billion in 2009.



Oil reserves - mmbbls

Year*	Maui	Pohokura	Kupe	Kaimiro**	Kapuni	McKee	Mangahewa	Ngatoro	Tariki/ Ahuroa	Waihapa/ Ngaere	Rimu/ Kauri	Maari	Tui	Others	Total	Production (mmbbls)	Net reserve change	Net % change	Crude price NZ$/barrel	Revenue gain/loss $ million***	Combined oil and gas revenue gain/loss $ million
1988															**-**	12.3					0
1989															**-**	13.7	12.3	**-100%**		0	-56
1990															**-**	13.9	13.7	**-100%**	39.61	541	451
1991															**-**	14.7	13.9	**-100%**	36.37	506	429
1992	84.0	-	134.7	0.6	17.3	15.9	-	-	2.7	17.8	-	-	-	0.1	**273.1**	14.0	287.8	**0%**	39.54	0	896
1993	77.8	-	82.8	0.6	15.5	11.2	-	-	1.4	14.4	-	-	-	0.1	**203.5**	14.8	-55.6	**-21%**	36.11	-2,008	-2,677
1994	71.5	-	30.8	0.6	13.6	6.5	-	-	-	10.9	-	-	-	-	**133.9**	14.0	-54.8	**-29%**	29.27	-1,604	-2,301
1995	82.5	-	23.5	1.2	11.3	8.9	-	0.5	1.5	6.2	-	-	-	-	**135.6**	12.2	15.7	**13%**	24.80	389	380
1996	93.5	-	16.3	1.8	8.9	11.3	-	0.9	2.9	1.6	-	-	-	-	**137.2**	16.3	13.9	**11%**	26.67	370	339
1997	84.7	-	16.3	1.4	7.5	9.2	-	2.8	3.3	0.9	-	-	-	-	**126.1**	21.5	5.2	**4%**	26.96	139	1,302
1998	95.7	-	16.3	1.9	5.5	15.3	0.8	2.2	4.2	4.7	-	-	-	1.4	**147.9**	17.2	43.3	**41%**	30.70	1,330	1,024
1999	84.6	-	16.3	1.7	4.5	13.9	0.7	1.8	5.0	0.4	-	-	-	-	**128.9**	15.0	-1.8	**-1%**	38.39	-71	23
2000	92.9	-	16.3	1.5	5.2	4.8	0.7	1.4	4.8	0.4	-	-	-	-	**128.1**	13.2	14.1	**12%**	59.85	843	2,002
2001	77.8	42.8	16.3	1.2	3.8	5.0	0.7	1.1	3.8	0.5	-	-	-	-	**152.9**	12.5	38.0	**33%**	56.38	2,144	3,900
2002	47.3	42.8	16.3	1.0	6.0	3.6	0.6	1.6	3.2	0.4	-	-	-	-	**122.9**	11.3	-17.5	**-12%**	49.63	-868	-2,063
2003	34.8	42.8	16.3	0.6	4.7	2.0	0.3	1.0	2.1	0.4	8.9	-	-	-	**113.9**	8.7	2.2	**2%**	48.30	106	133
2004	30.6	42.8	16.3	-	4.3	2.3	0.3	3.0	0.6	0.3	10.3	-	-	-	**110.6**	7.6	5.4	**5%**	54.00	294	981
2005	18.3	42.8	16.3	-	5.0	1.9	0.2	3.4	1.1	0.3	9.4	49.0	26.8	10.3	**184.8**	7.1	81.8	**79%**	67.57	5,528	4,890
2006	28.8	42.8	22.0	-	5.2	1.9	0.2	3.3	2.0	0.6	9.0	48.8	27.9	10.0	**202.5**	6.8	24.8	**14%**	91.04	2,259	4,670
2007	22.2	43.1	19.2	1.4	4.8	1.6	-	4.5	1.7	0.5	8.7	49.0	27.9	9.1	**193.7**	15.0	-2.0	**-1%**	95.14	-191	549
2008	24.1	55.9	19.2	1.4	4.3	1.5	2.2	4.4	1.7	0.4	8.6	49.0	35.4	8.9	**217.0**	21.4	38.3	**21%**	133.27	5,107	7,228
2009	11.1	49.2	19.2	1.8	1.9	0.9	2.3	3.3	-	0.1	1.8	51.0	30.3	8.9	**181.8**	19.6	-13.8	**-7%**	87.16	-1,200	-3,076
2010	10.4	41.7	27.0	1.7	2.4	1.6	2.6	3.2	0.2	0.2	2.1	43.1	24.4	10.8	**171.4**		9.2	**6%**		806	2,617

**Reserves figures are from 1 January of the year stated. Figures prior to 1996 should be treated with caution.*

***Kaimiro reserves were grouped with Ngatoro reserves between 2004-2007*

****Average crude export price multiplied by net reserve fluctuation*

Gas reserves - PJ

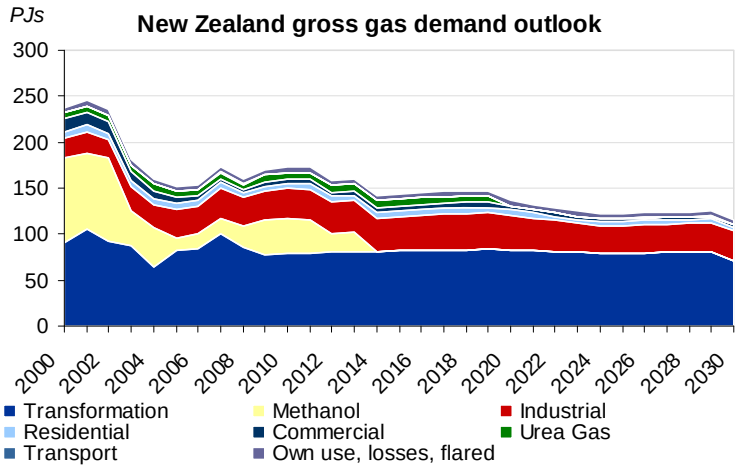
Year*	Maui	Pohokura	Kupe	Kaimiro**	Kapuni	McKee	Mangahewa	Ngatoro	Tariki/ Ahuroa	Waihapa/ Ngaere	Rimu/ Kauri	Turangi	Kowhai	Other	Total	Net natural gas production	Net reserve change	Net % change	Wholesale gas price $/GJ**	Revenue gain/loss $ million***
1988	3,540	-	298	22	400	192	-	-	133	-	-	-		-	**4,585**	172			1.43	
1989	3,378	-	298	21	357	188	-	-	133	-	-	-		-	**4,375**	177	-37	**-1%**	1.51	-56
1990	3,210	-	298	21	311	184	-	-	92	28	-	-		-	**4,143**	177	-56	**-1%**	1.62	-90
1991	3,039	-	298	20	267	179	-	-	92	26	-	-		-	**3,921**	192	-45	**-1%**	1.70	-77
1992	2,594	-	907	29	435	96	-	-	94	25	-	-		27	**4,207**	204	478	**13%**	1.87	896
1993	2,398	-	593	30	406	100	-	-	95	21	-	-		14	**3,654**	198	-349	**-9%**	1.91	-668
1994	2,202	-	278	31	376	103	-	-	95	16	-	-		-	**3,101**	184	-355	**-10%**	1.96	-697
1995	1,929	-	294	21	435	117	-	2	106	9	-	-		-	**2,913**	173	-5	**0%**	1.99	-9
1996	1,655	-	309	12	493	132	-	5	117	2	-	-		-	**2,724**	198	-15	**-1%**	2.00	-30
1997	2,075	-	309	11	468	123	-	4	112	1	-	-		-	**3,103**	212	576	**23%**	2.02	1,163
1998	1,685	-	309	14	436	109	73	5	94	8	-	-		7	**2,740**	188	-151	**-5%**	2.03	-305
1999	1,549	-	309	10	401	91	125	2	110	1	-	-		-	**2,598**	218	46	**2%**	2.04	94
2000	1,551	-	309	9	524	65	125	5	112	1	-	-		0	**2,701**	230	321	**13%**	3.61	1,160
2001	1,337	700	309	12	339	54	125	4	92	1	-	-		0	**2,973**	242	502	**20%**	3.50	1,756
2002	750	700	309	12	402	44	109	4	79	1	-	-		-	**2,410**	230	-321	**-12%**	3.72	-1,195
2003	574	700	309	14	359	52	61	3	64	1	50	-		0	**2,187**	174	7	**0%**	4.10	27
2004	539	700	309	6	343	75	66	-	48	-	78	-		-	**2,164**	155	151	**7%**	4.56	687
2005	346	700	309	8	258	77	47	-	43	-	74	-		-	**1,862**	145	-147	**-7%**	4.35	-638
2006	529	700	281	9	286	68	41	-	41	-	62	144		16	**2,177**	148	459	**27%**	5.25	2,412
2007	439	885	266	17	263	61	61	-	26	-	57	82		-	**2,156**	163	128	**6%**	5.78	740
2008	490	1,064	188	17	239	54	81	14	23	-	54	144		32	**2,399**	154	406	**20%**	5.23	2,121
2009	307	1,012	188	19	118	45	76	20	3	1	0	171		16	**1,975**	159	-270	**-12%**	6.96	-1,876
2010	264	940	266	19	105	50	79	23	3	0	18	175	133	2	**2,076**		260	**14%**		1,811

**Reserves figures are from 1 January of the year stated. Figures prior to 1996 should be treated with caution.*

***Figures back to 1999 from MED returns. Figures prior to 1999 have been adjusted by the Producers Price Index*

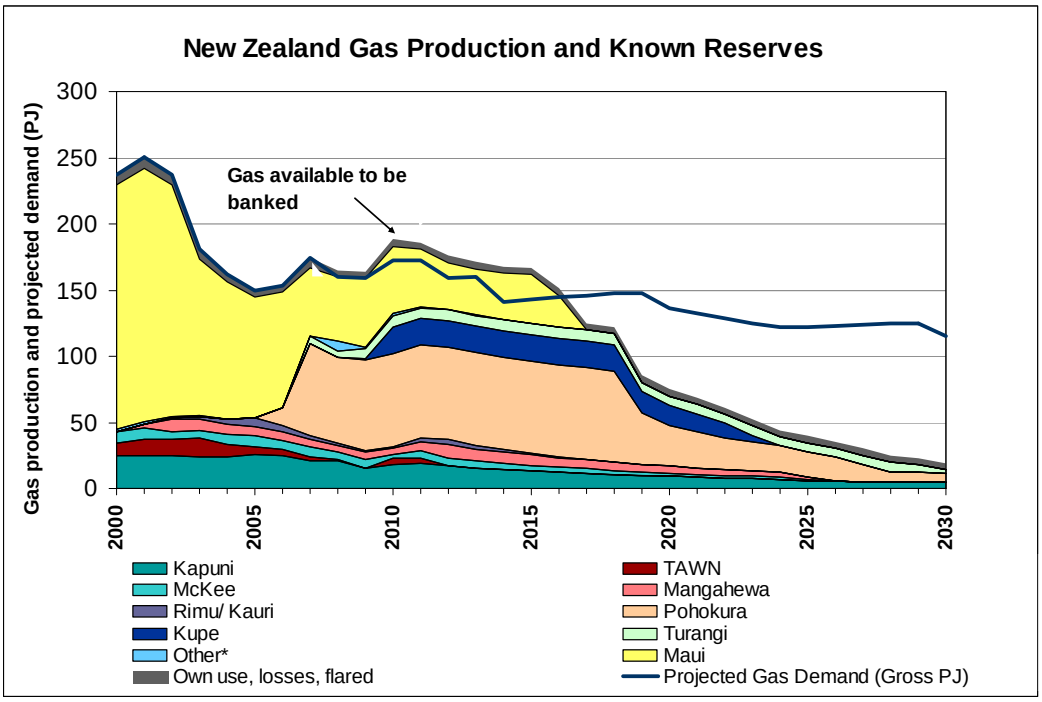
****Wholesale price multiplied by net reserve fluctuation*

Gas supply/demand outlook



Gas reserves form the basis of all supply/demand outlooks undertaken by MED. Supply forecasts for individual fields are drawn directly from companies' half-yearly reports. In the base case forecast, no account is made for new discoveries. On the demand side, the two main variables are gas use for electricity generation and Methanex. Gas demand in electricity is modelled using the Generation Expansion Model used by both the Electricity Commission and MED, leaving Methanex as the main variable. For modelling purposes Methanex is used by MED to balance supply and demand. This invariably leads to a model which shows Methanex leaving New Zealand far earlier than that indicated to officials by Methanex. The only way this can be explained is that Methanex must incorporate upside potential at existing producing fields in its base case forecasts whereas MED limits its projections to what the P50 reserves allow.

The result of this analysis shows demand exceeding supply from 2019.



While manageable, this is considered an extremely tight supply/demand picture and there is a relatively small window for new discoveries to be made and brought onstream before substantial changes in demand are required.

The major caveat to this outlook is the ability of the oil and gas industry to bring onstream new reserves. Since the redetermination of Maui reserves in 2003, the oil and gas industry has discovered and brought onstream 1,110 PJs of new gas reserves, with a reserve replacement ratio of 91% between 1 January 2003 and 1 January 2010[16]. The impact of these reserve additions has been to steadily push out the date at which gas demand is forecast to exceed supply. There is every reason to believe that continued exploration activity will result in further discoveries that will result in the "gas gap" being continually pushed out further.

Upside and downside gas potential at existing fields

In evaluating the ability of oil and gas producers to continue adding reserves, it is important to look at the full spectrum of reserves and contingent resources at existing fields as well as typical lead times for new discoveries. P10 gas reserve figures and contingent resources for 1 January 2009 were collected from gas producers in 4Q 2009 on a confidential basis following a formal request from MED. The arithmetic aggregate P10 reserves for 1 January 2009 stood at 3,118 PJs and contingent resources amounted to between 3,700 PJs to 4,700 PJs.

As per the PRMS guidelines, it is recommended that the arithmetic sum of reserves by field be used for reporting purposes when aggregating across basins or for national reporting purposes. Hence the P90 oil and gas reserves reported in the 2010 edition of the Energy Data File are aggregated arithmetically to provide the national total.

However, the PRMS notes that this is likely to result in a highly conservative figure for aggregated P90 reserves and a highly optimistic figure for P10 reserves given the implicit complete dependency across fields that this implies. Assuming full independence between fields, a probabilistic national P90 gas forecast for 1 January 2010 would give 1,681 PJs and a probabilistic national P10 gas forecast would give 2,564 PJs. The P10 reserve levels equate to approximately 3 years of additional supply at current demand levels, while contingent resources could add a further 14 years of supply on top of these P10 levels.

After contingent resources there are Prospective or Speculative resources, which include prospects, leads and plays, these being fields that are not proven to exist. There are significant leads being pursued in offshore Taranaki and Northland which could potentially feed into existing infrastructure[17]. However, while this view of the upside potential is helpful to bear in mind, it would be imprudent to base public policy on anything more than P50 reserves. Of note, all publicly listed companies in the United States are legally limited to their P90 reserves figures for financial reporting purposes. It is typically these more conservative reserve estimates which are reported in the annual reports of the large international oil companies.

Another important consideration is the length of time it takes to bring new discoveries onstream. Historic discoveries provide a point of reference but are only useful up to a point as development plans for fields like Kupe were delayed for over 15 years due to the market being saturated by low price Maui gas and export not being viable. Based on historic gas discoveries, it takes approximately 2-4 years for onshore discoveries and 6 years for offshore discoveries to be brought

[16] *Reserves replacement ratios are calculated by summing the total reserves added over a period and dividing this by the sum of production over the same period.*

[17] *There are also significant leads being pursued in other petroleum basins (Great South, Canterbury, Reinga, Raukumura, East Coast) but these were specifically excluded from this work on the basis that any discoveries in these basins would not be able to readily feed into existing gas transmission infrastructure. Likewise, coal seam gas and gas hydrates were also excluded on the basis that they were considered either too marginal or too long-term to be useful for this exercise.*

onstream. This means that if none of the upside potential at existing fields were to be proved up, New Zealand would only have a 2-4 year window in which to make new discoveries.

Production lead times for field developments

Field	Discovery year	Production year	Lead time	Reason for lead time
Onshore fields				
Kapuni	1959	1970	11	Establishment of infrastructure
McKee	1979	1984	5	Large scale development
Mangahewa	1997	2001	4	Gas marketing issues
Kaimiro	1982	1983	1	Simple development
Ngatoro	1991	1998	7	Gas flared from 1992-98
Goldie	2002	2002	0	Single flow-line completion
Windsor	2000	2003	3	
Surrey	2002	2003	1	Single flow-line completion
Kahili	2002	2004	2	Gas sales agreement with NGC
Tariki/Ahuroa	1986	1996	10	Gas marketing issues
Waihapa	1985	1992	7	
Piakau	1997	1997	0	Single flow-line completion
Rimu/Kauri	1999	2002	3	Fast track development
Turangi	2005	2006	1	Fast track development
Average lead time			*3.9*	
Offshore fields				
Maui	1969	1979	10	Offshore, large scale development
Pohokura	2000	2006	6	Partially onshore development
Kupe	1987	2009	22	Market conditions
Maari/Manaia	1998*	2008	10	Fast track development
Tui	2003	2007	4	FPSO development
Karewa	2004	-	-	Uncommercial
Forecast lead time for new developments			*6*	

**The original Manaia lead was discovered in 1970*

Understanding recent fluctuations in reported gas reserves

At present, the Energy Data File allows for an identification of fields that have revised reserve figures. However, there is little information as to why companies have revised reserves estimates at particular fields, with minimal explanations provided in the half-yearly reports or in the follow up cross-checking process.

The following information has been gleaned to help partially explain recent reserve fluctuations.

- In 1997 there was a major upgrade of 594 PJs in reported reserves (net of production) from the Maui field, in part linked to the development of the Maui B platform that became fully operational in 1996. This accounted for 95% of the national reserve increase for that year, equivalent to 19% of total reserves.
- In 2000 there was a 166 PJ increase, net of production, in reported reserves at Kapuni, equivalent to 6% of total gas reserves in 2000, which was subsequently revised downward to 150 PJs the following year (equivalent to 6% of total gas reserves in 2001).
- In 2002 there was a major downgrade of 383 PJs at the Maui field, equivalent to 16% of total gas reserves, which triggered a formal redetermination of the field's reserves. This

redetermination was finalised in February 2003 and confirmed that there were substantially lower remaining gas reserves in Maui than previously thought.

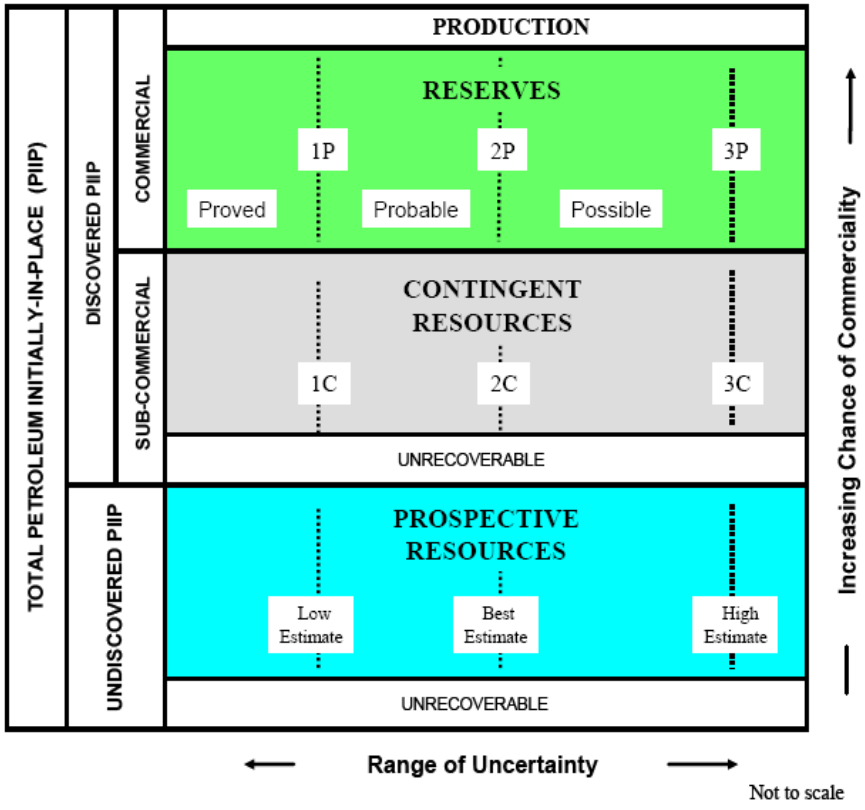
- In 2008 there was a major upgrade of 249 PJs, net of production, at the Pohokura field (equivalent to 10% of national gas reserves) and a 106 PJ increase, net of production, at the Maui field (equivalent to 4% of national gas reserves). For Pohokura, the reserves position was updated following development drilling results which included four new wells in 2007 (POB-02, POB-03, POB-03A and POB-04A). For Maui, the half-yearly report showed a net decline of 23 PJs but this was revised to a net increase 106 PJ in the cross-checking process.
- In 2009 there were reserve downgrades of 131 PJs at the Maui field, 100 PJs at Kapuni, 51 PJs at Rimu and 20 PJs at Tariki/Ahuroa (collectively equivalent to 15% of total gas reserves). For Maui, a full technical revaluation was performed incorporating new data gathered during 2008. For Kapuni, the volumes removed from the reserve position were transferred to contingent resources following the observation of increased water encroachment trend in wells. In the case of Rimu and Tariki/Ahuroa, Origin Energy acquired the fields from Swift Energy and had a completely different view as to remaining recoverable reserves.

Appendix 3: Petroleum Resources Management System

All companies operating in New Zealand are required to report their petroleum reserves under good oil field practice. In the case of reserve reporting it is generally understood that this means the 2007 Petroleum Resources Management System[18]. The PRMS and the associated Guidelines for the Evaluation of Petroleum Reserves and Resources[19] of 2001 should be referred to directly for a full understanding. For ease of reference, the PRMS has been substantially copied out below.

Classification framework

The PRMS sets out a resources classification framework that encompasses 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 considered "conventional" or "unconventional". The PRMS resources classification system defines the major recoverable resources classes: production, reserves, contingent resources, and prospective resources, as well as unrecoverable petroleum.



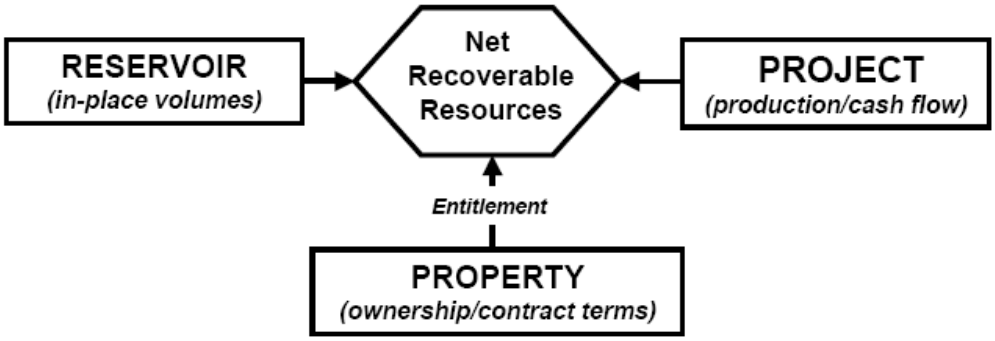
[18] http://www.spe.org/industry/reserves/docs/Petroleum_Resources_Management_System_2007.pdf

[19] http://www.spe.org/industry/reserves/docs/GuidelinesEvaluationReservesResources_2001.pdf

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. Key definitions include:

- **Production** is the quantity of oil and natural gas that has been recovered already (by a specified date). This is primarily output from operations that has already been produced for use by consumers.
- **Reserves** are those quantities of petroleum 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 categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised 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 categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.
- **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.
- **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”).
- **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).

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.



- 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.

Classification and categorisation guidelines

To consistently characterise petroleum projects, evaluations of all resources should be conducted in the context of the full classification system. The PRMS guidelines advise that projects are "classified" based on their chance of commerciality (the vertical axis) and estimates of recoverable and marketable quantities associated with each project are "categorised" to reflect uncertainty (the horizontal axis).

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).

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.

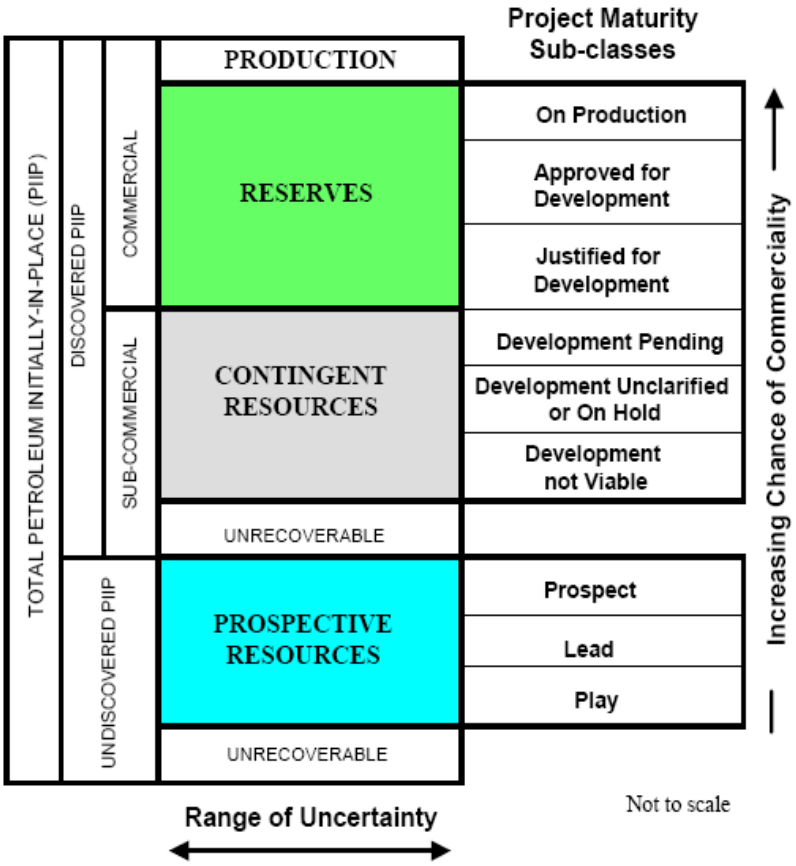
Determination of commerciality

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 (5 years is the recommended benchmark but 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);
- 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; and
- evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

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).



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:

- 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.

Projects may be further characterised by their Economic Status. All projects classified as Reserves must be economic under defined conditions. 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.

Resources categorisation

The horizontal axis in the Resources Classification 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).

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution.

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; and
- 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.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources.

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.

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.

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.

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.

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.

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.

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).

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 localised 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 large area and that are not significantly affected by hydrodynamic influences (also called “continuous-type deposits”). Examples include coalbed methane (CBM), basin-centreed gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialised 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.

Evaluation and reporting guidelines

Commercial evaluations

Investment decisions are based on the entity's view of future commercial conditions that may impact the development feasibility (commitment to develop) and production/cash flow schedule of oil and gas projects. Commercial conditions include, but are not limited to, assumptions of financial conditions (costs, prices, fiscal terms, taxes), marketing, legal, environmental, social, and governmental factors. Project value may be assessed in several ways (e.g., historical costs, comparative market values); the guidelines herein apply only to evaluations based on cash flow analysis.

Cash-flow based resources evaluations

Resources evaluations are based on estimates of future production and the associated cash flow schedules for each development project. 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. The calculation shall reflect:

- The expected quantities of production projected over identified time periods.
- The estimated costs associated with the project to develop, recover, and produce the quantities of production at its Reference Point, including environmental, abandonment, and reclamation costs charged to the project, based on the evaluator's view of the costs expected to apply in future periods.
- The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods including that portion of the costs and revenues accruing to the entity.
- Future projected production and revenue related taxes and royalties expected to be paid by the entity.
- A project life that is limited to the period of entitlement or reasonable expectation thereof.
- The application of an appropriate discount rate that reasonably reflects the weighted average cost of capital or the minimum acceptable rate of return applicable to the entity at the time of the evaluation.

While each organisation may define specific investment criteria, a project is generally considered to be "economic" if its "best estimate" case has a positive net present value under the organisation's standard discount rate, or if at least has a positive undiscounted cash flow.

Economic criteria

Evaluators must clearly identify the assumptions on commercial conditions utilized in the evaluation and must document the basis for these assumptions.

The economic evaluation underlying the investment decision is based on the entity's reasonable forecast of future conditions, including costs and prices, which will exist during the life of the project (forecast case). Such forecasts are based on projected changes to current conditions; SPE defines current conditions as the average of those existing during the previous 12 months.

Economic limit

Economic limit is defined as the production rate beyond which the net operating cash flows from a project, which may be an individual well, lease, or entire field, are negative, a point in time that defines the project's economic life. Operating costs should be based on the same type of projections as used in price forecasting. Operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those cash costs that will actually be eliminated if project production ceases should be considered in the calculation of economic limit). Operating costs should include fixed property-specific overhead charges if these are actual incremental costs attributable to the project and any production and property taxes but, for purposes of calculating economic limit, should exclude depreciation, abandonment and reclamation costs, and income tax, as well as any overhead above that required to operate the subject property itself. Operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue-enhancement approaches, such as sharing of production facilities, pooling maintenance contracts, or marketing of associated non-hydrocarbons.

Interim negative project net cash flows may be accommodated in short periods of low product prices or major operational problems, provided that the longer-term forecasts must still indicate positive economics.

Production measurement

In general, the marketable product, as measured according to delivery specifications at a defined Reference Point, provides the basis for production quantities and resources estimates. The following operational issues should be considered in defining and measuring production. While referenced specifically to Reserves, the same logic would be applied to projects forecast to develop Contingent and Prospective Resources conditional on discovery and development.

Reference point

Reference Point is a defined location(s) in the production chain where the produced quantities are measured or assessed. The Reference Point is typically the point of sale to third parties or where custody is transferred to the entity's downstream operations. Sales production and estimated Reserves are normally measured and reported in terms of quantities crossing this point over the period of interest.

Wet or dry natural gas

The Reserves for wet or dry natural gas should be considered in the context of the specifications of the gas at the agreed Reference Point. Thus, for gas that is sold as wet gas, the volume of the wet gas would be reported, and there would be no associated or extracted hydrocarbon liquids reported separately. It would be expected that the corresponding enhanced value of the wet gas would be reflected in the sales price achieved for such gas.

When liquids are extracted from the gas prior to sale and the gas is sold in dry condition, then the dry gas volume and the extracted liquid volumes, whether condensate and/or natural gas liquids, should be accounted for separately in resource assessments. Any hydrocarbon liquids separated from the wet gas subsequent to the agreed Reference Point would not be reported as Reserves.

Associated non-hydrocarbon components

In the event that non-hydrocarbon components are associated with production, the reported quantities should reflect the agreed specifications of the petroleum product at the Reference Point. correspondingly, the accounts will reflect the value of the petroleum product at the Reference Point. If it is required to remove all or a portion of non-hydrocarbons prior to delivery, the Reserves and production should reflect only the residual hydrocarbon product.

Even if the associated non-hydrocarbon component (e.g., helium, sulphur) that is removed prior to the Reference Point is subsequently and separately marketed, these quantities are not included in petroleum production or Reserves. The revenue generated by the sale of non-hydrocarbon products may be included in the economic evaluation of a project.

Natural gas re-injection

Natural gas production can be re-injected into a reservoir for a number of reasons and under a variety of conditions. It can be re-injected into the same reservoir or into other reservoirs located on the same property for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. In such cases, assuming that the gas will eventually be produced and sold, the gas volume estimated as eventually recoverable can be included as Reserves.

If gas volumes are to be included as Reserves, they must meet the normal criteria laid down in the definitions including the existence of a viable development, transportation, and sales marketing plan. Gas volumes should be reduced for losses associated with the re-injection and subsequent recovery process. Gas volumes injected into a reservoir for gas disposal with no committed plan for recovery are not classified as Reserves. Gas volumes purchased for injection and later recovered are not classified as Reserves.

Underground natural gas storage

Natural gas injected into a gas storage reservoir to be recovered at a later period (e.g., to meet peak market demand periods) should not be included as Reserves.

Production balancing

Reserves estimates must be adjusted for production withdrawals. This may be a complex accounting process when the allocation of production among project participants is not aligned with their entitlement to Reserves. Production overlift or underlift can occur in oil production records because of the necessity for participants to lift their production in parcel sizes or cargo volumes to suit available shipping schedules as agreed among the parties. Similarly, an imbalance in gas deliveries can result from the participants having different operating or marketing arrangements that prevent gas volumes sold from being equal to entitlement share within a given time period.

Based on production matching the internal accounts, annual production should generally be equal to the liftings actually made by the participant and not on the production entitlement for the year. However, actual production and entitlements must be reconciled in Reserves assessments. Resulting imbalances must be monitored over time and eventually resolved before project abandonment.

Resources entitlement and recognition

While assessments are conducted to establish estimates of the total Petroleum Initially-in-Place and that portion recovered by defined projects, the allocation of sales quantities, costs, and revenues impacts the project economics and commerciality. This allocation is governed by the applicable contracts between the mineral owners (lessors) and contractors (lessees) and is generally referred to as “entitlement.” For publicly traded companies, securities regulators may set criteria regarding the classes and categories that can be “recognized” in external disclosures.

Entitlements must ensure that the recoverable resources claimed/reported by individual stakeholders sum to the total recoverable resources; that is, there are none missing or duplicated in the allocation process. (The “2001 Supplemental Guidelines,” Chapter 9, addresses issues of Reserves recognition under production-sharing and non-traditional agreements.)

Contract extensions or renewals

Reserves should not be claimed for those volumes that will be produced beyond the ending date of the current agreement unless there is reasonable expectation that an extension, a renewal, or a new contract will be granted. Such reasonable expectation may be based on the historical treatment of similar agreements by the license-issuing jurisdiction. Otherwise, forecast production beyond the contract term should be classified as Contingent Resources with an associated reduced chance of commercialization. Moreover, it may not be reasonable to assume that the fiscal terms in a negotiated extension will be similar to existing terms.

Similar logic should be applied where gas sales agreements are required to ensure adequate markets. Reserves should not be claimed for those quantities that will be produced beyond those specified in the current agreement or reasonably forecast to be included in future agreements.

In either of the above cases, where the risk of cessation of rights to produce or inability to secure gas contracts is not considered significant, evaluators may choose to incorporate the uncertainty by categorizing quantities to be recovered beyond the current contract as Probable or Possible Reserves.

Estimating recoverable quantities

Assuming that projects have been classified according to their project maturity, the estimation of associated recoverable quantities under a defined project and their assignment to uncertainty categories may be based on one or a combination of analytical procedures. Such procedures may be applied using an incremental (risk-based) and/or scenario approach; moreover, the method of assessing relative uncertainty in these estimates of recoverable quantities may employ both deterministic and probabilistic methods.

Analytical procedures

The analytical procedures for estimating recoverable quantities fall into three broad categories: (a) analogy, (b) volumetric estimates, and (c) performance-based estimates, which include material balance, production decline, and other production performance analyses. Reservoir simulation may be used in either volumetric or performance-based analyses. Pre- and early post discovery assessments are typically made with analog field/project data and volumetric estimation. After

production commences and production rates and pressure information become available, performance-based methods can be applied. Generally, the range of EUR estimates is expected to decrease as more information becomes available, but this is not always the case.

In each procedural method, results are not a single quantity of remaining recoverable petroleum, but rather a range that reflects the underlying uncertainties in both the in-place volumes and the recovery efficiency of the applied development project. By applying consistent guidelines, evaluators can define remaining recoverable quantities using either the incremental or cumulative scenario approach. The confidence in assessment results generally increases when the estimates are supported by more than one analytical procedure.

Analogues

Analogues are widely used in resources estimation, particularly in the exploration and early development stages, when direct measurement information is limited. The methodology is based on the assumption that the analogous reservoir is comparable to the subject reservoir regarding reservoir and fluid properties that control ultimate recovery of petroleum. By selecting appropriate analogues, where performance data based on comparable development plans (including well type, well spacing and stimulation) are available, a similar production profile may be forecast.

Analogous reservoirs are defined by features and characteristics including, but not limited to, approximate depth, pressure, temperature, reservoir drive mechanism, original fluid content, reservoir fluid gravity, reservoir size, gross thickness, pay thickness, net-to-gross ratio, lithology, heterogeneity, porosity, permeability, and development plan. Analogous reservoirs are formed by the same, or very similar, processes with regard to sedimentation, diagenesis, pressure, temperature, chemical and mechanical history, and structural deformation.

Comparison to several analogues may improve the range of uncertainty in estimated recoverable quantities from the subject reservoir. While reservoirs in the same geographic area and of the same age typically provide better analogues, such proximity alone may not be the primary consideration. In all cases, evaluators should document the similarities and differences between the analogue and the subject reservoir/project. Review of analogue reservoir performance is useful in quality assurance of resource assessments at all stages of development.

Volumetric assessment

This procedure uses reservoir rock and fluid properties to calculate hydrocarbons in-place and then estimate that portion that will be recovered by a specific development project(s). Key uncertainties affecting in-place volumes include:

- reservoir geometry and trap limits that impact gross rock volume;
- geological characteristics that define pore volume and permeability distribution;
- elevation of fluid contacts; and
- combinations of reservoir quality, fluid types, and contacts that control fluid saturations.

The gross rock volume of interest is that for the total reservoir. While spatial distribution and reservoir quality impact recovery efficiency, the calculation of in-place petroleum often uses average net-to-gross ratio, porosity, and fluid saturations. In more heterogeneous reservoirs, increased well density may be required to confidently assess and categorise resources.

Given estimates of the in-place petroleum, that portion that can be recovered by a defined set of wells and operating conditions must then be estimated based on analogue field performance

and/or simulation studies using available reservoir information. Key assumptions must be made regarding reservoir drive mechanisms.

The estimates of recoverable quantities must reflect uncertainties not only in the petroleum in place but also in the recovery efficiency of the development project(s) applied to the specific reservoir being studied.

Additionally, geostatistical methods can be used to preserve spatial distribution information and incorporate it in subsequent reservoir simulation applications. Such processes may yield improved estimates of the range of recoverable quantities. Incorporation of seismic analyses typically improves the underlying reservoir models and yields more reliable resource estimates. [Refer to the "2001 SPE Supplemental Guidelines" for more detailed discussion of geostatistics (Chapter 7) and seismic applications (Chapter 8)].

Material balance

Material balance methods to estimate recoverable quantities involve the analysis of pressure behaviour as reservoir fluids are withdrawn. In ideal situations, such as depletion-drive gas reservoirs in homogeneous, high-permeability reservoir rocks and where sufficient and high quality pressure data is available, estimation based on material balance may provide very reliable estimates of ultimate recovery at various abandonment pressures. In complex situations, such as those involving water influx, compartmentalization, multiphase behaviour, and multilayered or low permeability reservoirs, material balance estimates alone may provide erroneous results.

Evaluators should take care to accommodate the complexity of the reservoir and its pressure response to depletion in developing uncertainty profiles for the applied recovery project. Computer reservoir modelling or reservoir simulation can be considered a sophisticated form of material balance analysis. While such modelling can be a reliable predictor of reservoir behaviour under a defined development program, the reliability of input rock properties, reservoir geometry, relative permeability functions, and fluid properties are critical. Predictive models are most reliable in estimating recoverable quantities when there is sufficient production history to validate the model through history matching.

Production performance analysis

Analysis of the change in production rates and production fluids ratios vs. time and vs. cumulative production as reservoir fluids are withdrawn provides valuable information to predict ultimate recoverable quantities. In some cases, before decline in production rates is apparent, trends in performance indicators such as gas/oil ratio (GOR), water/oil ratio (WOR), condensate/gas ratio (CGR), and bottom hole or flowing pressures can be extrapolated to an economic limit condition to estimate reserves.

Reliable results require a sufficient period of stable operating conditions after wells in a reservoir have established drainage areas. In estimating recoverable quantities, evaluators must consider complicating factors affecting production performance behaviour, such as variable reservoir and fluid properties, transient vs. stabilized flow, changes in operating conditions, interference effects, and depletion mechanisms. In early stages of depletion, there may be significant uncertainty in both the ultimate performance profile and the commercial factors that impact abandonment rate.

Deterministic and probabilistic methods

Regardless of the analytical procedure used, resource estimates may be prepared using either deterministic or probabilistic methods. A deterministic estimate is a single discrete scenario within a range of outcomes that could be derived by probabilistic analysis.

In the deterministic method, a discrete value or array of values for each parameter is selected based on the estimator's choice of the values that are most appropriate for the corresponding resource category. A single outcome of recoverable quantities is derived for each deterministic increment or scenario.

In the probabilistic method, the estimator defines a distribution representing the full range of possible values for each input parameter. These distributions may be randomly sampled (typically using Monte Carlo simulation software) to compute a full range and distribution of potential outcome of results of recoverable quantities (see "2001 Supplemental Guidelines," Chapter 5, for more detailed discussion of probabilistic reserves estimation procedures). This approach is most often applied to volumetric resource calculations in the early phases of an exploitation and development projects. The Resources Categorisation guidelines include criteria that provide specific limits to parameters associated with each category. Moreover, the resource analysis must consider commercial uncertainties. Accordingly, when probabilistic methods are used, constraints on parameters may be required to ensure that results are not outside the range imposed by the category deterministic guidelines and commercial uncertainties.

Deterministic volumes are estimated for discrete increments and defined scenarios. While deterministic estimates may have broadly inferred confidence levels, they do not have associated quantitatively defined probabilities. Nevertheless, the ranges of the probability guidelines established for the probabilistic method influence the amount of uncertainty generally inferred in the estimate derived from the deterministic method. Both deterministic and probabilistic methods may be used in combination to ensure that results of either method are reasonable.

Aggregation methods

Oil and gas quantities are generally estimated and categorized according to certainty of recovery within individual reservoirs or portions of reservoirs; this is referred to as the "reservoir level" assessment. These estimates are summed to arrive at estimates for fields, properties, and projects. Further summation is applied to yield totals for areas, countries, and companies; these are generally referred to as "resource reporting levels." The uncertainty distribution of the individual estimates at each of these levels may differ widely, depending on the geological settings and the maturity of the resources. This cumulative summation process is generally referred to as "aggregation."

Two general methods of aggregation may be applied: arithmetic summation of estimates by category and statistical aggregation of uncertainty distributions. There is typically significant divergence in results from applying these alternative methods. In statistical aggregation, except in the rare situation when all the reservoirs being aggregated are totally dependent, the P90 (high degree of certainty) quantities from the aggregate are always greater than the arithmetic sum of the reservoir level P90 quantities, and the P10 (low degree of certainty) of the aggregate is always less than the arithmetic sum P10 quantities assessed at the reservoir level. This "portfolio effect" is the result of the central limit theorem in statistical analysis. Note that the mean (arithmetic average) of the sums is equal to the sum of the means; that is, there is no portfolio effect in aggregating mean values.

In practice, there is likely to be a large degree of dependence between reservoirs in the same field, and such dependencies must be incorporated in the probabilistic calculation. When dependency is present and not accounted for, probabilistic aggregation will overestimate the low estimate result and underestimate the high estimate result. (Aggregation of Reserves is discussed in Chapter 6 of the "2001 Supplemental Guidelines.")

The aggregation methods utilised depends on the business purpose. It is recommended that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. Results reporting beyond this level should use arithmetic summation by category but should caution that the aggregate Proved may be a very conservative estimate and aggregate 3P may be very optimistic depending on the number of items in the aggregate. Aggregates of 2P results typically have less portfolio effect that may not be significant in mature properties where the statistical median approaches the mean of the resulting distribution.

Various techniques are available to aggregate deterministic and/or probabilistic field, property, or project assessment results for detailed business unit or corporate portfolio analyses where the results incorporate the benefits of portfolio size and diversification. Again, aggregation should incorporate the degree of dependency. Where the underlying analyses are available, comparison of arithmetic and statistical aggregation results may be valuable in assessing impact of the portfolio effect. Whether deterministic or probabilistic methods are used, care should be taken to avoid systematic bias in the estimation process.

It is recognized that the monetary value associated with these recoveries is dependent on the production and cash flow schedules for each project; thus, aggregate distributions of recoverable quantities may not be a direct indication of corresponding uncertainty distributions of aggregate value.

Aggregating resource classes

Petroleum quantities classified as Reserves, Contingent Resources, or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources and/ or Prospective Resources will not achieve commercial production.

Where the associated discovery and commerciality risks have been quantitatively defined, statistical techniques may be applied to incorporate individual project risk estimates in portfolio analysis of volume and value.

Appendix 4: International Reserve Reporting Regimes

Australia

Legislative and reporting requirements

The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production (Directions)[20] requires in sections 550, 650 and 651 that licensees shall provide estimates of hydrocarbons initially in place and reserves in Title Assessment Reports. Sections 550(3) and 550(4) almost mirror sections 651(3) and 651(4) and require that licensees must provide the following information:

- The estimated amount of recoverable petroleum in a commercial pool or in-place petroleum in a currently non-commercial pool; and
- the data upon which the estimates used in the report are based and shall be accompanied by any specific reports made during the period.
- When a field study resulting in a revised estimate of the amount of recoverable or in-place petroleum in a pool has been carried out, two copies of a report of that study and the revised estimate shall be made available and distributed as directed by the Director.

This Schedule is part of the Petroleum (Submerged Lands) Act 1967[21] which was repealed on 1 July 2008. However this instrument remains in force under the transitional provisions in clause 4 of schedule 6 to the Offshore Petroleum and Greenhouse Gas Storage Act 2006[22]. The Schedule is supplemented by guidelines for reporting and submission of petroleum data[23] which further specifies that these reports include:

- Hydrocarbons initially in place and reserves – Changes in estimates of hydrocarbons initially in place and reserves should be identified by reference to the Field Development Plan (FDP) base case and/or to the case in the previous TAR, and accompanied by the data and reports on which they are based. Reserves should be reported in the following categories, where compositional data is available:
    - Gas (methane plus ethane)
    - LPG (propane plus butane)
    - Condensate (C5+) and
    - Crude oil

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20 http://www.ret.gov.au/resources/Documents/Upstream%20Petroleum/PSLA_Schedule_of_Specific_Reqs_24_11_05200511241037 50.pdf

21 http://www.comlaw.gov.au/ComLaw/Legislation/ActCompilation1.nsf/0/1EC5D9AE4C27123CCA256FBC0082559F/$file/PetrolSubmerLand1967_WD02.pdf

22 http://www.comlaw.gov.au/ComLaw/Legislation/ActCompilation1.nsf/0/63163B84A4841195CA257694000F9B58?OpenDocument

23 https://www.ga.gov.au/image_cache/GA11827.pdf

For non-commercial fields, technically recoverable volumes should be reported.

Estimates of hydrocarbons-in-place and reserves for each reservoir are also required in field development plans which are required in the following circumstances:

- An application for a Production Licence, or
- An application for consent to make a major change to an accepted FDP including development of new fields within an existing production licence, or
- Identification of a new or increased risk to the resource, or
- Before a period of a 5 years after acceptance of the FDP has elapsed;
- Application for consent to cease production.

Publicly available information

Geoscience Australia publishes an annual estimate of petroleum reserves by basin[24]. The report breaks down reserves by Category 1 (P90 + P50, or proved + probable) and Category 2 (estimates of recoverable reserves which have not yet been declared commercially viable; they may be either geologically proved or are awaiting further appraisal) for crude, condensate, LPG and natural gas.

In 2010 Geoscience Australia and ABARE were commissioned by the Australian Government Department of Resources, Energy and Tourism to undertake a comprehensive and integrated scientific and economic assessment of Australia's energy resources[25]. The report included the following:

- economic demonstrated and sub-economic resources for crude, condensate, LPG and natural gas reserves by basin;
- estimates of undiscovered resources by basin and by range (P95, mean, P5);
- the scope for enhanced oil recovery from identified fields; and
- estimates of shale oil resources, coal seam gas, tight gas and shale gas by basin.

New Zealand

Legislative and reporting requirements

Reporting requirements are set out under section 90A of the Crown Minerals Act which was inserted, as from 18 October 2004, by section 4 of the Crown Minerals Amendment Act 2004. Section 90A reads:

1. Every holder of a permit relating to petroleum must provide to the Secretary all information in connection with petroleum reserves and petroleum production that is prescribed as information that must be provided under this section.
2. The information must be provided in accordance with regulations made under this Act.
3. The Secretary may, in accordance with regulations made under this Act, publish all or any part of the information provided under this section.

[24] http://www.ga.gov.au/resources/spreadsheet/ogra-2008-all.xls

[25] *See chapters 3 and 4* https://www.ga.gov.au/image_cache/GA16769.pdf

4. For the purposes of this section, the holder of a permit relating to petroleum includes every person who is a holder of a license issued under any previous enactment in respect of petroleum.

Penalties for non-compliance of section 90A are set out in section 101(2) which stipulates: "Every person who commits an offence against section 100(2) is liable on summary conviction to a fine not exceeding $10,000, and, if the offence is a continuing one, to a further fine not exceeding $1,000 for every day or part of a day during which the offence continues."

Section 100(2) reads: *"Every person commits an offence against this Act who contravenes, or permits a contravention of, any of the following: a) Section 33, which relates to compliance with permit conditions and with this Act;…"*

The Crown Minerals (Petroleum) Regulations 2007 sets out requirements for the reporting of reserves and resources in the following situations:

1. s19: Application for mining permit (unless allocated by public tender);
2. s22: Application to extend duration of exploration permit for purpose of discovery appraisal;
3. s23: Application to extend duration of mining permit;
4. s38: Half-yearly report on prospecting or exploration activities;
5. s39: Half-yearly report on mining activities and production operations.

S19: Application for mining permit (unless allocated by public tender)

S19(2)(e) states that the application must be accompanied by a report that: *"i) sets out the reserves and proposed work programme for the development of the field concerned; and ii) includes the information described in Schedule 3."*

S8 of Schedule 3 states that companies must provide reserves information, including:

a) structure maps, cross sections, or models showing the areal and vertical extent of the field and the hydrocarbon contacts; and
b) a statement of the hydrocarbons-in-place, including –
  i. a description of the methodologies used to calculate their volume and distribution; and
  ii. the assigned probabilities for oil, gas, and condensate (with details for each production layer or zone); and
  iii. the field totals; and
c) recoverable hydrocarbon estimates, including their assigned probabilities, and production forecasts for individual wells and field totals (irrespective of any gas sales contracts); and
d) a reservoir model or models.

S22: Application to extend duration of exploration permit for purpose of discovery appraisal

S22(1)(f) states that an application to extend the duration of an exploration permit for the purpose of appraising a discovery must be accompanied by a report that includes the information described in Schedule 4. S10 of Schedule 4 includes details of petroleum volumes, including:

a) for petroleum in place, -
  i. expected volumetric and material balance estimates of oil, gas, and condensate with details for each production layer or zone; and
  ii. field totals and either the cumulative distribution or range of estimates of oil, gas, and condensate for each production layer or zone; and

iii. a discussion of the basis for the estimates under subparagraphs (i) and (ii) and the uncertainties in the calculations; and

b) for petroleum recovery, -

i. estimates of expected reserves for each production layer or zone; and

ii. field totals and either the cumulative distribution or range of estimates of expected reserves for each production layer or zone; and

iii. a discussion of the basis for the estimates under subparagraphs (i) and (ii) and the uncertainties in the calculations.

s23: Application to extend duration of mining permit

S23(1)(f) states that an application to extend the duration of a mining permit must be accompanied by so much of the information supplied in an application for a mining permit (unless allocated by public tender) as is required under this regulation. This would include the same reserves information as set out in s8 of Schedule 3.

s38: Half-yearly report on prospecting or exploration activities

S38(1) states that a permit holder must supply to the Secretary, not later than 40 working days after the end of each half-year, a report on any prospecting or exploration activities that have taken place under the permit concerned during that half-year. S38(2)(b) goes on to say that the report must contain as much of the information described in Part 1 of Schedule 6 as is applicable to the permit in that half-year. S5 of Part 1 of Schedule 6 states that the information to be provided includes petroleum initially in place and gas initially in place estimates from a discovery or from ongoing appraisal of a discovery. S6 of Part 1 of Schedule 1 goes on to include recoverable hydrocarbon resource or reserve estimates (stating the range of uncertainties) from a discovery or ongoing appraisal of a discovery.

s39: Half-yearly report on mining activities and production operations

S39(1) states that a permit holder must supply to the Secretary, not later than 40 working days after the end of each half-year, a report on the mining activities and any production operations that have taken place under the permit concerned during that half-year. S39(2) goes on to say that the report must include the information described in Part 2 of Schedule 6. S18 of Part 2 of Schedule 6 is a status report on:

a) petroleum reserves, including remaining petroleum and gas in place (including an explanation of the methodology used to calculate the reserves); and

b) P90 and P50, or proven and probable estimates (1P and 2P estimates) for remaining and ultimately recoverable oil and gas (including an explanation of the methodology used to calculate the estimates).

Disclosure of information

Section 60 provides broad powers to the Secretary to disclose petroleum reserves and production information. The section reads:

1. The Secretary may, from time to time, make publicly available any of the following information:

a. petroleum production and field reserves, including estimates of P90 and P50 remaining reserves and ultimately recoverable reserves;

b. petroleum production profiles in relation to mining permits and existing privileges;

c. *resource estimates from discoveries or appraisals under any exploration permit, mining permit, or existing privilege.*

Any information disclosed under subclause (1)(c) must state the range of uncertainties used in estimating the resource.

Publicly available information

MED has historically only published P50 ultimate recoverable and remaining P50 reserves estimates by field for oil and gas at all producing and non-producing fields in the annual Energy Data File[26]. As from 2010, MED has also commenced publishing P90 ultimate recoverable and remaining P90 reserves estimates for oil and gas at all producing and non-producing fields in the Energy Data File.

Norway

Legislative framework

The Petroleum Activities Act (Act 29 November 1996 No. 72)[27] is the core piece of legislation relating to petroleum activities in Norway. Section 4-2 relates to a plan for development and operation of petroleum deposits and stipulates that the plan shall contain an account of "resource aspects". Section 10-4 relates to material and information concerning petroleum activities and reads: "Material and information which the licensee, operator, contractor etc. possesses or prepares in connection with planning and implementation of petroleum activities pursuant to this Act shall be available in Norway and may be required to be submitted free of charge to the Ministry or to anyone designated by the Ministry. Such material and information shall be submitted in a format decided by the Ministry to the extent this is deemed reasonable. In this connection, the Ministry may also require analyses and studies to be carried out."

The primary legislation is supported by the Petroleum Regulations promulgated by Royal Decree 27 June 1997[28]. Key information relevant to reserves and resources include:

- *As soon as possible and no later than three months, the licensee shall submit data, records and results from exploration activities to the Norwegian Petroleum Directorate. Unless the Norwegian Petroleum Directorate requests raw data to be submitted, data requiring processing in excess of 3 months shall be submitted as soon as they are processed. The licensee shall furthermore state whether the results etc from the exploration activities are to be commercially available.* (Section 6)
- *An application for a production licence must contain a geological evaluation of the area or areas.* (Section 8)
- *When a petroleum deposit has been proven by drilling, the licensee shall submit to the Norwegian Petroleum Directorate information on plans for further exploration as well as results from exploration of the deposit. An evaluation of the petroleum deposit shall be submitted in writing to the Norwegian Petroleum Directorate within six months of the*

[26] *http://www.med.govt.nz/upload/73585/H%20-%20Oil%20and%20Gas%20Reserves.pdf*

[27] *http://www.npd.no/en/Regulations/Acts/Petroleum-activities-act/*

[28] *http://www.npd.no/en/Regulations/Regulations/Petroleum-activities/*

deposit being proven. If probability of the petroleum deposit having mobile petroleum has been established through tests, sampling or logging, the licensee shall in addition indicate the size of the petroleum deposit and submit plans for the continued activities. The Norwegian Petroleum Directorate may require further evaluations and information to be submitted. (Section 16)

- *An annual status report for fields in production shall be submitted to the Norwegian Petroleum Directorate by 1 November each year.* (Section 47)
- *Reporting to the National Budget process shall be submitted to the Ministry and to the Norwegian Petroleum Directorate. The reporting shall include economical company data, projects, resource volumes and prognoses of production, costs and environmental emissions as specified by the recipient.* (Section 50a)
- *The licensee shall, upon request from the Ministry, provide information on planned, ongoing or concluded research and development projects with relevance for the petroleum activities on the Norwegian continental shelf.* (Section 51)
- *The Norwegian Petroleum Directorate may decide what standard format shall be used in submission of material and information, as well as routines for such submission to the extent this is considered reasonable.* (Section 53)
- *The licensee is obliged, through the operator, to make information about petroleum activities publicly available to the greatest possible extent as and when such information becomes available to the licensee.* (Section 77)

The Resource Management Regulations 2001[29] provide supplementary provisions within the areas under the Petroleum Activities Act and the Petroleum Activities Regulations which have been delegated to the Norwegian Petroleum Directorate. Key sections include:

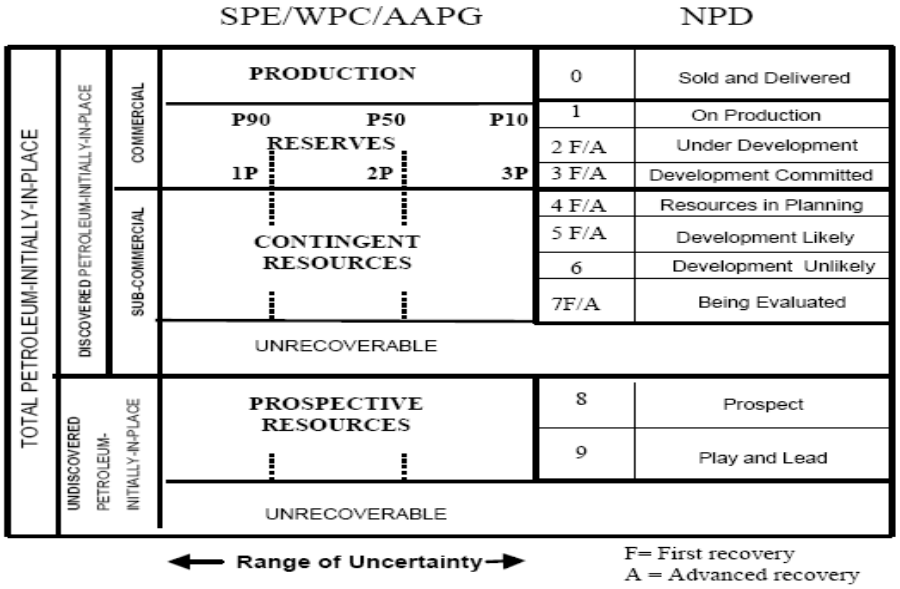
- Section 13 relates to the classification of petroleum resources on the Norwegian continental shelf and reads: *"The petroleum resources shall be classified in accordance with the resource classification system of the Norwegian Petroleum Directorate. The originally recoverable petroleum resources shall be classified according to their position in the development chain from a discovery is made, or a new effort to increase the recoverable resources of a field is identified, and up to the point when the resources have been produced. A discovery or a field may have resources of several classes. All petroleum resources shall to the extent possible be designated by P10 - P expected - P90."*
- Section 24 relates to final reporting of geological and reservoir technical well data. It reads: *"The licensee shall submit a final geological and reservoir technical report in respect of each well / well path to the Norwegian Petroleum Directorate no later than six months after the individual drilling and well activity has been completed. In addition to well data in digital format the report shall contain an overview of all collected data and analyses as well as factors, which may affect the measurement results. In respect of wildcat wells the Norwegian Petroleum Directorate requires both the prognosis and the result to be submitted by completing a particular form in digital format, which is to be enclosed with the Final Report. In the case of discoveries also the discovery evaluation report shall be submitted. All depths shall be related to the drill floor/rotary table (RKB), and the logs shall indicate measured depth (MD) and true vertical depth (TVD). Information enabling the conversion of measured depth into vertical depth, as well as the well path geometry, shall also be included."*
- Section 29 relates to the contents of annual status reports for fields in production. It reads: *"The report shall provide information to the authorities on matters relating to production on*

[29] http://www.npd.no/Global/Engelsk/5%20-%20Rules%20and%20regulations/NPD%20regulations/Ressursforskriften_e.pdf

the field, including measures taken during the preceding period, and measures planned to be carried out in the coming year. The report shall also contain necessary explanations in respect of prognoses and resource estimates given in national budgeting reports, including basic assumptions, and of amendments in relation to the previous year's report. The following main issues shall be covered in the report: general field status, activity report, plans for the period ahead."

Norwegian resource classification system

The Norwegian resource classification system[30] is based on the SPE/WPC/AAPG 2000 classification (a forerunner to the current PRMS) but expanded to utilise categories that differentiate projects based on their commerciality, that is, there maturity towards full producing status. These categories can also be viewed as qualitative measures of commercial risk or chance of commerciality.



The horizontal axis relates to the uncertainty in recoverable hydrocarbon quantities associated with each development project. There may be several projects recovering oil and gas from the same accumulation, and these may be in different stages of maturity, and thus in different categories. The NPD has found it to be convenient to distinguish between the first project (F) and additional projects (A). For example, the incremental recovery associated with an Enhanced Oil Recovery (EOR) project would be tracked using the "A" attribute and the quantities associated with primary recovery project use the "F" modifier while the estimate of original oil in-place may remain constant.

Probabilistic hurdles are similar to the SPE guidance, that is, low estimate/P90 or P80 and high estimate/P10 or P20. The P80/P20 option is rarely used and was included to accommodate major issuers who used that convention in earlier times. The NPD substitutes the term "base estimate" for best estimate. It reflects the current understanding of the extension, characteristics and recovery factor of the reservoir. The base estimate can be calculated deterministically or stochastically. If calculated by a stochastic method, it should correspond to the mean value (not the median/P50).

[30] http://www.npd.no/Global/Engelsk/5%20-%20Rules%20and%20regulations/Guidelines/Ressursklassifisering_e.pdf.

As the NPD classification is developed for the resource management needs of the Norwegian Government and the business process management needs of Norwegian companies, emphasis has been more on reflecting changes in ultimate recoverable estimates than on annual financial reporting. The concept of proved reserves according to deterministic criteria is not recognised in the SEC or SPE definitions. P90 reserves are however both a reasonable and simple, well defined substitute, remembering that future, uncommitted projects are not allowed to contribute to the 2P nor 3P reserves as this would distort the P90 of the distribution.

While the terms Proved, Probable and Possible are not utilized, the definitions of low/1P, base/2P, and high/3P estimated quantities allow derivation of these entities if required (notwithstanding that the base is the mean and not P50).

The NPD defines a discovery as one petroleum deposit, or several petroleum deposits collectively, which have been discovered in the same wildcat well, in which through testing, sampling, or logging there has been established a probability of the existence of mobile hydrocarbons (includes both a commercial and a technical discovery).

The NPD does not give definitions of commercial/economic or sub-commercial/sub-economic but depends on the status categories to segregate Reserves from Contingent Resources. Contingent Resources are defined as petroleum resources that have been discovered but no decision has yet been taken regarding their (development for) production. It is noted that their category 3 (reserves which the licensees have decided to recover) may include projects for which the authorities have not yet approved a Plan of Development (**PDO**) or granted exemption there from. Thus the differentiation of Reserves from Contingent resources may seem to rest solely on the licensees' internal commitment to proceed with development. Under the Petroleum Activities Act, the licensees are however given the right to produce the petroleum The government approval of the PDO is an occasion to align interests in the way development will take place and not an occasion to remove a right already granted.

Reporting requirements

Pursuant to Regulation 50A of the Petroleum Activities Regulations. An Excel spreadsheet[31] and accompanying guidelines[32] are sent to all field operators as part of the revised national budget (**RNB**). The spreadsheet requires operators to report for each discovery:

- Low, base and high estimates for oil, associated liquid (NGL, condensate), associated gas, and free gas for resources originally in place
- Low, base and high estimates for oil, gas and condensates, as well as a base estimate for NGL for all categories of reserves (P90, P50, P10) as well as for contingent resources where the resources are either in the planning phase or where recovery is likely but not clarified. Detailed yearly profiles are also required for production and injection data, sale of petroleum, income profiles and transport profiles, investments, operating costs, tariffs, other costs, assumptions for environmental emissions/discharges and other data, consumption of natural gas and diesel, CO_2 discharge, NO_X and nmVOC & CH_4 discharge.
- Monthly production data for the following year
- Low, base and high estimates for oil, gas and condensates, as well as a base estimate for NGL for all recoverable resources under categories 6 and 7 of the Norwegian resource

[31] http://www.npd.no/en/Reporting/National-budget/

[32] http://www.npd.no/Global/Norsk/5%20-%20Regelverk/Skjema/RNB/RNB2010_guidelines.pdf

classification system. This includes resources where recovery is not very likely or which have not been evaluated.

- Risked resource estimates in prospects with a low, base and high estimate for oil, NGL, condensate and gas. Information on the name of the prospect included in the resource estimate, the number of mapped prospects that can be linked to the field, the number of prospects drilled in the past two years, the resource growth from exploration in the past two years, the number of prospects planned for drilling in the upcoming year, the expected (risked) resource growth in the upcoming year, and the number of planned prospects for drilling in the following four years must also be provided.
- A detailed explanation of any changes in resource estimates in relation to previous reports.

The Annual Status Reports conducted pursuant to regulation 47 of the Petroleum Activities Regulations and regulation 29 of the Resource Regulations supplements the authorities' reporting to the Revised National Budget (RNB) and provides information for the authorities' "Performance Indicator Analysis for Fields" (PIAF). Guidelines for annual status report for fields in production[33] require the following reserve and resource information from companies:

- Overview of reserve growth on the field and explanation of significant changes in original reserves in place and recoverable reserves
- Explanations of changes in resource estimates or resource categories in reporting to RNB, compared with the previous year's report.
- New resources proven within the area of the production license which contains the field should be mentioned

Table 2-1 Expected, P90 and P10 In-Place Volumes

	P90	Expected	P10
OIIP	*< Mill Sm3 >*	*< Mill Sm3 >*	*< Mill Sm3 >*
CIIP	*< Mill Sm3 >*	*< Mill Sm3 >*	*< Mill Sm3 >*
GIIP	*< Bill Sm3 >*	*<Bill Sm3 >*	*< Bill Sm3 >*

-

Table 2-2 Overview of Original and Updated Reserves

	Reserves			
	Gas (Bill Sm³)	*NGL (tonnes)*	*Oil (Mill Sm³)*	*Condensate (Mill Sm³)*
Original estimate (PDO)				
Revised estimate (2009)				

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Table 2-3 Maturing Reserves (oil and gas – accumulated)

	Target 2010	Ambitions 2015	Ambitions 2020	Vision
Maturing reserves (unrisked)	*< Mill Sm3 >*	*< Mill Sm3 >*	*< Mill Sm3 >*	*< Mill Sm3 >*
Maturing reserves (risked)	*< Mill Sm3 >*	*< Mill Sm3 >*	*< Mill Sm3 >*	*< Mill Sm3 >*

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[33] http://www.npd.no/Global/Engelsk/5%20-%20Rules%20and%20regulations/Forms/Annual%20status%20report/Form2009.pdf

Table 2-4 Current Field Volumes (Oil)*

	Field Volumes (Mill Sm3) and Recovery Factor (%)			
Reservoir/Formation	*A*	*B*	*C*	*D*
STOOIP	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*
Mobil oil	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*
Current recovery factor (%) (31.12.2008)	*< % >*	*< % >*	*< % >*	*< % >*
OIP(RTM); Remaining Trapped Microscopic	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*
OIP(RTV); Remaining Trapped Unswept	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*
OIP(UDR) Undrained	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*	*< Mill Sm3>*

Table 2-5 Current Field Volumes (Condensate)

	Field Volumes (Mill Sm3 o.e.) and Recovery Factor (%)			
Reservoir/Formation	*A*	*B*	*C*	*D*
STCOIP	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*
Mobil condensate	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*
Current recovery factor (%) (31.12.2008)	*< % >*	*< % >*	*< % >*	*< % >*
CIP(RTSP); Remaining Trapped Single Phase	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*
CIP(RTIG); Remaining Trapped in Gas	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*
CIP(UDR) Undrained	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*	*< Mill Sm3 o.e.>*

Finally, the NPD asks that all operating companies deliver a report with prospect data for the production licences where the company is operator, pursuant to section 50a of the Petroleum Act. Information sought includes[34]:

- Resources in place;
- Recoverable resources;
- Technical probabilities (reservoir, charge, trap, retention, oil to gas ratio);
- Commercial probabilities;
- Geological information (trap type, structure, water depth);
- Reservoir parameters (depth of top of prospect, area of closure, gross rock volume, hydrocarbon column, reservoir thickness, net/gross fraction, porosity (fraction), water saturation, Bg (fraction), 1/ B_0 (fraction), recovery factor main phase, recovery factor associated phase, gas oil ratio free gas, gas oil ratio oil, temperature at top of reservoir, pressure at top of reservoir); and
- Geographical coordinates.

Publicly available information

Based on the information received from operators, the Norwegian Petroleum Directorate publishes an annual resources report: "The petroleum resources on the Norwegian continental shelf"35. The report contains a detailed breakdown of undiscovered resources, possible measures for improved recovery, contingent resources in discoveries, contingent resources in fields, reserves (classified as those reserves "on production", "under development" or "development committed") and those quantities already sold for oil, gas, NGL and condensate. The report also includes five-year projections for production, investment and operating costs and greenhouse gas emissions. A similar resource breakdown is provided in the annual "Facts – the Norwegian Petroleum Sector"

[34] https://npdmap1.npd.no/website/npdgis/Prospect/ProspectData_reporting_example_med_style_oil_or_gas_case.xml

[35] http://www.npd.no/Global/Engelsk/3%20-%20Publications/Resource%20report/Resource%20report%202009/Ressursrapporten%202009%20engelsk.pdf

report36 published jointly by the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate. However, the Facts book goes further and provides a breakdown for the North Sea, the Norwegian Sea, the Barents Sea as well as a total Norwegian figure.

United Kingdom

Legislative framework

Reserves figures in the United Kingdom are collected by the Licensing, Exploration and Development Branch (**LED**) which is part of the Energy Development Unit (**EDU**) of the Department of Energy and Climate Change (**DECC**). Section 7 of the Energy Act 2008 relates to model clauses and allows the Secretary of State to make regulations prescribing model clauses for licenses[37]. The Petroleum Licensing (Production) (Seaward Areas) Regulations 2008[38] set out the model clauses prescribed for production licenses in seaward areas. Clause 30(3) of the model clauses has a generic catch-all provision which is used to collect reserves information. It reads: "The Licensee shall furnish the Minister with such information as the Minister may from time to time request about any aspect of activities of the Licensee which are attributable directly or indirectly to the grant of this licence, except that the Licensee shall not by virtue of this paragraph be required to furnish information in respect of his activities in connection with any crude oil after he has appropriated it for refining by him."

Other important points to note are:

- All reports are confidential but may be used to generate reports and surveys of a general nature (section 32); and
- The Licensee must permit any person in the service or employment of the Crown to inspect, take copies of and make notes from, all records of any kind kept by the Licensee (section 33).

Reporting requirements

DECC conducts an annual survey of petroleum reserves between January and March each year with the results published in August[39]. The survey is conducted in the form of an Excel spreadsheet sent to all operators[40] accompanied by reserves definitions and notes on completion. The following information is required:

- Stock Tank Oil Initially In Place;
- gas Initially In Place;
- basis of reserve estimate;
- 1P, 2P and 3P reserve estimates for oil, condensate, NGL, and sales gas respectively;

[36] *See chapter 10 at* *http://www.npd.no/Global/Engelsk/3%20-%20Publications/Facts/Facts_2009.pdf*

[37] *http://www.statutelaw.gov.uk/content.aspx?LegType=All+Legislation&title=energy&searchEnacted=0&extentMatchOnly=0&confersPower=0&blanketAmendment=0&sortAlpha=0&TYPE=QS&PageNumber=1&NavFrom=0&parentActiveTextDocId=3540328&ActiveTextDocId=3540342&filesize=892*

[38] *http://www.opsi.gov.uk/si/si2008/uksi_20080225_en_1*

[39] *https://www.og.decc.gov.uk/information/bb_updates/chapters/reserves_index.htm*

[40] *https://www.og.decc.gov.uk/upstream/field_development/2009ReservesField.xls*

- cumulative recovery of oil, condensate, NGL and sales gas to date;
- future production profiles per year for oil, condensate, NGL and sales gas;
- likely year end of field life;
- likely start date, production rates and length of field life for fields for which there is not sufficient detail to provide a year be year production breakdown; and
- reasons for which fields have not yet gained development approval.

Reserve Meetings are conducted with companies during February and March to discuss the data. The reserves forms can be supplied in field units or metric units according to the preference of the operator and are pre-populated with data from the previous year so that DECC can focus on changes to estimated ultimate recovery.

Of note, DECC does not specify to operators how they should prepare their figures. In particular, DECC do not specify a future oil or gas price to be assumed, although they do try to get a feel for what a company has used in the meetings conducted in February and March. In the past DECC have sometimes adjusted operators "proven" numbers for their internal calculations if these were prepared as per the United States SEC rules (in particular at end 2008 with the unusually low end of year oil price). DECC notes that this should be less of an issue moving forward with the changes to the SEC rules commencing from 1 January 2010 which will see prices averaged over a 12-month period.

There is no standard form sent to operators for the collection of contingent resources ("potential additional resources" under the UK definitions). DECC circulates a brief summary for each undeveloped discovery with no plans for development in the next five years prior to the annual reserve and resource meeting. The operators can then comment on whether the information requires updating. DECC tries to obtain minimum, central estimates and upper case estimates from the operators. This could be P90, P50, P10 or best technical estimates. DECC also look for a brief summary of the discovery, including any plans for future development or barriers to any development.

Information for prospective resources is collected from companies using License Application documents, bi-annual Fallow Acreage Reviews and Licence Relinquishment Reports. In addition to the company data on leads, DECC also has a database of internally mapped leads which also contributes to DECC's total estimates of prospective resources.

In Licence Rounds DECC asks for undiscovered resource data at https://www.og.decc.gov.uk/upstream/licensing/26_rnd/how_to_apply.htm where in the technical guidance section they ask for: "the identity and analysis of new play concepts, leads and/or prospects in the acreage, together with predicted reservoir performance and reserve information (including risk/chance of success); also, include appropriate consideration of potential commercial, infrastructure and outline economic analysis if existing discoveries and/or potential re-developments are being considered for further appraisal or development".

Additional information is obtained from Relinquishment Reports. These contain examples of leads, with varying amounts of risk and volumetric data. Where data is incomplete, DECC uses its own fairway risks and knowledge from wells, seismic and other leads in the area to fill in the gaps. DECC also undertakes its own quality control checks of as many as possible of the company leads to make a standardised view on risk plus a judgement on the lead validity.

Publicly available information

DECC publishes proven, probable, proven + probable, possible (i.e P90, P50 and P10) and maximum (the sum of P90, P50 and P10) reserves for oil and gas.
On reviewing the data received by the operator, DECC also comes to a view on all contingent resources and publishes aggregated 1C, 2C and 3C figures for oil and gas[41]. These are then further broken down by region.[42]

DECC also publishes estimates of undiscovered recoverable resources[43]. Many of these estimates are derived internally, with an examination of potential resources in mapped leads. In areas where detailed mapping has been carried out, mapped leads are analysed by standard statistical techniques to obtain estimates of resources in each basin. Geological risk is assigned by play and also to each individual lead. For each geological basin, the risk factors are calibrated to drilling results.

In earlier years, only leads mapped by DECC were used to generate estimates of undiscovered resources. Since end 2003, leads and prospects mapped by oil companies have been added. These are mainly extracted from Licence Round application documents and Fallow Block submissions. The mapping done by DECC does not cover the entire UK continental shelf systematically and company data have provided valuable additional information, particularly in the mature licensed areas where DECC mapped leads and prospects are relatively sparse.

Examples of DECC leads can be seen on its website at https://www.og.decc.gov.uk/UKpromote/index.htm in the sections on “North Sea Opportunities” and “West of Britain Opportunities”. In addition, many Relinquishment Reports are available on the DECC website at https://www.og.decc.gov.uk/UKpromote/relinqs/UKPrelinqs.htm.

United States

Legislative framework

The Federal Energy Administration Act 1974[44] (P.L. 93-275), as amended, created the Federal Energy Administration (**FEA**) and mandated it to collect, assemble, evaluate, and analyse energy information; provide energy information and projections to the Federal Government, State Governments, and the public; and provide Congress with an annual report summarizing these activities. It also provided FEA with data collection enforcement authority for gathering data from energy producing and consuming firms.

Article 790 of the Federal Administration Act established an Office of Energy Information and Analysis (the **Office**), while Article 790A established a National Energy Information System to be operated by the Office. This Office became the Energy Information Administration (**EIA**) following passage of the Department of Energy Organization Act 1977 (P.L. 95-91).

[41] *https://www.og.decc.gov.uk/information/bb_updates/chapters/Table4_5.htm*

[42] *https://www.og.decc.gov.uk/information/bb_updates/chapters/Chart4_5.pdf*

[43] *https://www.og.decc.gov.uk/information/bb_updates/chapters/Table4_6.htm*

[44] *http://uscode.house.gov/download/pls/15C16B.txt*

Reporting requirements

Under the powers in the Federal Energy Administration Act 1974, the EIA undertakes an annual survey of domestic oil and gas reserves. There are two forms that companies fill in: form EIA-23L for large and intermediate operators[45] and form EIA-23S for small operators[46]. Companies are required to report proved reserves (i.e. P90 or 1P reserves) for crude, condensate and natural gas by geographic subdivision, alongside production data and any revisions on previous data.

Instructions accompany the forms sent to companies[47]. Key features of EIA requirements include:

a) The broad definition of "proved reserves" is very similar to that used by the Petroleum Resources Management System. Proved reserves are defined as "the estimated quantities of oil and/or gas, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under current economic and operating conditions." Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations. The area of an oil reservoir considered proved includes:
   1. that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and
   2. the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data.

   In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

   Volumes of crude oil placed in underground storage are not considered proved reserves.

   Reserves of crude oil which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

   Estimates of proved crude oil reserves do not include the following:
   1. oil that may become available from known reservoirs in the future;
   2. natural gas liquids (including lease condensate);
   3. oil, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors;
   4. oil that may occur in undrilled prospects; and
   5. oil that may be recovered from oil shales, coal, Gilsonite and other such sources. It is not necessary that production, gathering or transportation facilities are installed or operative for a reservoir to be considered proved.

   It is not necessary that production, gathering or transportation facilities are installed or operative for a reservoir to be considered proved.

[45] http://www.eia.doe.gov/pub/oil_gas/natural_gas/survey_forms/eia23lf.pdf

[46] http://www.eia.doe.gov/pub/oil_gas/natural_gas/survey_forms/eia23sf.pdf

[47] http://www.eia.doe.gov/pub/oil_gas/natural_gas/survey_forms/eia23li.pdf

For natural gas reserves the same definition applies but it is specified that for natural gas, wet after lease separation, an appropriate reduction in the reservoir gas volume must be made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities and the exclusion of non hydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

b) The reporting obligation falls on the operator of the field.
c) Reserves information is considered confidential and is not published on a field by field basis.
d) Penalties for non compliance may be up to US$ 2,750 a day for each violation, or a fine of not more than US$ 5,000 a day for each wilful violation.

Publicly available information

Proved reserve information is published on the EIA website annually and can be found at http://tonto.eia.doe.gov/dnav/ng/ng_enr_top.asp for natural gas and at http://tonto.eia.doe.gov/dnav/pet/pet_crd_top.asp for crude oil.

The EIA reports a detailed breakdown of all the adjustments in reported reserves including:

1. Revision increases;
2. Revision decreases;
3. Reserves sales;
4. Reserves acquisitions;
5. Reserves extensions;
6. New field discoveries;
7. Discoveries in old fields; and
8. Production

In addition to this proved reserve information, the United States Geological Survey publishes periodic assessments of the potential for undiscovered oil and natural gas endowments of the United States. Assessments for prospective resources for conventional and unconventional oil, natural gas (including coal bed methane) and natural gas liquids can be found at: http://certmapper.cr.usgs.gov/data/noga00/natl/tabular/2008/summary_08.pdf for the onshore United States and at: http://energy.er.usgs.gov/regional_studies/gulf_coast/gulf_coast_assessment.html for the US Gulf Coast.