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EP 2001-1100

Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

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Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

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KEYWORDS

Resource Volumes, Guidelines, Reserves, FASB, SEC

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1. INTRODUCTION

Petroleum resources represent a significant part of the company's upstream assets and are the foundation of most of its current and future upstream activities. Reserves replacement is the basis for a sustainable EP Business. The current status and changes in petroleum resources, and specifically the commercially recoverable portion (reserves), are a significant concern to Group Management. The future of the Group depends on our effectiveness in maturing resources to the point where maximum economic value is realised. To aid in understanding, planning, and decision making about these petroleum resources, resource volumes are classified according to the maturity or status of their associated development activities.

Shell Group wide petroleum resource volumes are reported annually to ExCom and are essential information for the strategic planning process of the EP business. The current status and changes to the proved and proved developed reserves are also published in the Group's Annual Report and 20-F submitted to the Securities and Exchange Commission (SEC). Reserves also form a key component of evaluation of company performance by financial analysts. Therefore the importance of these figures cannot be overemphasised. Reliability, uniformity, consistency, transparency and auditability are essential elements in the collation of petroleum resource reports by Operating Units (OUs) and New Venture Operations (NVOs).

Key issues are proved reserves replacement and the realisation of maximum value from the total hydrocarbon resource portfolio, by pursuing maturation of resource volumes to developed reserves and ultimately sales. Proved developed reserves have, through depreciation, a direct impact on the financial bottom line and therefore require special attention.

These guidelines serve as a reference for OUs and NVOs in the reserves submission and reporting process and as the standard against which audits will be conducted. The information on the format requirements of internal and external submission is included in the second part of these guidelines (SIEP 2001-1101, Ref. 5d). Submission requirements will be communicated annually in a letter from EP Planning.

The present 2001 version contains a significant number of changes compared to the 2000 edition. These changes address an improvement of the report's readibility, the addition of a chapter on methods of quantifying uncertainty and an expanded text describing the new reserves guidelines introduced in 1998. The changes should be seen as editorial only. No change in the volume of reported reserves is intended or expected. Where text has been changed or added, this is indicated by a line in the margin.

2. RESOURCE VOLUME CLASSIFICATION

2.1 Definition

A petroleum resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located in the company's current exploration and production acreage. If the petroleum resource extends beyond the company's licence area the resource volumes must be divided according to the granted licence boundaries, to take proper account of Group share.

Resource volumes are reported as the quantities of sales product for crude oil, natural gas and natural gas liquids. The corresponding quantities of field recovery should be maintained by the OU (See Appendix 6). The reporting of petroleum resource volumes should further indicate the petroleum type, the reporting units and conditions, and the Group share.

2.2 Reserves and SFR

Resource volumes are tied to the project or activity that develops them and are generally reported by field. The term **reserves** is used for resource volumes associated with a project that is **technically and commercially mature**. Resource volumes that do not meet these criteria are called Scope for Recovery (SFR). Proved reserves are the portion of reserves that is reasonably certain to be produced and which will be reported externally. These distinctions will be discussed in Chapters 3, 5 and 6.

The classification scheme shown in Figure 1 is intended to provide a consistent link between a field's resource volumes and the EP business model, identifying separately those resources that are the focus of the various stages in the development life cycle.

Cumulative Production	Sum of successive Annual Production volumes
Reserves:	Developed Reserves (Proved and Expectation) Undeveloped Reserves (Proved and Expectation)
Discovered Scope for Recovery (SFR):	Commercial SFR by Proved Techniques Commercial SFR by Unproved Techniques Non-Commercial SFR
Undiscovered Scope for Recovery	Undiscovered Commercial SFR
Discovered Initial In Place	

Figure 1: Group Resource Categories

These categories are further explained in this Chapter and their definitions are summarised in Appendix 1.

The cascade model (Figure 2) illustrates the migration of volumes between resource categories during the development life cycle.

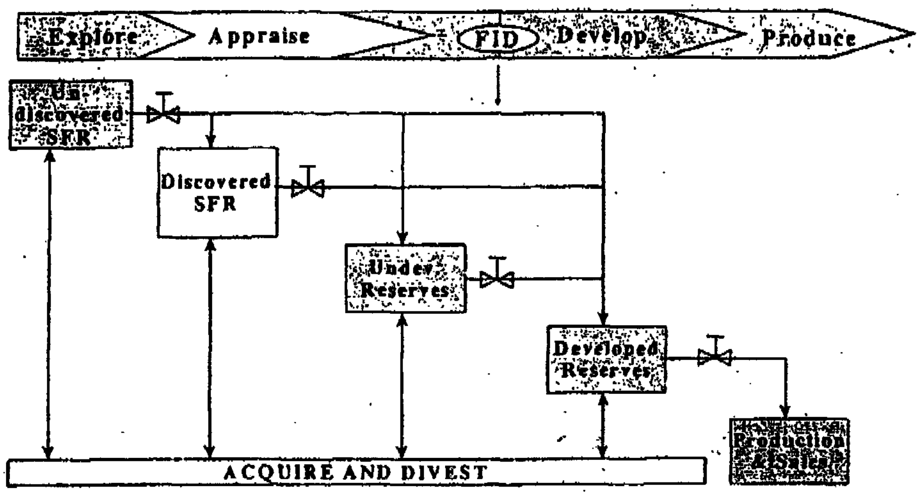

Figure 2: *Cascade Model*

A graphical example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.

2.3 Technical and Commercial Maturity

Resource volumes are realised as production through development projects and/or activities (see below). The classification scheme uses a project's **technical and commercial maturity** as the primary criterion to distinguish between reserves and scope for recovery (SFR). Resource volumes can be classified as reserves only if the associated project that will result in production of those volumes is considered to be technically and commercially mature. If this is not the case, the resource volumes should be classified as SFR. SFR needs a data gathering or other activity (e.g. exploration appraisal, field trial, gas market development, etc) to achieve technical maturity and commercial viability. Secondary technical and commercial distinctions (between proved and unproved techniques SFR and between commercial and non-commercial SFR) further identify resource volumes at various stages in the life cycle.

2.3.1 Project Basis

A project is any proposed or notional modification of the wells, the production facilities and/or the production policy, aimed at changing the company's sales product forecast. It can also be a modification of the company's share in a venture (purchase/ sales-in-place, unitisation, or new terms). The generic term 'project' is also used to describe a group of (sometimes alternative) projects, each with a certain chance of realisation, depending on the results of further data gathering. In that case, the project NPV is replaced by the Expected Monetary Value (or EMV, see Appendix 6).

2.3.2 Technically Mature

For a project to be **technically mature**, information on the resource volume, including its level of uncertainty, is such that a viable project can be defined with an auditable project development plan, based on resource and development scenario descriptions, with drilling/engineering cost estimates, a production forecast and economics. For small projects (e.g. infill drilling in an existing field, or a small satellite development) the plan may be notional or it may be an analogy of other projects based on similar resources. Large or frontier projects, whilst not needing a complete and optimised development plan, must have demonstrated technical and commercial maturity. Successful completion of a Value Assurance Review (VAR) with sufficient definition would support such maturity and robustness. This should preferably be a VAR3 (Concept Selection) review. In all cases, there should be a reasonable expectation that a firm optimal development plan can be matured with time.

2.3.3 Commercially Mature

A commercially mature project is commercially viable over a sufficiently large portion of the range of possible scenarios that reflect the remaining resource uncertainties as well as the remaining commercial uncertainties, including the availability of markets (see below). The definition of what constitutes 'a sufficiently large portion' may vary from case to case but it does require the project NPV for the proved reserves scenario to be positive for appropriate commercial criteria. It is also likely to include an assessment of the capital exposure in case of project failure due to adverse resource realisations. The selected range of scenarios should be documented and auditable.

2.3.4 Market availability

An essential requirement for commercial maturity is also that a market must be available or reasonably expected to be available for the hydrocarbon products. For oil and NGL this means at least the (expected) availability of a pipeline to a shipping terminal or other outlet (e.g. a refinery). For gas this means an expectation that access to a gas market will be available, i.e. the gas must be:

1) contracted to sales; or
2) considered as reasonably certain of being sold based on a reasonable expectation of the availability of markets, along with transportation/ delivery facilities that are in place; or
3) whilst not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing.

For major gas projects critically depending on new gas market capture, reserves booking should in principle be deferred until agreements have been signed, generally at or around project sanction (FID).

The condition of marketability to gas reserves also applies to the NGL products of a non-associated gas project. If the gas market is not matured (or likely to be matured) and the go-ahead of the project is still uncertain, neither the gas reserves nor the NGL reserves can be booked.

2.3.5 Commercially Viable

A scenario is commercially viable if the NPV is expected to be positive under the applicable (or expected) terms and conditions for the acreage and for the current advised Group reference criteria for commerciality.

2.3.6 Economically Viable

A project is economically viable if the expected NPV under the applicable terms and conditions for the acreage exceeds the separately advised Group project screening criteria or if the project has already been approved by shareholders. Projects generally have to demonstrate economic viability in order to obtain investment approval (See Ref. 13).

2.3.7 Important considerations

Full economic viability or formal project approval is not always required for a project to be considered commercially mature and hence for reserves to be booked. Commercially viable reserves may be booked before project approval is sought, but there must be identified activities to improve project economics, the expectation that economic viability will be achieved and a plan to seek approval at some time in the future. The project should also be included in the annual Business Plan. If that intention is not (yet) there (because the project is technically or commercially too immature), the project recoverables must either be booked as SFR or the project / field must be a candidate for divestment. Conversely, if a project is approved and it will go ahead, regardless of (re-evaluated) technical / commercial maturity, the reserves should be booked. An example of this may be a pilot waterflood.

To minimise fluctuations over time, OUs and NVOs should exert caution in transferring volumes between the reserves and SFR categories. Demonstrable technical and commercial maturity will be required when new fields and reservoirs are added to the reserves base. The same requirement applies in principle when undeveloped reserves are retained. To retain developed reserves, their production should have a positive cash generation after subtraction of operating costs, tax and royalties.

Existing volumes that have been classified as reserves, but which are no longer commercially mature, may be retained as reserves only in cases when there is an overriding strategic interest, or where a current small operating loss is expected to be reversed in the short term. In both cases support from shareholders must be obtained.

It is also important to realise that, if project recoverables for a resource are booked as reserves, these must contain both Expectation and Proved volumes, i.e. project volumes should be included in both the Internal and External Reporting submissions. It is not realistic to carry only Expectation and no Proved volumes since that implies that the project is immature and hence that the volumes must be booked as SFR.

Before first time booking of significant reserves in a new area (following exploration discovery, successful acquisition, new gas market capture, reaching project FID, agreeing new contractual terms etc.) it is recommended to review the project with the Centre (EPB-P) to ensure that volumes are supportable and that they would meet external audit requirements.

2.4 Developed, Undeveloped and Total Reserves

Reserves are subdivided in developed and undeveloped reserves. The sum of both is referred to as 'total' reserves.

2.4.1 Developed Reserves

Developed reserves must be producible through currently existing completions, with installed facilities, using existing operating methods. Facilities requiring minor outstanding activities in ongoing projects can be considered as existing if the outstanding capital investment is minor (<10%) compared to the total project cost and if budget approval has been obtained. Volumes behind pipe can only be considered developed if the additional activity (e.g. 'lower' zone abandonment, perforating, stimulating) does not require a full well entry/re-completion and if the cost of this activity (normally opex) does not exceed 10% of the cost of a new well.

Gas volumes in fields where compression is planned or anticipated in future, should only be classed as developed reserves to the extent that they can be produced through the currently existing facilities.

Developed reserves should in principle be estimated through extrapolation of existing well performance trends. This may be done either through plotting (e.g. rate vs. cumulative production, log oil rate vs. time) or through history matched simulation modelling. If no significant history is available to match, the developed reserves will be based on pre-development (simulation) model projections, updated for observed well geological and petrophysical data and well rates. The resulting forecast should represent the production that will be contributed by the existing wells through the currently installed facilities, assuming no future development activity (NFA forecast).

2.4.2 Undeveloped Reserves

Undeveloped reserves require capital investment through future projects (new wells and/or production facilities) in order to be produced. These projects must be technically and commercially mature (Section 2.3). In order to assess commercial viability of these reserves, the wells and activities must be clearly identified, together with their costs.

Gas volumes that require installation of planned or anticipated future compression should be classed as undeveloped until such compression has been installed.

New development projects, which add developed reserves, may defer field/platform abandonment and may thereby also increase the reserves producible from existing completions. Such gains should be included in the economic evaluation of the new development project and should be included in reserves when commercially viable.

Future wells or facilities may accelerate reserves that would otherwise be produced by existing investments. The portion of reserves expected to be accelerated by the new investments should be classified as developed with the existing investments. If future investment accelerates production such that additional reserves are recovered within time limits (e.g. sales contract periods, field life), the additional reserves should be classified as undeveloped until this investment has been made.

2.4.3 Total Reserves

Total reserves are the sum of Develop and Undeveloped reserves. As indicated in the preceding sections, developed and undeveloped reserves should be estimated separately. In particular undeveloped reserves should be based on an identified or identifiable project or projects. Historically, total reserves have sometimes been calculated through multiplication of the STOIIP/GIIP volumes by an assumed or estimated recovery factor, without specific reference to a project. Undeveloped reserves were then calculated as the difference between these total reserves and the separately estimated developed reserves. This practice is in conflict with the concept of project based reserves estimation and should be discontinued.

2.5 Scope for Recovery

Scope for Recovery is the recovery estimate of any notional project, which cannot yet be shown with sufficient confidence to be technically or commercially mature. However, there must be an expectation that this project could mature based on reasonable assumptions about the success of additional data gathering, a maturing technology from current research, relaxation in the market constraints and/or the terms and conditions for implementing such a project.

The economic evaluation should include any future pre-investment costs required to reduce technical uncertainty.

In the case of immature projects, the associated scope for recovery may be reported as a single estimate for the undiscounted average recoveries in the case of success (mean success volume, MSV) together with a probability of success (POS). For aggregation purposes the risked expectation volumes are used (POS*MSV).

2.5.1 Commercial SFR by Proved Techniques

SFR by proved techniques is the volume estimated to be recoverable from discovered resources, by a project utilising a recovery process or technique which has been demonstrated to be technically feasible in the area or in the field. Implementation is expected to be commercially viable, but a wide range of technical uncertainties in the recovery volumes precludes the formulation of a technically mature project proposal.

2.5.2 Commercial SFR by Unproved Techniques

SFR by unproved techniques is the volume believed to be recoverable from discovered resources by a project utilising any recovery technique or process that has been proven elsewhere, but that has not yet been demonstrated to be technically feasible in the area or in the field, and which requires future laboratory tests and field trials (pilot) in order to establish this feasibility. Once technically feasible, the process should be expected to be commercially viable.

Future data gathering may disprove the technique in the field, and with it the possibility of development, and these SFR volumes must therefore be discounted for the risk that the considered technique will not prove to be technically feasible.

2.5.3 Undiscovered Commercial SFR

Undiscovered SFR is the volume believed to be recoverable from as yet undrilled potential accumulations by any process that has been demonstrated to be technically feasible elsewhere, under similar conditions. Development of the accumulation should be expected to be commercially viable.

These SFR volumes must be discounted for the risk that petroleum is not present or is not commercial to develop (Probability of Success, see Appendix 6).

Future data gathering may result in a total write-off of these resources. Following drilling results, the resource volumes are revised and, in the case of a discovery, the economics re-assessed, whereupon the resource is either discarded or reclassified.

2.5.4 Non-Commercial SFR

SFR in discovered resources is considered non-commercial for development projects which, even if technically successful, would not be commercially viable. To avoid unrealistic situations the reporting of Non-Commercial SFR is restricted to projects with a Unit Technical Cost below an annually advised ceiling.

Non-commercial SFR is reported in order to retain an indication of the discovered resources that could become commercial with a change of circumstances (e.g. an increase in oil price, a change in tax regime, development of a gas market, flared/vented/re-injected gas volumes if recoverable and significant enough to be marketed).

2.6 Diagrammatic summary

A diagrammatic summary of the distinction between reserves and SFR is given in figure 3.

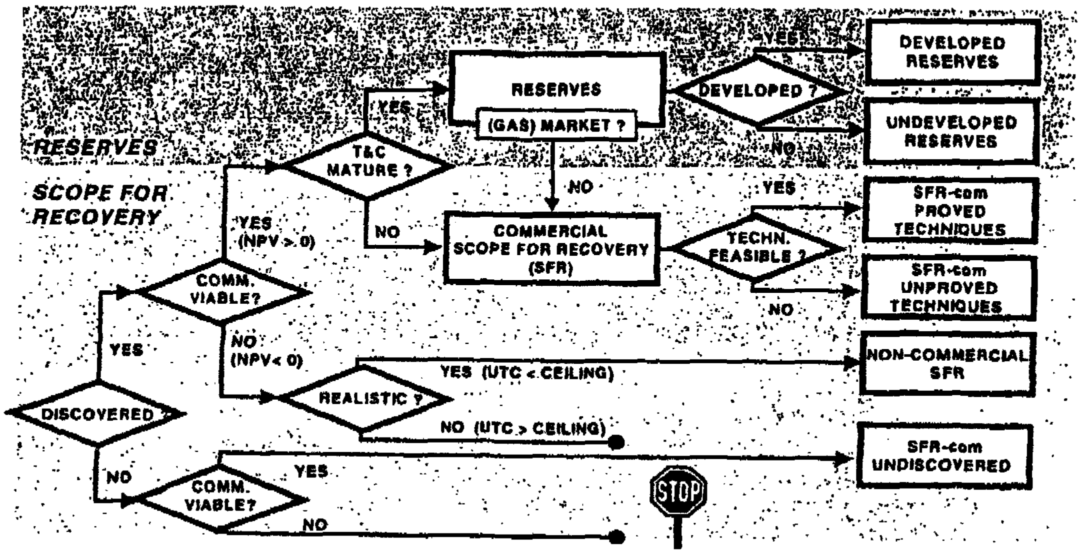

Figure 3: Internal resource classification flow diagram

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3. QUANTIFICATION OF UNCERTAINTY

3.1 Quantification methods

Subsurface resource volume estimates are inherently subject to uncertainty, because they are based on data (from seismic and drilling) and interpretations that contain sometimes significant margins of error. These uncertainties in resource volume estimates can be assessed and represented using a variety of methods. The three most important are:

- The Probabilistic method (P85, Mean, P15)
- The Multi-scenario method (Low, Middle, High)
- The Deterministic method (Proved, Probable, Possible)

3.1.1 The probabilistic method

The probabilistic method has been in use by the Shell Group for more than 30 years. Whilst the Group was initially the only one in the industry applying this method, the method has, over the years, gradually gained wider acceptance, e.g. by the SPE (Ref. 7).

The method consists of assigning probability density functions (PDFs) to each of the constituent parameters that define a subsurface volume estimate (i.e. gross bulk volume, porosity, hydrocarbon fill and saturation, hydrocarbon volume factor, recovery factor). These PDFs are then combined (multiplied) either mathematically ('moment' method, see Ref. 1a - App. 7) or, more commonly, through Monte Carlo simulation. The latter method uses a random number generator which generates random selections from each of the parameter ranges, which are then combined into successive volume estimates, often numbering 1000 or more. Software tools using Monte Carlo simulation are e.g. @RISK, Crystal Ball and FASTRACK.

The resulting product from both the mathematical and the Monte Carlo methods is a PDF or its integral, the cumulative probability function (CPF), which defines the probabilities that the resource volume exceeds each of a range of values. The values associated with the 85% probability the 15% probability are called the 85% and 15% confidence levels or **P85** and **P15** for short. The probability-weighted average value is referred to as the **Mean**. The reason for the original selection of the 85% and 15% intervals by the Group was that they aligned most closely with the previously used distributions of three equi-probable values. More recently, the SPE and some operators and authorities have tended to favour 90% and 10% intervals (P90 and P10 respectively).

The probabilistic method is a good method for assessing the uncertainties of Exploration prospects and sparsely appraised discoveries. For fields that are approaching the development stage it is far inferior to the multi-scenario method and hence not recommended. The main reason for this is that the recovery factor is rarely an independently assessable parameter, but a direct consequence of the combination of static model realisation and development scenario chosen (see below). This can only be represented properly through multiple scenario realisations.

3.1.2 The multi-scenario method

This method is applied when the field has been modelled through a full set of static (geological) and dynamic (reservoir simulation) models. The static model is generally run for a range of possible subsurface realisations, yielding a range of hydrocarbon-in-place volumes. After assigning a probability to each of these realisations, the range of in-place volumes can be represented as a CPF (see above) from which 85%, mean and 15%

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confidence levels can be derived. Representative scenario cases close to these P85, mean and P15 values are then selected and defined as the Low, Middle and High cases respectively.

A representative selection of alternative geological model realisations is converted ('upscaled') into a discrete set of reservoir simulation models, which are then run each for a range of alternative development scenarios (e.g. different well numbers or positions). The alternative development scenarios are not necessarily identical for each geological realisation. The resulting set of model-scenario combinations (usually some 10-20 in number) can again be combined into a CPF, with identifiable P85, mean and P15 values, from which representative Low, Middle and High cases can be selected.

An important characteristic of the multi-scenario method is that it is project- or activity-based, i.e. the recoverable volumes are linked to a specific development plan or plans, with identified (or identifiable) costs, production forecasts and economics. The multiple scenario method is obviously more complex than the probabilistic method, but, with the present range of tools available (notably the GEOCAP – MoReS suite of linkable models) it is seen as a necessary requirement for any field development. It is therefore recommended that in principle all fields with booked reserves (proved and expectation) should use this method.

3.1.3 The deterministic method

The deterministic method has been the method most frequently used by the industry outside Shell. It derives from the original definitions of 'Proved Reserves' as issued by the American Financial Accounting Standards Board (FASB) and by the US Securities and Exchange Commission (SEC) (Refs. 8, 9, 10). These definitions describe the mandatory conditions for reserves that are reported annually through Company reports and public submissions to the SEC. Subsequent definitions for Probable and Possible reserves have been issued by the SPE in co-operation with the WPC (Ref. 7).

Proved reserves are defined as "...the estimated quantities of hydrocarbons which geological and engineering data demonstrate with reasonable certainty to be recoverable...". 'Reasonable certainty' is implied to mean that future reserves revisions are 'much more likely' to be positive than negative. Pivotal in the definition of Proved Reserves is the notion of a 'proved area' of reservoir rock, outside of which no Proved Reserves can be declared. This proved area is constrained by:

- Economic producibility demonstrated by a production test (not a wireline test!),
- Delineated by GOC, OWC, GWC if seen by drilling,
- Oil volumes above OUT levels only if gas is seen updip and a GOC can be interpreted,
- No volumes below 'lowest known hydrocarbons' (LKH), as seen by drilling,
- Laterally confined to one 'legal location' (US regulatory minimum well spacing) away from well control,
- Certainty (not just 'reasonable certainty'!) of continuity of production over the area (must be demonstrated by pressure interference data if beyond one 'legal location'!),
- Improved recovery volumes only with a successful pilot in that specific rock volume,
- The conservative restrictions regarding LKH and lateral well control may be lifted "...upon obtaining sufficient performance history to reasonably conclude that more reserves can be recovered..."

The significant information on reservoir structure and hydrocarbon fill available from modern seismic techniques (DHIs, flat spots etc) is acknowledged by the SEC (Refs. 8, 9), but they maintain insistence on the constraints as stated above.

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The practice in the industry outside Shell has been that Proved reserves estimates are generally 'best estimates', with the proved area constraint being the only conservative element that is strictly adhered to. The important consequence of this has been that Proved reserves as calculated by the deterministic method tended to be lower than probabilistic P85 (or multi-scenario Low) estimates for new discoveries and undeveloped fields. Similarly, they were generally higher for mature, fully appraised fields.

The SPE (Ref. 7) recommend that, if Proved reserves are determined probabilistically, a P90 value be selected. They generally align with the SEC guidance, except that they allow areas beyond the regulatory well spacing to be included if "...data from wells indicate with reasonable certainty (P90!) that the objective formation is laterally continuous and contains commercially recoverable hydrocarbons...".

The SPE/WPC definitions of Probable and Possible reserves (together called Unproved reserves) can be summarised as follows:

Probable reserves:
- 'More likely than not to be recoverable'; P50 if based on probabilistics,
- Probably productive from logs/cores,
- Likely volumes outside the 'proved area', e.g. updip behind interpreted faults,
- Volumes probably recoverable through unproved techniques (no successful pilot yet)

Possible reserves:
- 'Less likely than Probable', P10 if based on probabilistics,
- Hydrocarbon bearing from logs/cores, but possibly not productive
- Possible volumes outside the proved area, e.g. downdip behind interpreted faults,
- Volumes recoverable through unproved techniques, with success in 'reasonable doubt'.

Industry practice tends to be that Probable reserves contain not only volumes associated with areas in the field outside the volumetric confines of the 'proved area', but also volumes associated with projects that have not been fully matured or approved yet.

The sum of Proved and Probable reserves is sometimes regarded as equivalent to the Mean or Middle estimates from probabilistic or multi-scenario methods. Similarly, the sum of Proved, Probable and Possible has been equated to P10 or High reserves. However, the definition for Possible reserves clearly indicates that many of these volumes (and even some Probable reserves volumes) should be classified as SFR in the Shell system.

3.2 Shell Group practice

Shell Group practice has long been based on the probabilistic method as the Group standard for estimating Expectation reserves (for internal reporting) and Proved reserves (for external reporting). Expectation reserves were defined as equal to the mean expected volume and Proved reserves were set equal to the P85 estimate. As a result, the notions of Proved and P85 estimates have long been considered identical to many Group petroleum engineers.

With the increasing maturity of many of the Group's fields it was found that the externally reported Proved reserves were generally more conservative than those reported by the industry. This was confirmed by a Group task force set up in 1998 to compare Group guidelines with industry practice. The recommendation of the task force was to improve the practice of estimating externally reported Proved and Proved developed reserves, particularly for mature fields, in order to make Group estimates more in line with industry practice.

This has led to new Group guidelines setting the framework for annual submissions of internally and externally reported reserves.

The 'proved area' is interpreted to be the area/volume that is defined by:

- Demonstrated producibility through a production test, or log/core data in a tested area,
- Delineated by GOC, OWC, GWC as seen/interpreted from pressures in the reservoir,
- In the absence of 'legal' well spacings, laterally defined by well control and surrounding areas with continuous and good quality seismic amplitudes, but not beyond potentially sealing barriers or faults. Evidence from well drainage limit tests may be used.
- Extended by production performance data, if conclusive,
- Improved recovery volumes supported by a pilot or a conclusive test (section 6.1.4)

The concept of this interpretation is that the drilling and completion of development wells will generally expand the 'proved area' such that its volumetric extent will cover much, if not all of the field. Even if still incomplete at first (i.e. after the first phase of development drilling), this coverage will increase to full coverage with growing field maturity and performance. In line with industry practice, Proved reserves should be based on 'best' or Expectation estimates of 'proved area' volumetrics.

Apart from the volumetric uncertainty, there is the uncertainty regarding reservoir performance (determined by sand development, reservoir continuity, injectant sweep efficiency, aquifer activity, etc.). The latter uncertainty will only be reduced after a sufficiently long period of reservoir production performance. Hence, a cautious, 'reasonably certain' approach should be followed for performance predictions in new fields, whilst for mature fields an estimate much closer to, or equal to the Expectation estimate can be taken, in line with industry practice. An example would be an initial assumption of oil recovery based on depletion only if aquifer influx is not yet certain.

The resulting description of scenario assumptions to be used for estimating Proved and Expectation reserves is given in Fig. 4 and Appendix 4. If reserves (particularly Proved reserves) are still based on probabilistic estimates, these should in principle be consistent with these scenario assumptions.

Expectation Developed and Undeveloped (internal reporting):	All fields	Mean probabilistic or Middle case scenario estimate (Proved+Probable if appropriate and if no Mean or Middle available)
Proved Developed reserves (external reporting):	New, recently developed fields:	'Reasonably certain' scenario (best estimate) of future performance, based on Expectation post-drill 'proved area' volumetrics.
	Mature fields:	Mean or Middle performance projection, based on Expectation fully post-drill + performance based 'proved area' volumetrics. The Proved estimate should in principle be equal to the Expectation estimate.
Proved Undeveloped reserves (external reporting):	Undeveloped fields	'Reasonably certain' scenario (best estimate) of future performance, consistent with pre-drill 'proved area' volumetrics
	New, recently developed fields:	'Reasonaly certain' scenario (best estimate) of future performance, based on Expectation post-drill 'proved area' volumetrics
	Mature fields:	Improved performance estimate, based on observed field performance and Expectation fully post-drill + performance based 'proved area' volumetrics. The Proved estimate should be close to or equal to the Expectation estimate. Lower Proved / Expectation ratios are possible if future activities are significantly different from existing development.

Figure 4: Group recommended practice for estimating Reserves

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3.3 Further considerations

3.3.1 Uncertainty Reduction with Performance

The uncertainty range of ultimate recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. As a field matures, initial in-place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range. Once the reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation (subject to 'proved area' conditions).

Figure 5 illustrates the narrowing of the uncertainty with field appraisal and development. This is a near ideal example where the expectation remains constant for most of the life cycle. This example is also used in Appendix 2 to show the migration of resources between internal and external reporting categories during the field life cycle.

The reduction in uncertainty based on performance should be adequately reflected in the annual reserve and scope for recovery estimates for the field.

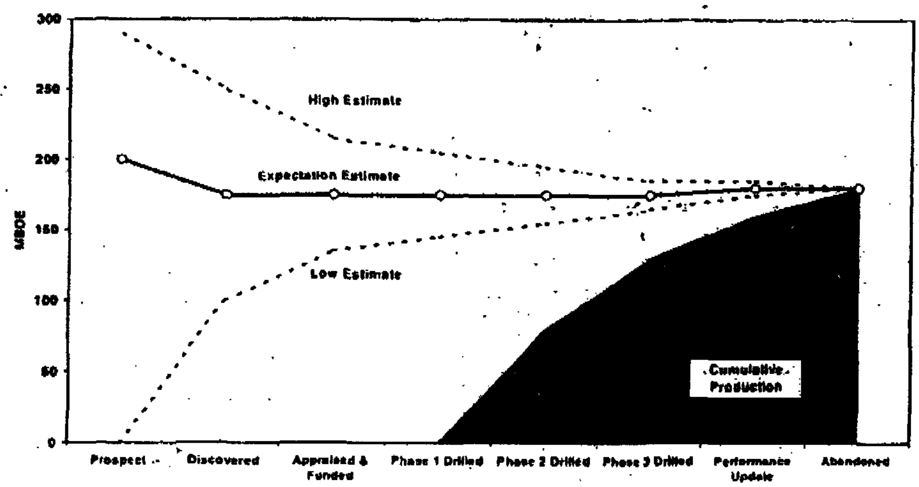

Figure 5: Uncertainty Reduction during the Field Life Cycle

3.3.2 Addition of Proved Reserves Volumes

Proved Reserves volumes are added together at various levels (reservoirs, fields, areas etc) during the resource assessment and reporting process. When Proved reserves are based on P85 or Low estimates, such addition could either be arithmetically or probabilistically. Arithmetical addition usually overstates the uncertainty range for the sum of partially independent volumes (i.e. the resulting sum of P85/Low values is too low), but is appropriate for dependent volumes. Probabilistic addition could be considered for partially independent volumes when the difference with arithmetic addition is significant. An important requirement is, however, that **addition of Proved reserves at or above the level used for financial depreciation calculations must be arithmetical for consistency with financial accounting** (see Section 6.1). Below this level, i.e. normally below the field level, an appropriate selection of the addition method must be made, such that account is taken of dependency between the volumes to truly reflect the aggregated P85/Low/Proved recoverable volume.

Below are two examples where the method of addition is important to handle addition properly.

a) Field A is comprised of separate layers and the properties of these layers are independent of each other. In other words, a low result in one layer would not increase or decrease the chance of a low result in the other layers. Low, expectation and high estimates are calculated for each layer separately. Probabilistic addition should be used to account for the reduced uncertainty of adding together independent volumes. Arithmetical addition of these estimates would understate the low estimate and overstate the high estimate of the total field.

b) A project develops three independent fields as sub-sea satellites connected to one platform. In this case, the investment in surface facilities may be totalled for depreciation[1] and consequently the reserves estimates should relate to the combined fields. Probabilistic addition should be used to calculate the total reserves associated with the platform.

Careful consideration should be given to Commercial SFR by proved techniques where eventual development is only incremental to an existing or planned development. These volumes may have a probability of success (POS) less than one, but with probabilistic addition will contribute at all levels - low, expectation and high - of reserves estimates. Examples of where this would apply are:

1) A fault block that is not yet tested and may be reasonably interpreted as an extension of the delineated area of the field. The project itself is technically and commercially mature. The untested block would be developed through existing field facilities without significant additional investment other than additional wells, which is recognised in the project scope. The uncertainty is geological and volumes are classed as reserves.

2) A phased development where there is uncertainty in the scope (e.g. number of wells) of a project due to geological uncertainty. However, the nature of the project remains essentially unchanged and additional wells could be accommodated within the flexibility of the field facilities design, then the whole range of recoverable volumes should be considered in deriving reserves. A scenario tree can be developed to represent the range of outcomes, both in recovered volumes and optimised number of wells, dependent on geological uncertainty. The uncertainty is resolved, with time, through planned data gathering eventually determining the number of wells. Hence the volumes can be regarded as technically mature. If one branch of the scenario tree is not economic, then the volumes associated with that arm do not contribute to reserves.

If probabilistic addition is used, it should be ensured that the used methodology and parameters are documented in the audit trail.

[1] Group Accounts should be consulted when considering combining surface facilities for different fields for depreciation purposes.

4. GROUP SHARE

Only the Group share of resource volumes is reported, both in submissions for internal and for external reporting. The Group share is determined by three factors: (1) the contractual share of produced hydrocarbons, as agreed with the resource holders (usually the host government), (2) the Group share in the OU or venture that holds the contractual share, and (3) licence duration and other restrictions.

4.1 Contractual Share

Resource volumes can be distinguished according to three different types of agreement: Equity, PSC and 'New Contracts'. These are described below.

If an OU/NVO has interests in several licence areas subject to different contract types, a separate submission must be made with respect to proved reserves for each of the contract types. This applies in particular to submissions for external reporting, in line with FASB requirements (see Chapter 6).

4.1.1 Equity

Equity resources are the OU Company share of resources in Concessions. Concession agreements lay down the general terms and conditions of operation, define the applicable tax rules, the Company share of resources in Concessions and the duration of the production licence. These agreements are generally with the host government, but in the USA they may also be with the private owners of the mineral rights ("lease or fee" conveyance of rights to the operator).

4.1.2 PSC Entitlement

Entitlement resources are the OU Company share of production in acreage governed by a Production Sharing Contract (PSC). The Company entitlement share of production is the Company interest in the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms. The entitlement share is calculated from economic modelling reflecting current estimates of future costs.

4.1.3 New Contracts

In recent years, a number of resource holding countries have introduced innovative production contracts in order to attract investment by foreign oil companies while preserving the principle of national resource ownership. These agreements typically provide for the contractor to recover costs and profits from hydrocarbon revenues while holding no title to, or entitlement to receive petroleum resources.

US Financial Accounting Standards Board (FASB) regulations have lagged behind these developments and provide little explicit guidance on reserves disclosure when the risks and rewards of ownership are carried without legal title to mineral rights.

However, volumes covered by such innovative contracts should be included in external reports in an informative way to be consistent with the spirit of the SEC regulations. The volumes from which economic benefit is derived should be reported if all three of the following conditions are met:

1. The OU Company participates in the production operations as either operator or in partnership with the operator, and so bears a share of the costs and risks of the production operations.

2. The OU Company derives future economic value that is directly related to the volume of hydrocarbons produced. For example, a fee expressed as a fixed or indexed amount per barrel of production would constitute a derivation of value from the produced hydrocarbons, but an operating fee that is largely independent of production would not. The actual source of revenues used to pay the OU is not crucial to this point. For example, if the remuneration is determined by a produced gas volume but paid from oil revenues, the economic value to the OU is in effect derived from the produced gas, and this volume should be reported.

3. The OU Company is exposed to the normal risks and rewards associated with ownership of mineral rights, including the downside and upside from changes in the value of future production volumes. These include the risk that costs may not be recovered, due to either uncertainty as to the presence or magnitude of hydrocarbon volumes or to movements in petroleum prices.

OUs and NVOs working under such contracts should complete the standard resource volume submission for the Group/Company interest in these volumes, noting the nature of the interest. Group share of production is calculated from economic modelling of total financial reward in line with contract terms versus total revenues. Reported volumes should be in line with the reporting of traditional reserves with regard to royalties and should therefore reflect the volumes from which pre-tax cash flow is derived. As elsewhere, cash royalties are regarded as a production cost (see below).

When an OU is participating in a venture which grants neither title to, nor an entitlement to receive petroleum, and which does not satisfy the three criteria above the OU should not report reserves or production volumes. For example this might occur if the recovery of costs is guaranteed against adverse price movements or a shortfall in recovered volumes.

4.2 Group Share in OU

If the Group holds only a partial share (i.e. less than a 100% share) in the company or entity that holds the concession or contractual share with the resource owners, this share must also be accounted for in the reserves submission.

As an exception to this, both Expectation and Proved reserves (internal and external reporting respectively) are reported on a 100% basis for companies in which the Group holds a controlling (>50%) interest, in line with financial reporting. Minority interest volumes included in these total reserves are then disclosed separately. Prior agreement must be obtained from Group Finance before such reporting is considered.

4.3 Licence duration and other restrictions

4.3.1 Licence or Contract Extensions

<u>For internal reporting purposes</u>, Group shares of the expectation estimates of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the relinquishment date, that is not (yet) covered by a right to extend or by a letter of assurance (see below). The currently existing licence terms or other anticipated terms should be assumed for this extrapolation. In addition to these full life cycle volumes, resource volumes are also recorded as limited to the current licence or its agreed extension only (total expectation reserves, developed expectation reserves and total commercial scope for recovery).

<u>For external reporting</u>, Group share of reserves (proved, proved developed) is limited to future production within the existing licence or contract period. However, production

beyond the licence or contract period can be included if there is a legal right to extend a production licence or PSC, or if the government has formally indicated that it will favour substantiated requests for extensions in the future (letter of assurance). In that case, volumes recoverable during the extension period are included in the Group share, assuming currently existing or other anticipated terms. Such considerations should be documented in the annual submission.

In some countries, the issue or duration of production licences for gas fields is effectively coupled to the conclusion of gas sales contracts. In other areas, a realistic target date for initiation must be set for projects that are not yet firmly planned so that the production forecast and other screening assumptions can be used to estimate the volume produced before licence or contract expiry.

4.3.2 Long Term Supply Agreements

FASB regulations (Ref. 10, 69 par. 13) require that quantities of oil or gas subject to purchase under long term supply, purchase or similar agreements should be reported separately, if the OU participates in the operation of the properties in which the oil or gas is located or otherwise serves as the "producer" of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.

The "supply" agreement should be a consequence of the OU acting as producer. This would not be the case if, for example, others had similar agreements but did not participate in the production operations.

These net quantities, as well as the net quantities received under the agreement during the year, should be included in the end year estimate of reserve volumes for external disclosure form.

4.3.3 Royalty

Outside the USA, Royalty is a payment made to the host government for the production of mineral resources. It is usually calculated as a percentage of revenues (payable in cash) or production (payable in kind).

Where in practice royalty obligations are met in kind (i.e. by delivering oil instead of cash), the Group share of production and reserves should be reported **excluding** these volumes.

Where royalty is payable in cash or is in principle payable in kind but the government has formally elected to receive, or customarily receives, payment in cash, Group share of production and reserves should be reported **including** these equivalent royalty volumes.

Within the USA, Royalties are payable to the owner of the mineral rights, who can either be a private or a public entity (e.g. State government). In line with SEC regulations, these are always **excluded** from Group reserves whether paid in cash or in kind, for US properties.

4.3.4 Over-Riding Royalty

In the USA, there are often 'Overriding Royalties' payable to the owner of mineral rights or third parties. These shares of reserves are **excluded** from Group reserves. Third party overriding Royalties payable to Shell are **included** in Group reserves.

4.3.5 Volumes flared/vented and own use

Group share volumes must **exclude** any volumes flared/vented and 'own use' (fuel for production facilities, compressors etc) in the **upstream** operations prior to transfer of the

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volumes to the buyer (Third Party' or 'Downstream'). This is consistent with the definitions applied for e.g. Gas Production available for Sales from own reserves (GPafS), as applied in the Ceres production submissions through the Finance system (see GFIM ref. 11).

4.3.6 *Fees in kind*

Third Parties may in some cases pay Fees in Kind or Tariff in Kind (TIK) for the use of infrastructure (e.g. pipeline tariff, processing fee). Such volumes received by the company (to the extent that they originate from non-Group owned resources) do not constitute a Group share in resources and should be excluded from reported volumes. Condensate volumes recovered from a pipeline system related to transportation of Third Party gas volumes and sold by the company are equivalent to fees-in-kind received. All fees-in-kind received should be included as a purchased volume in the company accounts.

Where a company pays fees in kind (from its own fields/resources) to a Third Party, these do constitute a Group share in resources and should be included in the reported volumes. Annual volumes produced and used as fees in kind should be included in sales volumes, with associated revenues (at an agreed or fair market value) equivalent to booking of the incurred operating cost.

4.3.7 *Under/Over Lift*

Group share should also allow for any historic under or over lift by partners or government. A Group historic over lift should be reflected as an equivalent reduction of Group reserves, a Group historic under lift as an equivalent increase of Group reserves.

Group share should reflect impact of swap deals between fields where early production capacity in one is traded versus later production repayment by the other.

Treatment of take-or-pay volumes should be aligned with financial treatment of the cash received and booking of production volumes.

4.3.8 *Open Acreage*

Group share of volumes is non-existent in open acreage and acreage for possible acquisition or farm-in.

4.3.9 *Committed Gas Reserves*

Total volumes of expectation gas reserves within licence, which have been sold (committed) under long and short term contractual agreements. In countries with a mature/deregulated gas market all gas reserves, which have a near certainty of market take-up can be classified as 'committed'.

4.3.10 *Committable Gas Reserves*

Volumes of gas reserves, which have not been sold, but could be sold (committable) under contractual agreements. The sum of committed and committable gas reserves should equal expectation gas reserves within licence. Gas resource volumes, which are classified as scope for recovery due to lack market availability, should not be included.

4.3.11 *Gas Re-injection*

Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservation, Underground Gas Storage (UGS, including cushion gas), or other reasons, without transfer of ownership, remain part of a company's resource base and should be included in the Group resource estimates. These gas volumes should be classified and reported as reserves or SFR, depending on the recovery anticipated through future developments (e.g. taking into account anticipated re-saturation losses).

Gas volumes re-injected in an UGS project on behalf of a Third Party (following transfer of ownership by the company to this party) do not constitute a Group share in resources and should be excluded from reported volumes.

4.3.1.2 *Oil Sands*

Petroleum volumes (heavy oil, bitumen, syncrude, gas, liquids, etc.) recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a "manufacturing" process must be reported separately from the conventional resource base. This should also include conventional reservoirs where recovery occurs through a mining operation. However, conventional reserves or SFR can be claimed for otherwise unconventional reservoirs if the petroleum is recovered in its natural state and original location (i.e., has not been "manufactured" in situ by alteration from natural state) through the use of conventional methods (wells). Examples of this are coal bed methane produced from wells or heavy oil produced from wells using conventional thermal recovery methods. (Also see SEC definitions, Appendix 3 C4.)

5. RESOURCE VOLUMES FOR INTERNAL REPORTING (EXPECTATION RESERVES AND SFR)

The reported volumes must comply with the Shell Group guidelines contained in this report. Only the Group share of expectation reserves, SFR and production (sales volumes) is reported (Chapter 4).

5.1 Expectation Reserves

Reserves are the sales quantities anticipated to be produced and monetised from a discovered field associated through project(s) that is/are **technically and commercially mature** (see Section 2.3). Petroleum volumes must have been demonstrated to be producible through wells from the field.

A market must reasonably be expected to be available for the hydrocarbons, particularly for gas reserves (Section 2.3.4).

The production forecast, and therefore the reserves, must be cut off at the point where cash generation becomes negative, i.e. when operating costs (with appropriate treatment of abandonment costs) exceed sales revenues after royalties. If the remaining tail production is significant, it may be booked as Non-Commercial SFR (see below).

Production forecasts should reflect volumes available for sale taking into account all system constraints, abandonment timing, expected operational performance (planned and unplanned deferment), production quota restrictions, contractual sales volumes, market and other expected production limitations (community disturbance etc.).

The historical production and production forecasts (i.e. reserves) must be adjusted for any volumes flared/vented and 'own use' (see Section 4.3.5).

5.1.1 Expectation Developed Reserves

Developed reserves must be producible through existing completions and facilities, using existing operating methods. Volumes behind pipe can only be considered developed if the completion activities' cost does not exceed 10% of the cost of a new well. See section 2.4.1.

Developed reserves should in principle be estimated through extrapolation of existing well performance trends. The resulting forecast should represent the production that will be contributed by the existing wells through the currently installed facilities, assuming no future development activity (NFA forecast). For the full conditions, see Section 2.4.1.

5.1.2 Expectation Undeveloped Reserves

Undeveloped reserves require capital investment in future projects, which must be technically and commercially mature (Section 2.3). In order to assess commercial viability of these reserves, the wells and activities must be clearly identified, together with their costs.

For a more extensive description see Section 2.4.2.

5.2 Scope for Recovery

Scope for Recovery is the recovery estimate of any notional project, which cannot yet be shown with sufficient confidence to be technically or commercially mature (see section 2.5).

The economic evaluation should include any future pre-investment costs required to reduce technical uncertainty.

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In the case of immature projects, the associated scope for recovery may be reported as a single estimate for the undiscounted average recoveries in the case of success (mean success volume, MSV) together with a probability of success (POS). For aggregation purposes the risked expectation volumes are used (POS*MSV).

Scope for Recovery is subdivided into four distinct categories: Commercial SFR by proved techniques, Commercial SFR by unproved techniques, Undiscoverd commercial SFR and Non-commercial SFR. Details are given in section 2.5.

The volumes reported for the four SFR resource categories are based on **full life cycle**, i.e. without consideration of production licence expiry. In addition, total Commercial SFR within licence should also be reported.

5.3 Annual and Cumulative Production

Annual sales volumes are reported both through the annual reserves submissions and through the Finance system (Ceres). Both submissions find their separate ways into the Group Annual Report and consistency is of utmost importance. Production Operations and Finance functions must reconcile their figures prior to any submission. Annual oil/NGL production [Ceres line 0933] and Gas Production available for Sales from own reserves (GPafS) [Ceres line 9130] as reported in the upstream sector in Ceres **must equal** the volumes reported in the annual resource statement using the appropriate unit conversion factors. The definition for gas reserves and the definition for Gas Production available for Sale (see GFIM ref. 11) are fully aligned (both excluding flare/vent and own use).

The resource volume category 'Cumulative Production' pertains to summation of the annually reported yearly sales quantities of production volumes up to the date of reporting. Separate records must be kept of both annual Group share and full field produced volumes if the Group share percentage has changed over the years.

5.4 Volumes Initially In Place

The petroleum volume Initially In Place (IIP) is expressed in volumes of Stock Tank Oil Initially In Place (STOIIP), Condensate Initially In Place (CIIP) and Gas Initially In Place (GIIP) under standard conditions. For standard conditions the same PVT data must be used as adopted for the reporting of field recoveries.

It is necessary to maintain records of both the full field and the current Group share in-place volumes if ownership percentage of the properties has changed or is likely to change over the years.

6. RESOURCE VOLUMES FOR EXTERNAL REPORTING (PROVED RESERVES)

6.1 Proved Reserves

Proved Reserves are defined as those reserves that are reported externally in the Group Annual Report and through annual submissions to the SEC. A clear distinction is made between these externally reported Proved reserves and internally maintained P85 or Low volumes. This is explained in Chapter 3, in particular Section 3.2. Only the Group share of Proved reserves (sales volumes) is reported (Chapter 4).

Externally reported reserves volumes serve two important purposes – financial accounting and investor assessment. Financial accounting generally uses Proved developed reserves to calculate the depreciation of EP Business capital investments (GFIM, Ref. 11). The amount of depreciation affects the Group's book earnings, which are also externally reported. Shareholders and the investment community use the reported volumes and earnings to assess the performance and value of the company. It is therefore essential that externally reported proved reserves volumes are a true reflection of shareholder value.

Proved developed and Proved total (developed+undeveloped) reserves and annual production are reported for oil, gas and NGL sales quantities as at the 1st of January of each year. The reported volumes must comply with the Shell Group guidelines for reserves as contained in this report (summarised in Appendix 1). Group guidelines are based on SEC definitions, with some interpretations that have been accepted by external auditors (see section 3.2 and Appendix 4).

Reserves should be based on technically and commercially mature projects (Section 2.3). Only the Group share of proved reserves and production (sales volumes) is reported (Chapter 4). Proved reserves should be reasonably certain to be produced and sold during the remaining period of existing production licences and agreements (Section 4.3.1). Any applicable government restrictions on oil export and contractual or practical market limitations to gas delivery rates should be taken into account.

Proved reserves should be consistent with the 'proved area' as defined by SEC/FASB and interpreted by SIEP (Section 3.2). In cases where there is considerable uncertainty in fluid contacts, the P85 or Low estimate should be compared with the SEC proved area method, e.g. applying the criterion of lowest known hydrocarbon, if not disproved by performance. If the two reserve estimates should be significantly different from each other, a reconciliation should be made by the OU to assure itself that the reported reserves are a true reflection of shareholder value.

Asset holders should be aware of the differences between probabilistic and deterministic techniques (Section 3.1) since third parties, e.g. gas buyers and hence external reserves auditors for certification, may adopt different practices.

6.1.1 Proved Developed Reserves

Developed reserves must be producible through currently existing completions, with installed facilities, using existing operating methods. Volumes behind pipe can only be considered developed if additional activities require only minor future investment not exceeding 10% of the cost of a new well. See Section 2.4.1.

Proved developed reserves should in principle be estimated from extrapolations of existing well performance trends (Section 2.4.1). For recently developed fields, the original pre-development model projections (updated for observed well data and well rates) may be used.

In line with recommended Group practice (Section 3.2), Proved developed reserves in new developed fields should be derived from a 'reasonably certain' scenario (best estimate) of anticipated field production, based on the Expectation (post-drill 'proved area') volumetrics. With increasing cumulative production, the Proved estimate should gradually grow until it equals the Expectation estimate when the field is mature. A mature field is broadly seen to be a field with a maturity ratio (cumulative production divided by expectation ultimate recovery) of 40% or more.

6.1.2 *Proved Undeveloped Reserves*

Undeveloped reserves require capital investment in future projects (new wells and/or production facilities) in order to be produced. These projects must be technically and commercially mature (Section 2.4.2).

Proved undeveloped reserves in undeveloped fields should be based on a 'reasonably certain' scenario of anticipated future performance, consistent with pre-development 'proved area' volumetrics. If probabilistic estimation is used, the P85 value should be consistent with this scenario and volumetrics.

Proved undeveloped reserves in new or recently developed fields should be derived from a 'reasonably certain' scenario (best estimate) of future wells' (and activities') performance, based on the Expectation (initial post-drill 'proved area') volumetrics. With increasing cumulative production through existing wells, the uncertainties regarding the performance of future wells should gradually diminish, such that Proved undeveloped reserves can be taken as equal to Expectation reserves for fully mature fields (broadly with a maturity ratio of 80% or more). However, there may still be uncertainties regarding the future wells that are not addressed by the current wells' performance (e.g. new horizontal wells in a field previously developed through conventional wells), which may require the Proved estimates still to be somewhat conservative.

6.1.3 *External Financing*

For projects which require some degree of external financing (e.g. LNG projects, major new venture start-ups), project financing must be expected to be available before proved reserves are disclosed externally. This could, by exception, be a reason why the reserves of some viable projects are excluded from external reporting.

6.1.4 *Improved Recovery Projects in External Disclosures*

Advances in reservoir modelling techniques have greatly enhanced the systematic assessment of project recoveries across the full range of uncertainties, increasing confidence in the use of simulation results as the basis for investment decisions and reserves estimation. This improved quantification has in some cases shown that pilot testing is not necessary prior to project commitment (based on a Value of Information approach). Under these circumstances, recovery from improved recovery projects (e.g. fluid injection, reservoir blowdown) may be considered Proved when the following three conditions are met:

1) A comprehensive assessment of uncertainties results in confidence that the actual volume will be greater than the low estimate.
2) The main features of the recovery process are supported by confirmed responses in analogous reservoirs.
3) Project financing has been obtained or is expected to be obtained without a pilot testing phase.

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In the case of improved gas recovery, the additional conditions in the following section also apply.

6.1.5 Proved Gas Reserves and market availability

In addition to the foregoing conditions, proved reserves of natural gas should include only quantities falling in the following categories:

1) that are contracted to sales; or
2) that can be considered as reasonably certain of being sold based on a reasonable expectation of the availability of markets, along with transportation/ delivery facilities that are in place; or
3) that, whilst not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing.

These restrictions also apply to the external disclosure of condensate/NGL products that are subject to the go-ahead of a non-associated gas project.

For major gas projects critically depending on new gas market capture, proved reserves booking should generally be postponed until agreements have been signed, generally at or around project sanction (FID).

6.1.6 Proved Reserves vs Expectation Reserves Forecasts

The development scenarios (in particular the timings of successive future field developments) for Proved and Expectation reserves do not need to be the same. It is reasonable to assume that whatever forecast has been assumed for the Expectation case can also be met by disappointing (i.e. Proved) reserves realisations in the fields, simply by accelerating their development. This is particularly important in cases where the Expectation forecast is capped by overall production rate constraints or production quota. The resulting Proved forecast will of course decline from plateau earlier than the Expectation forecast, but during initial years they should be the same. This will avoid losing too much proved reserves beyond licence expiry, when applicable.

6.1.7 Types of Agreements

Under US Financial Accounting Standards Board (FASB) regulations, separate disclosure is required for oil and gas volumes applicable to different types of licence or contract agreements, see also section 4.1. These requirements are illustrated in Figure 6.

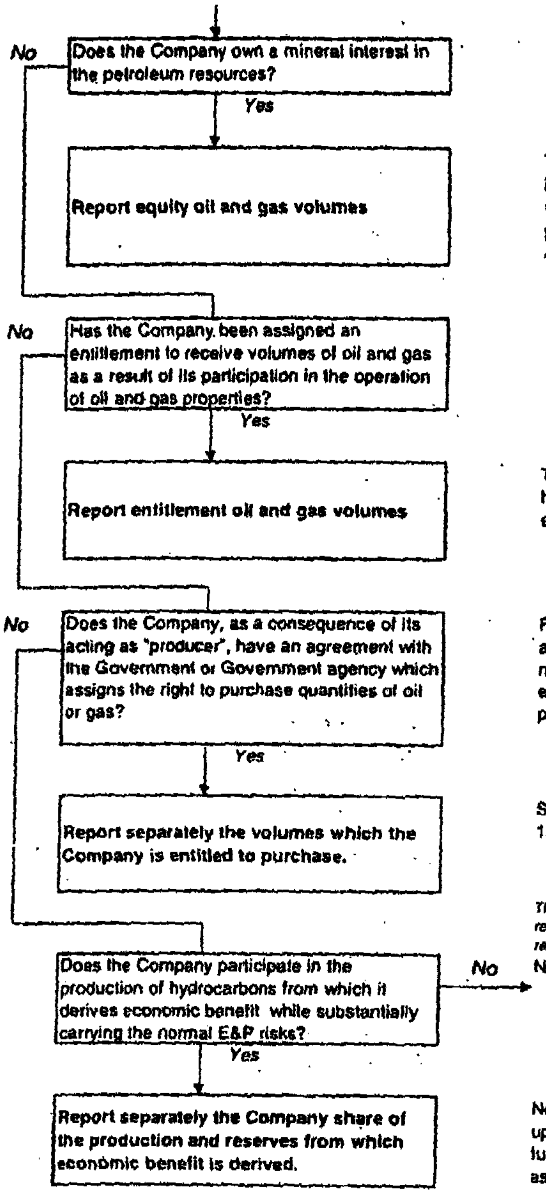
6.1.8 Minority Interest

Reserves are reported on a 100% basis for companies in which the Group holds a controlling interest (in line with financial reporting) rather than on a Group share basis. Minority interest volumes included in the total proved reserves are disclosed separately. Such inclusion of minority interest requires prior agreement with Group Finance. See also section 4.2.

6.2 Annual Production

Annual sales volumes are reported both through the annual reserves submissions and through the Finance system (Ceres). Both submissions find their separate ways into the Group Annual Report and consistency is of utmost importance. Production Operations and Finance functions must reconcile their figures prior to any submission. Annual oil/NGL production [Ceres line 0933] and Gas Production available for Sales from own reserves (GPafS) [Ceres line 9130] as reported in the upstream sector in Ceres must equal the volumes reported in the annual resource statement using the appropriate unit conversion factors. The definition for gas reserves and the definition for Gas Production available for Sale (see GFIM ref. 11) are fully aligned (both excluding flare/vent and own use).

Naturally, the annual sales volumes reported in the opening and closing balances for Proved and Expectation reserves should be identical in both submissions.



Notes

Traditional meaning of an enterprise's interest in reserves (FASB 19 para.10). Exclude volumes payable to others through production payments or carried interests (FASB 19 para. 47a and d).

Typical PSC case. Whether the Government has a pre-emptive right to buy back these entitlements is not material.

Relevant where national legislation prevents access to mineral rights. The agreement would not be a consequence of acting as producer if e.g. others have similar agreements but do not participate in production operations.

Separate disclosure is required. FASB 69 para. 13.

The following are interpretations of the principles of the FASB regulations regarding Company interests in production & reserves:

No volumes reported.

Normal E&P risks refer to both downside and upside exposure to changes in the value of future production volumes due to uncertainties as to their presence, volume and price.

Figure 6: Types of External Disclosures in Relation to FASB Regulations

7. RESOURCE VOLUME MANAGEMENT, REPORTING, RESPONSIBILITIES AND AUDITS

7.1 Value Realisation

The most important objective of resource volume management is the progression of the volumes to the point where maximum value is realised. The main purpose of the internal classification scheme tied to the development life cycle is to enable understanding of the potential value and the actions needed to mature volumes. In order to achieve business growth and reserves replacement objectives, it is essential that OUs and NVOs have efficient systems to move volumes through the value chain from scope for recovery to production and sales as shown in the cascade model.

OUs and NVOs internal reserve management systems should:

a) Set targets and monitor actual performance in maturing volumes towards value realisation,

b) Fully inventorise and have maturation plans for Scope for Recovery opportunities,

c) Regularly (annually) review ultimate recovery targets for existing fields and identify what activity - appraisal, study, new technology development, commercial agreement, etc. - is required to reach these targets,

d) Have Key Performance Indicators (KPI's) to measure performance (e.g. reserves replacement ratio, scope for recovery maturation ratio, time between discovery and first production).

7.2 Shareholder Requirements

EP Planning will communicate each year to OUs and NVOs a timetable and details about submission requirements for both internal and external reporting.

Volumes will be reported based on the classification systems described in this report. Additional information is reported for the calculation of the Standardized Measure required by the US Financial Accounting Standards Board (FASB).

7.3 Methods and Systems

OUs and NVOs are responsible for selecting the methods and systems that are technically most appropriate for quantifying the resource volumes of their assets consistent with these guidelines. The preferred methods and systems may vary depending on the type of resource and with time as the resource matures and technology improves.

A variety of commonly used Group and 3rd party systems are available to support resource volume assessment. Group systems are tailored to these requirements and methods and will generally provide an inherent level of quality assurance through input constraints, internal calibrations, and other 'reality checks'. Where more generalised 3rd party systems are used, OU and RBD management should be aware of the greater burden of quality control that will be required.

The Group Reserves Auditor will review decisions on methods and systems during the periodic audits. As far as these methods have an impact on the estimation of externally reported resource volumes, the Group Reserves Auditor will ensure that recommended methods are acceptable to the external auditors.

In some cases, OUs and NVOs may be unable to follow Group guidelines and/or recommended practice, due to government requirements, hardware constraints or other reasons. It is the responsibility of the OU Reserves Custodian to bring such cases to the attention of the Group Reserves Auditor, to enable him to obtain external auditors' approval of the OUs and NVOs specific methods and systems.

7.4 Responsibilities and Audit Requirements

7.4.1 EP Planning Responsibilities

EP Planning is responsible for compilation of the Group statistics of resource volumes, the analysis thereof and the communication to other functions. EP Planning also maintains the resource volume guidelines.

7.4.2 Reserves Auditor Responsibilities

The Group Reserves Auditor will carry out regular detailed reserves reviews in OUs and NVOs to ensure compliance with SEC requirements. The Terms of Reference for SEC Audits are included in Appendix 5. The external auditor will verify the Proved reserves data for external reporting.

7.4.3 Operating Unit Responsibilities

Within OUs and NVOs, a Management System should be established (see Reference 6), clearly defining internal reporting requirements, tasks and responsibilities. Technical and Financial functions must co-ordinate and reconcile their figures (particularly production volumes) prior to submission.

All levels in an OU, including Asset managers and the reservoir engineer preparing the individual field reserves estimates, should be aware of the importance of externally reported reserves (Proved, Proved developed) and their impact on financial indicators.

Asset and OU managers are responsible to ensure that the guidelines are implemented in such a way as to best represent to the shareholders the true value of the asset.

7.4.4 Non-operated Reserves

Where Shell is not the operator, the local Shell EP representative should prepare the reserves submission. In this case the Shell representative has the responsibility of ensuring that resource volume assessments by the operator are aligned with Group guidelines before submission. This may include reclassification of volumes between reserves and SFR categories where the operator's criteria differ from Group criteria. As usual, an audit trail (Note for file) should be available to document the reserves estimate.

If there is no EP representative or if the necessary data are not available locally, then the submission is prepared by SIEP (responsible RBA).

7.4.5 Annual Review of Petroleum Resources

Until 1995, the Annual Review of Petroleum Resources (ARPR) was a constituent document of the annual EP Programme Documentation, providing an inventory of the status of petroleum resources. While OUs and NVOs no longer submit ARPR's to SIEP, the compilation of such an overview report will generally be necessary to satisfy the requirements of OU governance and as such will be a key element of the OU reserves Management System referred to above.

7.4.6 Audit Trail

Audit trails form an essential element in the reserves reporting process and are an indispensable tool for the Group Reserves Auditor to assess the quality of the reserves estimates. They should support and document the submitted figures and ensure that OU management understand and own the reserves submissions to SIEP. They also form an essential link in handing over resource estimates between field reservoir engineers and reserves co-ordinators and their successors.

For all the reported resource volumes an audit trail must be available of the assumptions made and processes followed. This will allow any subsequent assessor to modify these estimates based on new information in a reconcilable manner. Thus, evaluation reports must be compiled (preferably on a field basis) giving the basic data, the way it has been interpreted and processed, the development options considered, and the resultant volumes with the assigned probabilities. In addition, a description should be given of the development strategy, including data gathering activities. These reports may be working files (if acceptable to local auditors), but it is recommended to make a duplicate 'for file' in order to ensure that the data are preserved in field reports.

Where subsequent small revisions are made, an update note must be compiled. Multiple changes may be combined in one overall update of the resource volumes if they all belong to the same change category. After several years of small changes or following a development study, a new evaluation report must be issued. When a proposed change has a significant impact on the Company's total reserves or financials, SIEP should be advised at the earliest opportunity.

Guidelines on how to prepare a good audit trail, with suggested formats for tables etc. can be found on the Shell World Web (Reference 12).

REFERENCES

1. EP 88-1140 Part 1, Classification, definitions and reporting requirements,

1a. EP 88-1145 Part 2, Methods and procedures for resource volume estimation, SIPM, April 1988

2. EP93-0075 Petroleum Resource Volume Guidelines, May 1993

3. Revision of Report EP93-0075, 12 August 1994

4. Revision of Report EP93-0075, 10 November 1995

5. Revision of Report SIEP97-1100, September 1997

5a. Revision of Report SIEP98-1100 & 1101, September 1998

5b. Revision of Report SIEP99-1100 & 1101, September 1999/October 1999

5c. Revision of Report SIEP2000-1100 & 1101, September 2000/October 2000

5d Revision of Report SIEP2001-1101, October 2001

6. EP92-0945 Business Process Management Guideline, SIPM, EPO/72, June 1992

7. Petroleum Reserves Definitions, Society of Petroleum Engineers and World Petroleum Congresses, http://www.spe.org/cda/content/0,1085,284,00.html

8. Handbook of SEC Accounting and Disclosure

9. SEC Clarifications to Proved Reserves Definitions, http:/www.sec.gov/divisions/corpfin/guidance/cfactfaq.htm#P279_57537

10. Financial Accounting Standards Board (FASB), e.g. Statements 19, 25 and 69.

11. Group Finance Information Manual - GFIM

12. Shell Wide Web – Resource Management web-page, http://sww.siep.shell.com/epb/epplan/arpr/resmgt.htm

13. Group Project Evaluation and Screening Criteria, June 2001.

APPENDIX 1 RESOURCE CATEGORY (QUICK REFERENCE)'

External Reporting	Internal Reporting	Proved Reserves		Portion of internally reported Expectation reserves (see conditions below), that is 'reasonably certain'. Additional conditions: Restricted by licence periods, government constraints and market limitations. External financing, when used, must be expected to be available. Deterministically estimated volumes should reflect undefined fluid contacts and untested recovery mechanisms ('proved area').
			Proved Developed Reserves	Proved reserves producible through existing completions and installed facilities using existing operation methods. Consistent with 'proved area'. Outstanding project activities considered completed if remaining cost <10% of total. 'Behind pipe' volumes only if cost <10% of well cost.
			Proved Undeveloped Reserves	Proved reserves which require future capital investment (wells and/or facilities). Consistent with 'proved area'. Recovery techniques must be proven 'in the rock volume'.
	Internal Reporting	Expectation Reserves		Project is 'technically and commercially mature'. Must be commercially viable; formal project approval or economic viability not required. Market is reasonably expected to be available. Includes only production with positive cash flow. Not restricted by licence period. Group share only reported.
			Developed Reserves	Reserves producible through existing completions and installed facilities using existing operation methods Outstanding project activities considered completed if remaining cost <10% of total. 'Behind pipe' volumes only if cost <10% of well cost.
			Undeveloped Reserves	Reserves which require capital investment (wells and/or facilities)
		Scope for Recovery		Project is technically or commercially not mature Not restricted by licence period. Group share only reported.
			Commercial SFR by Proved Techniques	Discovered. Commercially viable. Techniques have been proved to be feasible in this resource. A sound technical project proposal is not possible yet due to large range of technical uncertainty and/or due to market unavailability.
			Commercial SFR by Unproved Techniques	Discovered. Commercially viable. Recoverable by techniques that have been successful elsewhere, but cannot yet be demonstrated to be feasible in this field. Laboratory work or trials elsewhere have a reasonable chance of demonstrating feasibility in this field. Discounted for the risk that the considered technique will not prove to be feasible.
			Non-Commercial SFR	Discovered. Not commercially viable even if technically successful. Commercially viable with a change of commercial circumstances. Unit Technical Cost below an annually advised ceiling.
			Undiscovered Commercial SFR	Recovery from undrilled prospects. Commercially viable exploration and development. Techniques have been successful elsewhere under similar conditions. Discounted for the risk that commercial volumes are not present.

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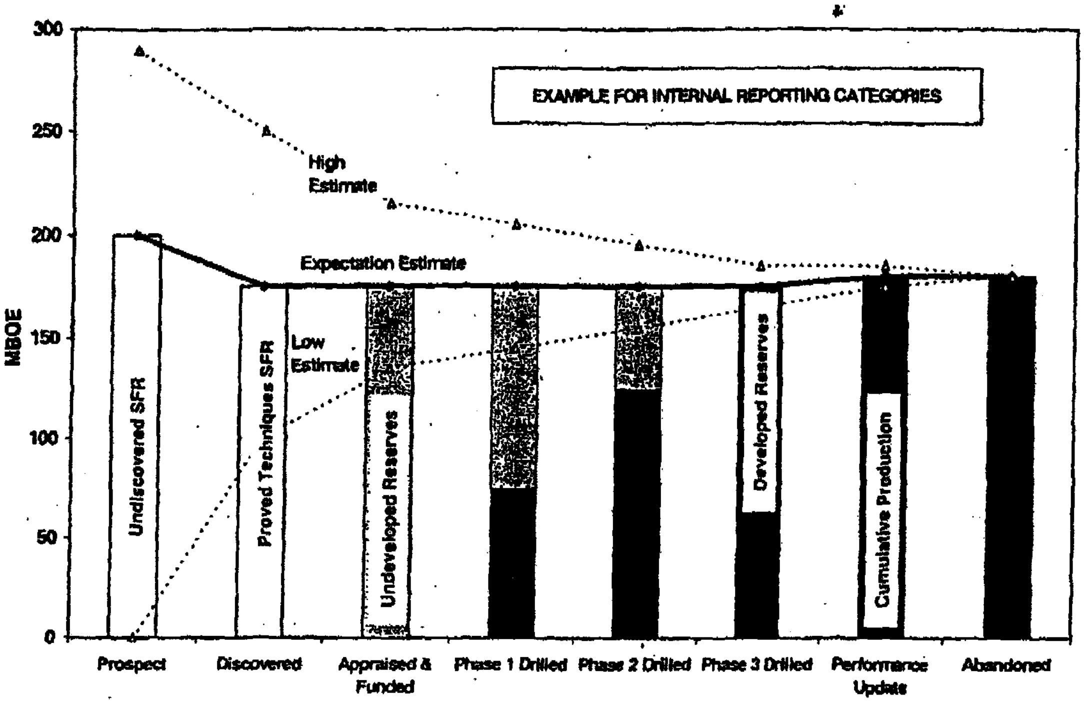
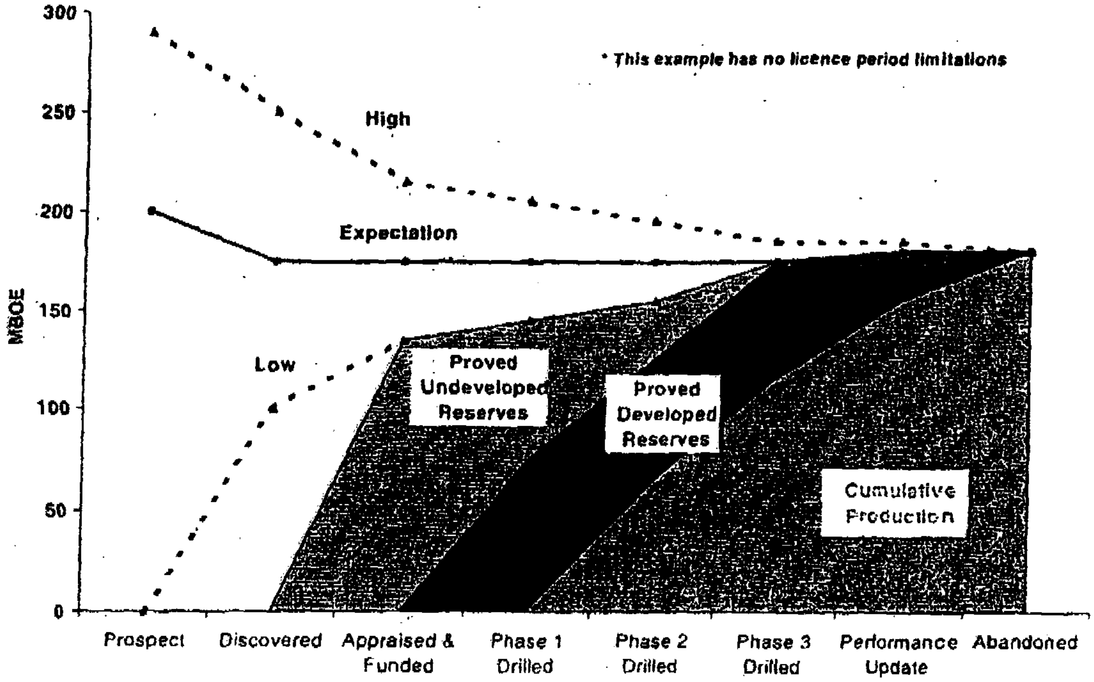
APPENDIX 2 RESOURCE MIGRATION DURING FIELD LIFE



EXAMPLE FOR EXTERNAL REPORTING CATEGORIES *



APPENDIX 3 SEC PROVED RESERVES DEFINITIONS

Transcribed from the Handbook of SEC Accounting and Disclosure 1998, pages F3-63 to F3-64 (Ref. 8). For a recent clarification by SEC, see Ref. 9.

Proved Reserves

Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

A. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test supports. The area of a 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 controls the lower proved limit of the reservoir.

B. Reserves 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.

C. Estimates of proved reserves do not include the following:

1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal (excluding certain coal-bed methane gas), gilsonite and other such sources.

Proved Developed Reserves

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for re-completion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery techniques is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

APPENDIX 4 SHELL INTERPRETATION OF SEC RESERVES DEFINITIONS

SEC Definition	Shell Interpretation for External Reporting (section 3.2)
Reasonable certainty; Proved Area includes portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled (if supported by geological and engineering data). In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Extended by production evidence, if conclusive.	Proved area delineated by fluid levels as interpreted from pressures in the reservoir. Laterally confined to areas of good and continuous seismic amplitudes, not beyond potentially sealing barriers. Extended by production evidence if conclusive. Proved developed reserves in new developed fields derived from a 'reasonably certain' scenario (best estimate) of current wells' future production, based on the Expectation post-drill 'proved area' volumetrics. With increasing cumulative production, the Proved estimate should grow towards the Expectation estimate when the field is mature (maturity ratio, i.e. cumulative production divided by expectation ultimate recovery, of some 40% or more). Proved undeveloped reserves in new or recently developed fields derived from a 'reasonably certain' scenario (best estimate) of future wells' production, based on the Expectation initial post-drill 'proved area' volumetrics. With increasing cumulative production, proved reserves should grow towards Expectation reserves for fully mature fields (maturity ratio of some 80% or more). Some exceptions may justify lower Proved/Expectation ratios.
Fixed RT prices at level prevailing at date of estimate	Prices fixed by SIEP ca. 6 months prior to estimate date, but amended if there is a subsequent significant change.
Fixed RT costs at level prevailing at date of estimate.	Costs fixed by OUs and NVOs at date of estimate. Flat MOD costs must be supported by technology plans to show that implied cost reductions are viable.
Economic producibility	Technically and commercially mature (i.e. positive discounted real terms cash flow for sufficient range of scenarios).
Producibility supported by either actual production or conclusive formation test supports	Producibility should normally be demonstrated by a conclusive test, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.
Improved recovery processes included only after successful testing by a pilot project or the operation of an installed program	Reserves from improved recovery processes are normally included following an in-situ test; by analogy with the same process being used elsewhere under similar conditions, or occasionally as a result of lab tests or simulation studies. Reserves associated with a firmly planned pilot can be booked.
'A gas market must exist'	Include only gas contracted or reasonably expected to be sold.
Developed reserves are from existing wells (including minor cost re-completions), existing facilities and operating methods	Existing wells, installed facilities and existing operating methods. Outstanding project activities can be considered existing if outstanding costs are minor (<10% of project) and approved. Includes volumes behind pipe if future costs are minor (<10% of a new well).

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APPENDIX 5 SEC RESERVES AUDITS - TERMS OF REFERENCE

The purpose of the SEC Reserves Audit is to verify that appropriate processes are in place in the OU to ensure that the proved and proved developed reserves estimates for external (SEC) reporting are prepared in accordance with the latest Group prescribed guidelines (SIEP 2001-1100/1101) and the FASB Statement of Financial Accounting Standards no.69 (SFAS-69).

The Audit will be carried out by the Group Reserves Auditor. His specific tasks during the audit shall be:

1) To verify the technical maturity of the reported proved and proved developed reserves estimates by assessing the quality of the engineering data and study work supporting the estimates and by verifying that undeveloped reserves are based on identifiable projects that can be considered technically mature.
2) To verify the commercial maturity of the reported reserves volumes by assessing the robustness of project economics and by establishing that these volumes can reasonably be expected to be sold in present or future markets.
3) To verify the 'reasonable certainty' of the reserves estimates by assessing the validity of uncertainty ranges used for their constituent parameters, by verifying that estimates are realistic in comparison with expectation estimates, by verifying that appropriate methods are used for mature fields and by establishing that appropriate methods of reserves addition (probabilistic / arithmetic) have been applied.
4) To verify that the Group share of proved and proved developed volumes has been calculated properly and that these volumes are producible within prevailing licence periods.
5) To verify that reported volumes are up-to-date and consistent with previous estimates, that changes are reported in the appropriate categories and that appropriate audit trails are in place for the study work supporting the reported reserves estimates.
6) To verify that reported reserves are net sales volumes and that the reported annual production (sales) volumes are consistent with those reported in submissions to Group Finance.

In case of deviations from the Group and FASB guidelines, the auditor shall establish whether and to what extent resulting estimates are likely to differ significantly from those that might be expected from the application of the standard guidelines.

The audit will be carried out by reviewing the reserves estimation and submission process through interviews of OU staff and by taking at random a number of fields for detailed analysis.

The frequency of the audit will in principle be once every four years for each OU, with possibility to extend this period to five years for medium and small OUs. Major reserves changes or concerns expressed during a previous audit may require an advancement of the next audit. For an OU reporting reserves for the first time, the first audit will in principle be within two years of this first submission.

The audit will in principle be carried out on OU premises and will be based on documentation available in the OU. Assistance of OU staff may be called upon.

An audit report will be submitted to the Managing Director of the OU, to the EP CEO and EP RBA, to the OU's Hydrocarbon Resource Manager and to KPMG the external auditors. It will be prepared and discussed in draft form on site, after which a final report will be prepared in The Hague, once formal OU comments are received. The report will contain an overall judgement (Good, Satisfactory, or Unsatisfactory), with itemised conclusions and recommendations.

APPENDIX 6 TERMINOLOGY

A6.1 Petroleum Resources Terminology

Reservoir

A reservoir is a discovered petroleum resource where internal pressure communication is known to exist between all identified geological sub-units.

In case of doubt, reservoirs are restricted to fault blocks / sedimentary units until production performance proves communication to exist across faults/ barriers. PVT properties can vary within a reservoir.

Field

A field is the collection of all petroleum resources within a closed areal boundary that belong to the same confining geological structure, and where the presence of petroleum has been demonstrated in at least one reservoir by a successful exploration well.

Field boundaries must be defined upon discovery and should encompass the unpenetrated petroleum resources in adjacent fault blocks and stratigraphic traps, if they are considered to be part of the same overall confining structure. Field boundaries may be re-defined on the basis of new geological information.

Potential Accumulations

Potential petroleum resources beyond existing field boundaries, where the presence of petroleum has not yet been demonstrated, are collectively called potential accumulations.

Producibility

Should normally be supported by a conclusive test in a drilled or immediately adjoining reservoir, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.

Production Facilities

The production facilities consist of all hardware installed to recover petroleum from the sub-surface resources and to deliver a quality controlled end-product for sale. These comprise the production and injection wells and the surface facilities for treatment, conversion, compression/ pumping, transport and delivery.

Surface Facilities

That part of the production facilities accessible at surface, connecting the wellheads ultimately to the delivery points.

Existing Development

The collection of all completed projects or sub-projects is referred to as the existing development.

Field quantities

Field quantities (also called 'Wellhead' quantities) are those quantities routinely measured at surface for individual well strings and expressed in terms of the stabilised products oil, condensate and (wet) gas or in terms of the type of injected fluids. These quantities may subsequently be reconciled with fiscalised sales and other product outlets, see below.

Sales quantities

The quantities sold after fiscal metering and delivered at the locations where the upstream company ceases to have an interest in the end-products. These can be expressed in terms of the general end-products oil, (dry) gas and natural gas liquids (NGL) or in terms of the actual product.

Field products and the subsequent sales products may be different and will be affected by own use and losses. The properties and volumes of end-products may be influenced by mixing and the petroleum type itself may be altered during surface processing. Since surface processing conditions may change during a project life, sales products may vary in specification and in relation to field products. To avoid ambiguity and double counting, a clear distinction must be made between recoveries in the field and the quantities estimated to be available for sale.

For general sales products, oil, gas and NGL, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such can be reported under oil. Separator condensate from gas wells and light hydrocarbon liquid products, derived from surface processing, if collected in a separate stream and sold as such are reported under NGL. Bitumen may be reported under oil in summary reports (with an appropriate footnote). In line with SEC requirements, sales volumes for gas should be those committed or committable to a gas contract. Committed Gas is covered by a gas contract. Committable gas reasonably expected to be assigned to a contract in the future.

It is necessary to maintain a more detailed internal administration of the actually sold products by stream in two cases: (1) If the upstream E&P company has separate contracts for delivery of special converted sales products such as LNG, methanol, ethane, LPG, C5+ etc., or (2) If there are special sales products like helium, sulphur or generated electricity.

Reconciliation

A monthly reconciliation is made between the fiscalised sales quantities and the quantities produced in the field. This is reported in the Monthly Report of Producing Wells (MRPW). The reconciliation process corrects for own use, flaring, losses and product conversion, and provides the end-product yield.

For reserves estimating purposes an average future yield factor is to be estimated (e.g. LPG/ wet gas yield, dry gas/ wet gas yield).

Ultimate Recovery

The ultimate recovery (UR) of a hydrocarbon field is the sum of cumulative production and the estimated volume of reserves (developed + undeveloped).

Total Resource Volume

The Total Resource Volume of a hydrocarbon field is the sum of cumulative production, the estimated volume of reserves (developed + undeveloped) and the Total Scope for Recovery.

A6.2 Probabilistic Terminology

Probability Density Function

The probability density function (PDF) of a stochastic variable indicates the probability that the actual variable value lies within a narrow interval around a particular value of the possible range, divided by the width of that interval.

Cumulative Probability Function

The cumulative probability function (CPF) of a stochastic variable describes the probability that the variable may exceed a certain value. The CPF is the mathematical integral of PDF.

P85

The value that has a 85% probability that it will be exceeded by the stochastic variable.

P15

The value that has a 15% probability that it will be exceeded by the stochastic variable.

Mean

The statistical mean of a stochastic variable is the probability weighted average of the variable over the entire variable range.

Mean Success Volume (MSV)

The probability weighted average of all realisations that equal or exceed the minimum reserves required for a commercial development of the resource.

Probability of Success (POS)

The probability that the minimum commercial volume will be exceeded and which therefore indicates the likelihood of any future development. The product of MSV and POS is the recovery expectation.

A6.3 Commercial Terminology

Discount Rate

A rate at which future real terms costs or cash-flow are discounted over time to calculate their present value.

Net Present Value (NPV)

The net present value of a project is the sum of the discounted annual cash flow, expressed in real terms money, over the period from the first project expenditure to abandonment. The net present value is expressed in million US$ at the relevant discount rate.

Expected Monetary Value (EMV)

The expected monetary value is a probabilistic balance of investments and revenues, expected from a set of conditional operational activities, comprising data acquisition and one or more development projects, which are arranged in an ordered sequence with probabilities assigned to each action (decision tree).

The EMV is the summation of the NPVs of projects, reduced by the costs of data acquisition activities, all expressed in discounted real term money and multiplied by their assigned probabilities. EMV is expressed in million US$ at the relevant discount rate.

Projects with a negative NPV for certain resource model realisations should be excluded from the EMV calculation, if the assumption is valid that data gathering will prevent such projects being implemented.

Unit Technical Cost (UTC)

The unit technical cost of a development project is defined as the sum of capital plus operating costs, expressed in real terms money, divided by the total production over the period from start-up to abandonment. In addition, both the cost and the production must be discounted. The reference date for the discounting should be the same for denominator and numerator (e.g. the first year of expenditure) and should be stated. The unit technical costs is expressed in US$/bbl (oil equivalent) at the relevant discount rate.

FID

Final investment decision, the decision (at CMD or senior executive level) to proceed with a project.

NFA forecast

No further (Capex) activity forecast, i.e. a forecast based on existing wells and facilities only.

A6.4 Exploration versus Development Wells

The classification of a well as either an exploration well or as a development well is determined (in line with SEC rules) based on the proved area as follows:

Proved Area

The proved area is the part of a property to which proved reserves have been specifically attributed (see also Section 3.1.3). It is delineated by the fluid levels seen / interpreted from drilled wells and by the area around those wells which geological / engineering data indicate to be producible.

Exploration Well

An exploration well is a well that is not a development well, a service well, or a stratigraphic test well.

Development Well

A development well is a well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

Service Well

A service well is either an injection well, a disposal well or a water supply well.

Appraisal Well

An appraisal well, or stratigraphic test well is a well drilled for geological information (not to test a prospect), either 'development-type' drilled in a proved area or 'exploratory-type' if not drilled in a proved area.