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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. To aid in understanding, planning, and decision making about these petroleum resources, resource volumes are classified according to the maturity or status of its associated development project. The current status and changes in petroleum resources, and specifically the commercially recoverable portion (reserves), are a significant concern to management. The future of the company depends on our effectiveness in maturing resources to the point where maximum economic value is realised.

For the Shell Group as a whole, petroleum resources are reported annually to senior management and are essential information for the strategic planning process of the upstream sector. The current status and changes to the proved and proved developed reserves are also reported annually to the Securities and Exchange Commission (SEC).

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). In 1998, the guidelines have been re-written, building on the foundation established by previous versions (References 1 to 5). These guidelines serve as a reference for OUs and NVOs and as the standard against which audits will be conducted.

The recommendations of the Hydrocarbon Resource Volume Value Creation Team have been incorporated in this update of the guidelines. The primary changes are increased attention to realise maximum value from volumes and the modification of the definition for proved developed reserves to be more consistent with industry practice. The value realisation theme is reflected in emphasising a) that reserves are project based and b) the importance of maturing resource volumes to developed reserves and hence sales. No major changes in the classification scheme are introduced.

This document contains only guidelines. The information on internal and external submission requirements and quantification methods that was contained in previous versions of this document will be included in other communications. Submission requirements will be communicated annually in a letter from EP Planning. Methods will be developed through the Hydrocarbon Resource Volume Common Interest Network (Reference 7).

The present, 1999 version contains a small number of corrections/modifications and clarifications compared to the 1998 edition, which are indicated by a line in the margin.

2. PETROLEUM RESOURCES

2.1 Definition

A petroleum resource is any accumulation of hydrocarbons that is known or anticipated t exist in a sub-surface rock formation, located in the company's current exploration an production acreage. If the petroleum resource extends beyond the company's licence area th resource volumes must be divided according to the granted licence boundaries, to tak proper account of Group share.

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

Resource volumes are tied to the project that develops them and are generally reported b field. The term **reserves** is used for resource volumes associated with a project that technically and commercially mature. Resource volumes that do not meet these criteria ai called **scope for recovery** (SFR). **Proved reserves** are the portion of reserves that reasonably certain to be produced. These distinctions will be discussed in Sections 3 and 4.

2.2 Group Share

Only the Group share of resource volumes is reported. The Group share is determined b agreements with the resource holders. Resource volumes can be distinguished according t three different types of agreement, which are discussed below.

Equity

Equity resources are the Group share of resources in Concessions. Concession agreemen lay down the general terms and conditions of operation. These agreements with governmen define the applicable tax rules, the Group share of resources in Concessions and the duratic of the production licence.

Entitlement

Entitlement resources are the Group share of production in acreage governed by Production Sharing Contract (PSC). The Group share of production is the Group interest the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms.

Innovative Production Contracts

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

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

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

1. The OU participates in the production operations as either operator or in partnersh with the operator, and so bears a share of the costs and risks of the producti operations.
2. The OU derives future economic value that is directly related to the volume hydrocarbons produced. For example, a fee expressed as a fixed or indexed amount p barrel of production would constitute a derivation of value from the produc hydrocarbons, but an operating fee that is largely independent of production would n The actual source of revenues used to pay the OU is not crucial to this point. F example, if the remuneration is determined by a produced gas volume but paid from revenues, the economic value to the OU is in effect derived from the produced gas, a this volume should be reported.

3. The OU 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. 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.

If an OU has interests in several licence areas subject to different contract types (e.g. reward generating and PSC), a separate submission must be made with respect to the interest in the reward generating contract area.

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

Licence or Contract Extensions

For internal reporting purposes, Group share of the expectation estimate of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the relinquishment date, but not 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 full life cycle volumes, resource volumes limited to the current licence only are recorded for total expectation reserves, developed expectation reserves and total commercial scope for recovery.

For external reporting, Group share of reserves (proved, proved developed) is limited to 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). Then 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.

Long Term Supply Agreements

FASB regulations (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.

Royalty 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 (payabl 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 ha formally elected to receive, or customarily receives, payment in cash, Group share o production and reserves should be reported without deduction of equivalent royalty volumes.

Fees in kind Third Parties may in some cases pay Fees in Kind or Tariff in Kind (TIK) for the use o infrastructure (e.g. pipeline tariff, processing fee). Such volumes received by the compan do not constitute a Group share in resources and should not be included in reported volumes Condensate volumes recovered from a pipeline system related to transportation of Thir Party gas volumes and sold by the company are equivalent to fees in kind received. All fee 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 d 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, wit associated revenues (at an agreed or fair market value) equivalent to booking of the incurre operating cost.

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

Under/Over Lift Group share should also allow for any historic under or over lift by partners or government.

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/deregulate gas market all gas reserves, which have a near certainty of market take-up can be classifie as 'committed'.

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

Gas Re-injection Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservatio underground storage (incl. cushion gas), or other reasons, remain part of a company' resource base and should be accounted for as such. These gas volumes should be classifie and reported as reserves or SFR, conform any other gas resource based on projec assumptions for re-development (taking into account expected re-saturation losses).

Gas volumes re-injected in an Under Ground Storage (UGS) project on behalf of a Thir Party (including any gas volumes previously sold by the company to this party) do n constitute a Group share in resources and should not be included in reported volumes.

Oil Sands Reporting of petroleum volumes (heavy oil, bitumen, syncrude, gas etc) recovered fro "oil sands" (tar sand, oil shales, coals etc.) as part of hydrocarbon resources (reserves c SFR) is principally governed by the method of recovery of such volumes. Volumes produce through wells, generally from thermal methods are reported as part of the hydrocarbo resource base. Volumes recovered though mining and subsequently recovered from th mined product are not part of the hydrocarbon resource base and should be reporte separately (see also Appendix 3 C4).

3. RESOURCE VOLUME CLASSIFICATION FOR INTERNAL REPORTING

3.1 Classification Scheme

The internal 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	
Reserves:	Developed Reserves Undeveloped Reserves
Discovered Scope for Recovery:	Commercial Scope for Recovery by Proved Techniques Commercial Scope for Recovery by Unproved Techniques Non-Commercial Scope for Recovery
Undiscovered Scope for Recovery	Undiscovered Commercial Scope for Recovery
Discovered Initial In Place	

Figure 1: Resource Categories for Internal Reporting

A summary of the definitions for these categories is provided in Appendix 1. The cascade model (Figure 2) illustrates the migration of volumes between resource categories during the development life cycle.

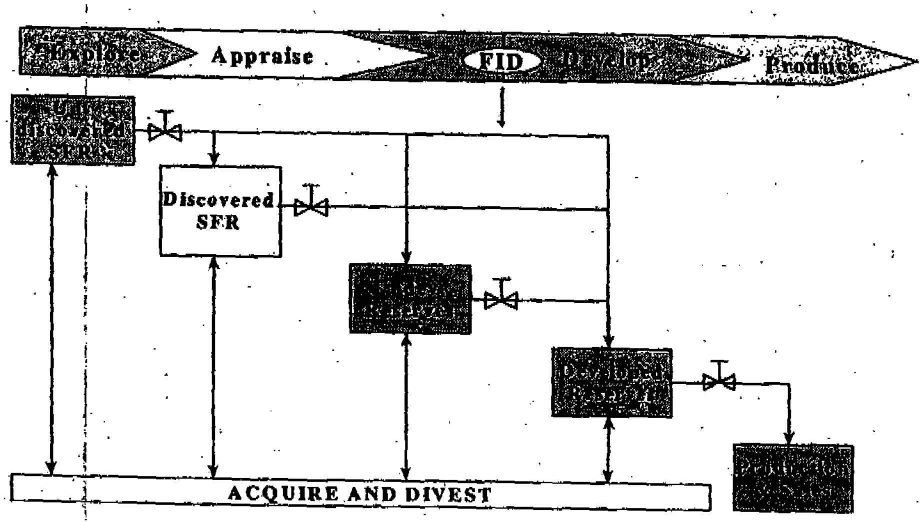


Figure 2: Cascade Model

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

3.2 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 interna classification scheme tied to the development life cycle is to enable understanding of th potential value and the actions needed to mature volumes. In order to achieve busines growth and reserves replacement objectives, it is essential that OUs and NVOs have efficien systems to move volumes through the value chain from scope for recovery to production an 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 valu realisation,

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

c) review ultimate recovery targets for existing fields and identify what activity - apprais study, new technology development, commercial agreement, etc. - is required to reac these targets,

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

3.3 Technical and Commercial Maturity

The classification scheme uses a project's technical and commercial maturity as the primar criteria to distinguish between reserves and scope for recovery (SFR). Resource volumes ca be classified as reserves only if the associated project that will result in production of thos volumes is considered to be technically and commercially mature. If it cannot, the resourc volumes should be classified as SFR. SFR needs an activity (e.g. exploration appraisal, fie trial, gas market development, etc) to achieve technical maturity and commercial viabilit Secondary technical and commercial distinctions (between proved and unproved techniqu SFR and between commercial and non-commercial SFR) further identify resource volum at various stages in the life cycle.

Project Basis

Technical and commercial maturity reflects the status of remaining uncertainties in tl assessment of the optimal development project and its associated recovery. A project is a proposed or notional modification of the wells, the production facilities and/or tl production policy, aimed at changing the company's sales product forecast. It can also be modification of the company's share in a venture (purchase/ sales-in-place, unitisation, new terms). The generic term 'project' is also used to describe a group of (sometim alternative) projects, each with a certain chance of realisation, depending on the results further data gathering. In that case, the project NPV is replaced by the Expected Moneta Value (or EMV, see Appendix 6).

Technically Mature

For a project to be **technically mature**, information on the resource volume, including level of uncertainty, is such that an optimal project can be defined with an auditable proje development plan, based on a resource and development scenario description, w drilling/engineering cost estimates, a production forecast and economics. The plan may notional or it may be an analogy of other projects based on similar resources. However, th should be a reasonable expectation that a firm development plan can be matured with tin Projects do not have to have a completed development plan.

Commercially Mature

A **commercially mature** project is commercially viable over a sufficiently large portion the range of possible scenarios that reflect the remaining resource uncertainties as well as t remaining commercial uncertainties, including market availability. The definition of wl constitutes "a sufficiently large portion" may vary from case to case and could for examj require the project NPV for the low reserves scenario to be positive for appropri commercial criteria. It is also likely to include an assessment of the capital exposure in c of project failure due to adverse resource realisations. The selected range of scenarios sho be documented and auditable.

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 (Reference 9).

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. However, economic viability or formal project approval is not required for a project to be considered commercially mature. Reserves may be booked before project approval is sought.

3.4 Uncertainty Estimates

Uncertainty in resource volumes arises from using data and prediction techniques with varying degrees of uncertainty. The uncertainty in resource volume estimates can be assessed and represented using a variety of methods (see Reference 7). Probabilistic methods determine a range of estimates and the associated probability that they will occur. Scenario deterministic methods determine best estimates for specific cases such as a low side case or a base case.

The terms low, expectation or high estimates are used in this document to simplify the discussion and to define reported volumes where consistency is required. When using a probabilistic methodology, low, expectation and high estimates are defined as the P85, Mean and P15 values from the probability distribution function (see Appendix 7 for definitions). When using a scenario deterministic methodology, low, expectation and high estimates are the low side case, base case and high side cases, respectively.

Only the expectation estimate for each of the resource categories is required for Internal reporting. The low estimate is usually used to define externally reported proved reserves. It is up to the OU to decide whether there is a need to determine other estimates.

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.

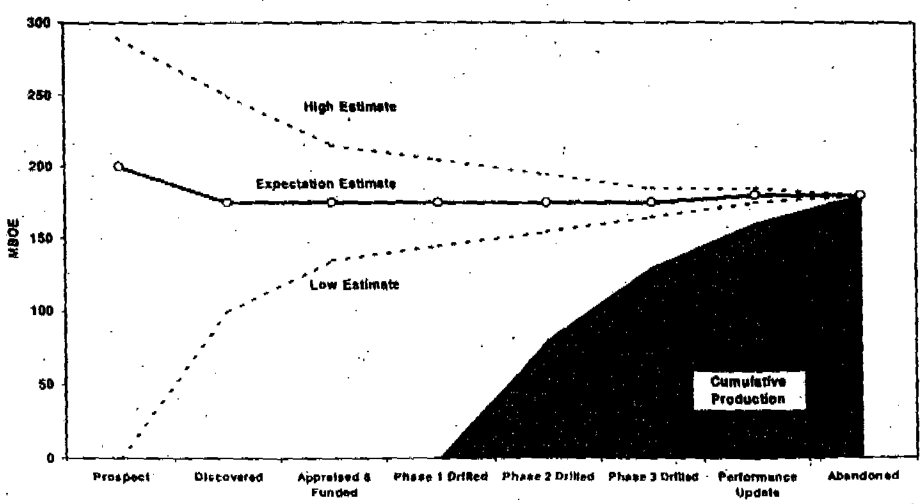


Figure 3: Uncertainty Reduction during the Field Life Cycle

Figure 3 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 lif cycle. This example is also used in Appendix 2 to show the migration of resources betwee internal and external reporting categories during the field life cycle.

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

Addition of Resource Volumes

Resource volumes are added together at various levels during the resource assessment an reporting process. Addition of reserves at or above the level used for depreciatio calculations must be arithmetical for consistency with financial accounting. Below this level i.e. normally below the field level, addition should be done taking into account th dependency between the volumes to truly reflect the recoverable volumes associated with project. Arithmetical addition is appropriate for dependent volumes, but usually overstate the uncertainty range for the sum of partially independent volumes. Probabilistic additio should be used for partially independent volumes when the difference with arithmeti addition is significant.

Note Rankin depreciated separately ... Reserves only

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

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

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

P 5
NR 4
Oil 5
G 3

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

1) A fault block that is not yet tested and may be reasonably interpreted as an extension the delineated area of the field. The project itself is technically and commercial mature. The untested block would be developed through existing field facilities witho significant additional investment other than additional wells, which is recognised in t 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) a project due to geological uncertainty. However, the nature of the project remai essentially unchanged and additional wells could be accommodated within the flexibil of the field facilities design, then the whole range of recoverable volumes should considered in deriving reserves. A scenario tree can be developed to represent the ran of outcomes, both in recovered volumes and optimised number of wells, dependent geological uncertainty. The uncertainty is resolved, with time, through planned d gathering eventually determining the number of wells. Hence the volumes can regarded as technically mature. If one branch of the scenario tree is not economic, th the volumes associated with that arm do not contribute to reserves.

If probabilistic addition is used, ensure the methodology and parameters used documented in the audit trail.

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

3.5 Cumulative Production

The resource volume category "Cumulative Production" pertains to summation of sales quantities of production volumes up to the date of reporting. Consistency is required between sales and field quantities. Production Operations and Finance functions must reconcile their figures prior to any submission (annual oil/NGL production [0933] and gas sales [0323] as reported in CERES upstream sector must equal the volumes reported in the annual resource statement using the appropriate unit conversion factors).

3.6 Reserves

Reserves are the sales quantities anticipated to be produced and monetised from a discovered field associated with a project that is **technically and commercially mature** (see definition in Section 3.3). Petroleum volumes have been demonstrated to be producible through wells from the field. A market must reasonably be expected to be available.

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) exceeds sales revenues after royalties. If the remaining tail production is significant, it may be booked as Non-Commercial SFR (see below).

The production forecasts must be adjusted for any volumes flared/vented and 'own use' (fuel for production facilities, compressors etc) in the upstream operations prior to transfer of the volumes to the buyer (Third Party or 'Downstream').

The restriction of marketability is relevant to gas reserves and for the classification of those NGL products that are subject to go-ahead of a non-associated gas project. Apart from an assessment of the local market and identification of the type of export project (e.g. pipeline, LNG, methanol), this restriction implies earmarking the gas resources suitable to feed these outlets. The restriction applies to all confidence levels (low, expectation and high estimates) of reserves.

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 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.

Developed Reserves

Developed reserves are the portion of reserves that is producible through currently existing completions, with installed facilities for treatment, compression, transportation and delivery, using existing operating methods. Outstanding project activities, such as initial completions, recompletions, hook-up and modifications to existing facilities, can be considered as existing or installed if the outstanding capital investment is minor (<10%) compared to the total project cost and if budget approval has been obtained. Volumes behind pipe are considered developed if additional activities (e.g. 'lower' zone abandonment, perforating, stimulating) do not require a full well entry/re-completion and if the future investment (normally opex) is minor (<10%) compared to a new well.

Developed reserves are estimated by forecasting the production that will be contributed by the existing wells through the currently installed facilities assuming no future development activity. Future wells or facilities may be planned that add reserves and/or accelerate the reserves that would be produced by the existing investments. However, the portion of reserves expected to be accelerated by future investments are classified as developed with the existing investments and not after the future 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 are classified as developed only after these investments are made.

Undeveloped Reserves

Undeveloped reserves are the complement of developed reserves in the total reserves requiring capital investment in new wells and/or production facilities in order to be produced.

For new development projects, developing additional 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 can only be classified as reserves if the project meets the technica and commercial criteria.

3.7 Scope for Recovery

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

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

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

Commercial SFR

SFR which is expected to be commercially viable should be reported in one of the followin three Commercial SFR categories.

Commercial SFR by Proved Techniques

SFR by proved techniques is the volume estimated to be recoverable from discovere resources, by a project utilising a recovery process or technique which has bee demonstrated to be technically feasible in the area or in the field. Implementation is expecte to be commercially viable, but a large range of technical uncertainty precludes th formulation of a technically sound project proposal.

Commercial SFR by Unproved Techniques

SFR by unproved techniques is the volume believed to be recoverable from discovere resources by a project utilising any recovery technique or process that has not yet bee demonstrated to be technically feasible in the field where its application is considered, bu which through laboratory or trials elsewhere has a reasonable chance of being technical feasible in the future. If feasible, the process should be expected to be commercial.

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

Undiscovered Commercial SFR

Undiscovered SFR is the volume believed to be recoverable from as yet undrilled potenti accumulations by any process that has been a technical success elsewhere, under simil conditions, and the development of which is expected to be commercial.

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

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

Non-Commercial SFR

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

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

The volumes reported for the four SFR resource categories numbers are based on full life cycle. In addition, total Commercial SFR within licence should also be reported.

3.8 Initial In Place

The petroleum volume Initially In Place (IIP) are 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.

4. RESOURCE VOLUME CLASSIFICATION FOR EXTERNAL REPORTING

4.1 Classification Scheme

Externally reported resource volumes have two primary purposes – financial calculation and investor assessments. The reported figures are used to calculate the depreciation of EI sector capital investments. The amount of depreciation affects the company's book earning that are also externally reported. Shareholders and the investment community use th reported volumes and earnings to assess the performance and value of the company. It i essential that externally reported proved reserves volumes are a true reflection of shareholde value. Externally reported proved reserves volumes should be equal to internally use proved reserves numbers.

The resource categories for external reporting are shown in Figure 4. Cumulative productio total proved reserves and proved developed reserves are externally reported annually for oi gas and NGL sales quantities as of the 1st of January. The reported volumes must compl with SEC definitions, reproduced in Appendix 3. The Shell Group definitions contained i this section are in full compliance with these definitions. Where Group guidelines interpr SEC definitions, as listed in Appendix 4, these interpretations have been accepted b external auditors as fulfilling SEC requirements. A summary of the Group definitions for th external categories is provided in Appendix 1.

Cumulative Production	
Proved Reserves:	Proved Developed Reserves Proved Undeveloped Reserves

Figure 4: Resource Categories for External Reporting

Cumulative production for external reporting has the same definition as used in the She internal classification scheme (see Section 3.5). An example of the migration of resour volumes between externally reported categories during a field's life cycle is shown Appendix 2.

4.2 Proved Reserves

Proved reserves are the portion of reserves, as defined for internal reporting, that **reasonably certain** to be produced and sold during the remaining period of existi production licences and agreements. Extension periods are only included if there is a leg right to extend, which may derive either from the initial concession agreement or from subsequent letter of assurance. Any applicable government restrictions on oil export a contractual or practical market limitations to gas delivery rates should be taken into accou Only the Group share of proved reserves is reported.

If probabilistic methods are used, reserves are reasonably certain when there is an 85 probability that the quantities actually recovered will equal or exceed the estimate. This the P85 value of the cumulative probability curve. If scenario deterministic methods used, the term reasonable certainty is intended to express a high degree of confidence tl the quantities will be recovered. This is the low side estimate. When the estimate assun significant volumes of hydrocarbons outside the defined fluid contacts, or when the recove mechanism is untested in the field or analogue fields, a lower estimate should be used tl reflects this uncertainty.

As discussed in Section 3.4, proved reserve estimates should be updated annually based development and performance data.

Proved Developed Reserves

Proved developed reserves are the reasonably certain portion of internally reported developed reserves (i.e. produced from existing wells through installed facilities). Drilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations, as discussed above. The expectation estimate is the mean value if probabilistic methods are used or the base case estimate if scenario deterministic methods are used and should tie-in with the expected No Further Activity (NFA) production forecast.

Proved Undeveloped Reserves

Proved undeveloped reserves are the reasonably certain portion of internally reported undeveloped reserves (i.e. require additional capital investment for new wells or facilities). Reasonable certainty is met by using the P85 value or low side estimate of undeveloped reserves and taking into account undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations, as discussed above.

Total proved reserves and proved developed reserves are often determined, and then proved undeveloped reserves is the difference between the two. In mature fields when most of the reserves have been developed, this approach can result in values for total proved reserves and proved undeveloped reserves that are no longer reasonable. Once a field is at this level of maturity, a deterministic approach should be used for both proved developed reserves and proved undeveloped reserves consistent with the SEC and SPE definitions (Appendix 3, Reference 8). Total proved reserves is then the sum of proved developed reserves and proved undeveloped reserves.

Estimates of proved reserves should be benchmarked against the "proved area" deterministic method consistent with the SEC and SPE definitions (Appendix 3, Reference 8). This method first defines the proved area[2] of the field and then estimates the volumes expected to be recovered from the proved area. If the proved and proved developed reserve estimates are significantly different using the proved area method (as generally used in the industry), a reconciliation should be made for 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 since third parties, e.g. gas buyers and hence external reserves auditors for certification, may adopt different practices.

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.

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.

[2] The area of the reservoir considered as proved area includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data (Reference 8).

3) Project financing has been obtained or is expected to be available without a pilot testing phase.

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

Proved Gas Reserves in External Disclosures

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, while 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.

Proved Reserves under Constrained Production

When operating under a combined production constraint (e.g. oil production quota) and production beyond the licence or agreement period is expected, the capability to accelerate the post licence production provides a safeguard against under-performance of the planned development programme during the licence period. This capability increases the confidence level that can be assigned to the constrained production forecast during the licence period. In this circumstance, the proved reserves should be based on an accelerated development programme that could be followed in the event that the base plan delivered less production than expected.

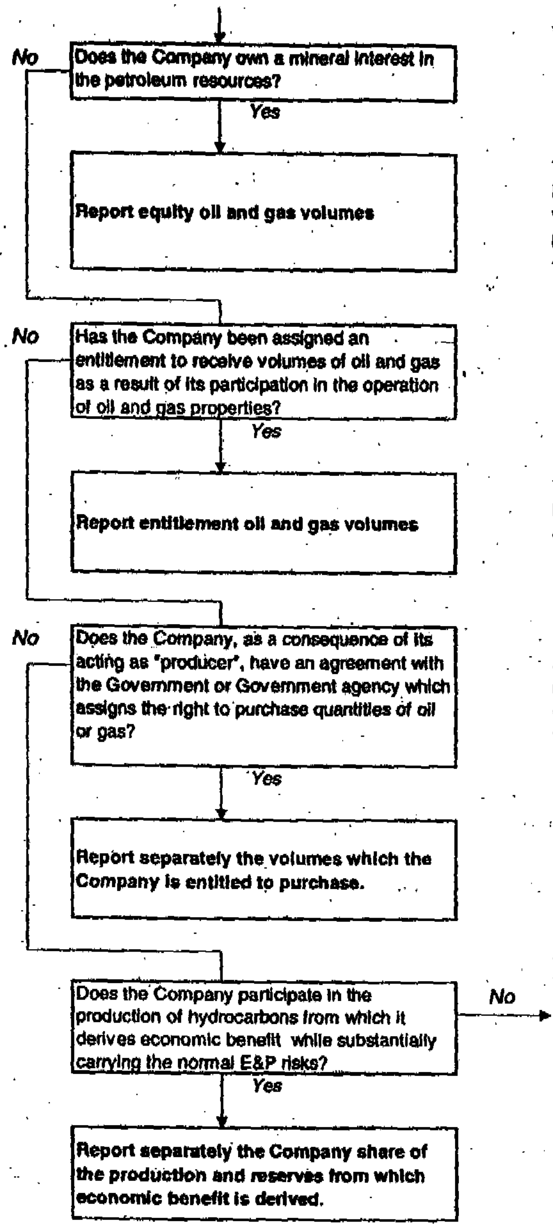
Types of Agreements

Under US Financial Accounting Standards Board (FASB) regulations, separate disclosure is required for oil and gas volumes applicable to different types of agreements. These requirements are illustrated in Figure 5.

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.[3]

[3] Inclusion of minority interest requires prior agreement with the Group.



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 5: Types of External Disclosures in Relation to FASB Regulations

5. RESOURCE VOLUME REPORTING, RESPONSIBILITIES AND AUDITS

5.1 Shareholder Requirements

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

Volumes will be reported based on the classification systems described in Sections 3 and 4 Additional information is reported for the calculation of the Standardized Measure require by the US Financial Accounting Standards Board (FASB).

5.2 Methods and Systems

OUs and NVOs are responsible for selecting the methods and systems that are technicall most appropriate for quantifying the resource volumes of their assets consistent with thes guidelines. The preferred methods and systems may vary depending on the type of resourc and with time as the resource matures and technology improves. Best practices will b developed, updated and shared in the Hydrocarbon Resource Volumes Managemer Common Interest Network (Reference 7). This network will replace the material previousl covered in Volume 2 of the 1988 guidelines (Reference 1).

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

The Group Reserves Auditor will review decisions on methods and systems during tł periodic audits. As far as these methods bear on the estimation of externally reporte resource volumes, the Group Reserves Auditor will ensure that recommended methods a acceptable to the external auditors.

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

5.3 Responsibilities and Audit Requirements

EP Planning Responsibilities

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

Reserves Auditor Responsibilities

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

Operating Unit Responsibilities

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

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

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

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 SEPI (responsible RBA).

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 SEPIV/SEPI, 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.

Audit Trail

For all the reported resource volumes an audit trail must be available of the assumptions made and process 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, SEPIV/SEPI should be advised at the earliest opportunity.

REFERENCES

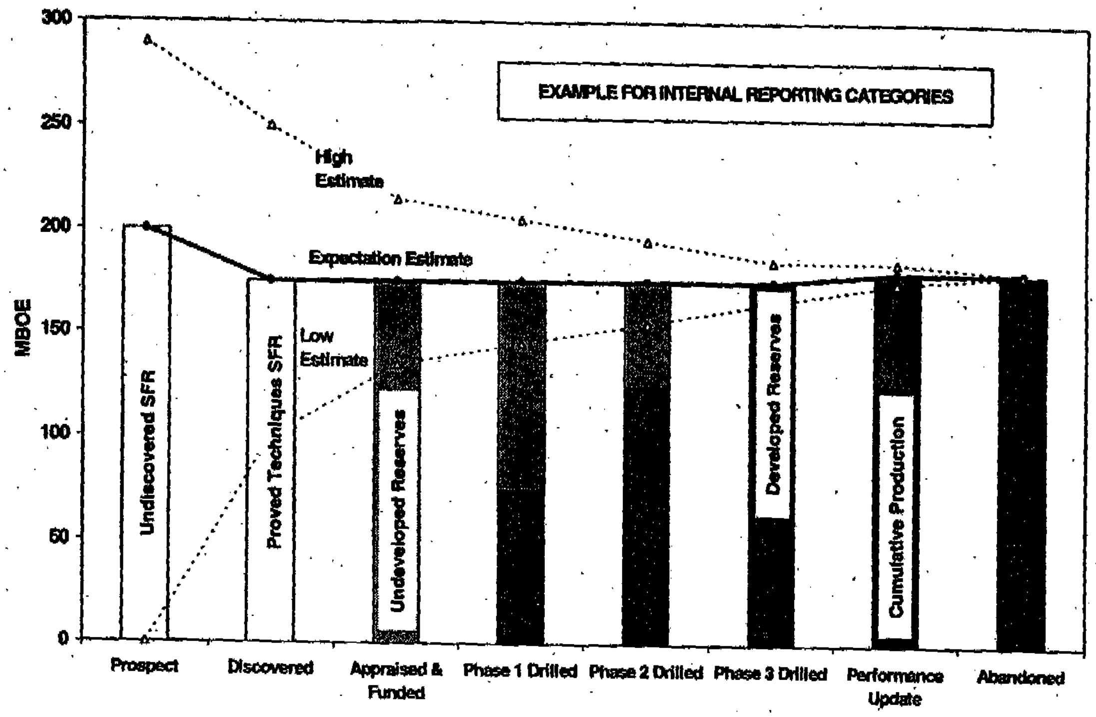
1. EP 88-1140 Part 1, Classification, definitions and reporting requirements,
1a. EP 88-1145 Part 2, Methods and procedures for resource volume estimation, SIPM, April 1988
2. EP93-0075 Petroleum Resource Volume Guidelines, May 1993
3. Revision of Report EP93-0075, 12 August 1994
4. Revision of Report EP93-0075, 10 November 1995
5. Revision of Report SIEP97-1100, September 1997
5a. Revision of Report SIEP98-1100 & 1101, September 1998
6. EP92-0945 Business Process Management Guideline, SIPM, EPO/72, June 1992
7. Hydrocarbon Resource Volume Common Interest Network, http://sww1.epglobal.shell.com/value/index.htm
8. Petroleum Reserves Definitions, Society of Petroleum Engineers and World Petroleum Congresses, http://www.spe.org/technology2/reserves.html
9. Project Evaluation and Screening Criteria, SIEP 99-2030, June 1999
10. Handbook of SEC Accounting and Disclosure
11. Financial Accounting Standards Board (FASB), e.g. Statements 19, 25 and 69.

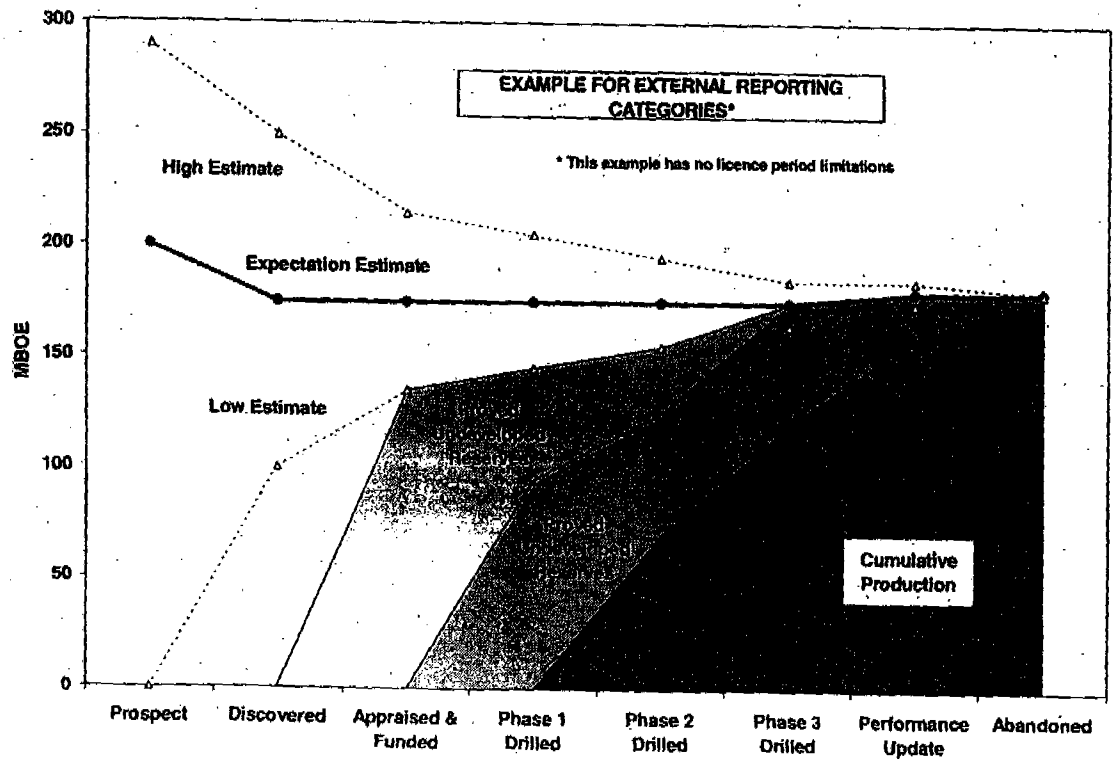
INDEX

APPENDIX 1: RESOURCE CATEGORY (QUICK REFERENCE)

External Reporting	Internal Reporting	Proved Reserves		• Portion of reserves, as defined for internal reporting, that are reasonably certain • 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 Developed Reserves	• Proved reserves producible through existing completions and installed facilities using existing operation methods • Outstanding project activities considered completed if remaining cost <10% of total
			Proved Undeveloped Reserves	• Proved reserves which require capital investment (wells and/or facilities)
	Internal Reporting	Reserves		• Project is "technically and commercially mature" Note: Formal project approval or economic viability is not required • Market is reasonably expected to be available • Includes only production with positive cash flow • Not restricted by licence period • Group share reported
			Developed Reserves	• Reserves producible through existing completions anc installed facilities using existing operation methods • Outstanding project activities considered completed ii remaining cost <10% of total
			Undeveloped Reserves	• Reserves which require capital investment (wells and/o facilities)
		Scope for Recovery		• Project is <u>not</u> technically and/or commercially mature • Not restricted by licence period • Group share reported
			Commercial SFR by Proved Techniques	• Discovered • Commercially viable • Techniques have been proved to be feasible in thi resource • A sound technical project proposal is not possible ye due to large range of technical uncertainty • Market not currently available
			Commercial SFR by Unproved Techniques	• Discovered • Commercially viable • Recoverable by techniques that have been successfu elsewhere, but cannot yet be demonstrated to be feasibl in this field • Laboratory work or trials elsewhere have a reasonabl chance of demonstrating feasibility in this field • Discounted for the risk that the considered techniqu will not prove to be feasible
			Non-Commercial SFR	• Discovered • Not commercially viable even if technically successful • Commercially viable with a change of commerci circumstances • Unit Technical cost below an annually advised ceiling • Remaining tail production if it is significant
			Undiscovered Commercial SFR	• Recovery from undrilled prospects • Commercially viable exploration and development • Techniques have been successful elsewhere und similar conditions • Discounted for the risk that commercial volumes are n present

APPENDIX 2: RESOURCE MIGRATION DURING FIELD LIFE





APPENDIX 3: SEC PROVED RESERVES DEFINITIONS

(Transcribed from the Handbook of SEC Accounting and Disclosure 1998, pages F3-63 t· F3-64)

Proved Reserves

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

A. Reservoirs are considered proved if economic productibility is supported by either actu. production or conclusive formation test supports. The area of a reservoir considere proved includes:

1. that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, any, and
2. the immediately adjoining portions not yet drilled, but which can be reasonably judge as economically productive on the basis of available geological and engineering data. the absence of information on fluid contacts, the lowest known structural occurrence hydrocarbons controls the lower proved limit of the reservoir.

B. Reserves which can be produced economically through application of improv recovery techniques (such as fluid injection) are included in the "proved" classificatio when successful testing by a pilot project, or the operation of an installed program in tl reservoir, provides support for the engineering analysis on which the project or progra 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 "indicated additional reserves";
2. crude oil, natural gas, and natural gas liquids, the recovery of which is subject reasonable doubt because of uncertainty as to geology, reservoir characteristics, economic factors;
3. crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; an
4. crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, cc (excluding certain coalbed methane gas), gilsonite and other such sources.

Proved Developed Reserves

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

Proved Undeveloped Reserves

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

APPENDIX 4: SHELL INTERPRETATION OF SEC RESERVE DEFINITIONS

SEC Definition	Shell Interpretation for External Reporting
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...In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.	If probabilistic methods are used, reserves are reasonably certain when there is an 85% probability that the quantities actually recovered will equal or exceed the estimate. This is the P85 value of the cumulative probability curve. If scenario deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. This is the low side estimate. When the estimate assumes significant volumes of hydrocarbons outside the defined fluid contacts, or when the recovery mechanism is untested in the field or analogue fields, a lower estimate should be used that reflects this uncertainty. Drilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts and untested recovery mechanisms.
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 productibility	Technically and commercially mature (i.e. positive discounted real terms cash flow for sufficient range of scenarios).
Productibility supported by either actual production or conclusive formation test supports	Productibility 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.
No gas qualifier	Include only gas contracted or reasonably expected to be sold.
Developed reserves are from existing wells (including minor cost recompletions), existing facilities and operating methods	Existing wells, installed facilities and existing operating methods. Outstanding project activities can be considered existing or installed if outstanding costs are minor and approved. This includes volumes behind pipe if future costs are minor.

APPENDIX 5: SEC AUDIT - 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 99-1100/1101) 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 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

A) 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 NGLs, 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 are 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 commitable to a gas contract. Committed Gas is covered by a gas contract. Commitable 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+, 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 petroleum type is the sum of cumulative production and the estimated volume of reserves.

B) Probabilistic Terminology

Probability Distribution Function The probability distribution function 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.

P85 The value that has a 85% probability that it will be exceeded.

P15 The value that has a 15% probability that it will be exceeded.

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

C) 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 NPV's 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.

D) *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.

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 basically any well which 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.

Shell International Exploration and Production B.V.

Confidential
SIEP 99-1101

Petroleum Resource Volumes

Submission requirements for internal and external reporting

(for Operating Units & New Venture Operations)

Confidential
SIEP 99-1101

Petroleum Resource Volumes

Submission requirements for internal and external reporting

(for Operating Units & New Venture Operations)

Custodian	:	SEPIV-EPB-P
Date of issue	:	November 1999
Keywords	:	Resource Volumes, Guidelines, Reserves, FASB, SEC

SHELL INTERNATIONAL EXPLORATION AND PRODUCTION B.V., THE HAGUE

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Contents

List of Appendices

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Purpose

This document provides the guidelines for the annual submission of internal and external resource volumes statements. These guidelines should be used in conjunction with the 'Petroleum Resource Volume Guidelines: Resource Classification and Value Realisation' (Reference 1). External reporting requirements comply with SEC rules and FASB statements (References 2 and 3).

The annual statement of Resource Volumes is submitted in the beginning of each year to EP Planning (SEPIV-EPB-P) by Operating Units (OUs), New Venture Organisations (NVOs) and Non Operated Ventures (NOVs).

EP Planning is responsible for aggregating the data at Group level and for the internal and external reporting. The Group Reserves Auditor will verify the data for external reporting.

Detailed information is provided in the appendices:

Appendix 1	Submission Requirements for Internal Reporting;
Appendix 2	Submission Requirements for External Reporting; and
Appendix 3	Guidance for the electronic spreadsheet 'Reserves Reporting Workbook'.

Schedule

The 1999 Resource Volume Statements should be with the Group Hydrocarbon Resource Coordinator in the Hague by the following dates:

Non-producing ventures	by **Wednesday 12 January 2000** (COB Local Time); and
Producing ventures	by **Wednesday 19 January 2000** (COB Local Time).

The data should be submitted in electronic format using the electronic (Excel) spreadsheet 'Reserves Reporting Workbook' as provided to each OU/NVO/NOV reserves focal point. The electronic workbook (password protected) can be submitted via Email or on diskette.

OU/NVO/NOVs should submit (by mail) signed copies of all internal and external resource reporting forms as approved at the appropriate level e.g. Technical Manager, General Manager or equivalent. The Standardized Measure submission should also be signed by the Finance Manager. Signed copies should be in the Hague offices no later than one week after the reporting deadlines given above.

Submissions by Email (password protected) should be addressed to Remco Aalbers SEPIV EPB-P (Remco.RD.Aalbers@sepivbv.shell.com).

Paper mail should be addressed to:

R.D. Aalbers (EPB-P)
Group Hydrocarbon Resource Coordinator
Shell EP International Ventures BV.
P.O. Box 663
2501 CR The Hague
The Netherlands

Tel. +31-70-377 2001
Fax. +31-70-377 2460

All submissions should be copied to the respective Regional Business Advisor (RBA).

Opening and Closing Statements

In view of the early reporting date, preliminary estimates of end year reserves and resources are accepted. Oil/NGL production and gas sales volumes should equal volumes reported as full year actual in CERES.

Opening reserves and resource statements should be equal to previous year's (preliminary) closing statements as submitted to the Group. The workbook received by each OU/NVO/NOV already includes their respective closing numbers from last year as a fixed input.

Units and Conversion Factors

Oil and NGL

Oil and NGL volumes are reported in m^3 sales volumes at standard conditions (15°C and 760 mm Hg).

1 bbl (15°C, 760 mm Hg) = 0.1590 m^3 (15°C, 760 mm Hg)

Gas

Gas volumes are reported in two different units:

1) Sales volumes "*tel quel*" (i.e. at its inherent heating value) in cubic meters at standard conditions (15°C and 760 mm Hg).

   Conversion factors between standard cubic meters (sm^3) and standard cubic feet (scf) are as follows:

   1 sm^3 (15°C, 760 mmHg) = 35.3147 scf (15°C, 760 mm Hg)
   = 35.2899 scf (60°F, 30 in Hg)

   1 scf (15°C, 760 mm Hg) = 0.02832 m^3 (15°C, 760 mm Hg)
   1 scf (60°F, 30 in Hg) = 0.02834 m^3 (15°C, 760 mm Hg)

2) Sales volumes at Normalised conditions (i.e. adjusted to an average heating value) in cubic meters at normal conditions (0°C, 760 mm Hg) and a gross heating value (GHV) of 9,500 kcal/nm3.

   Conversion between standard cubic meters (sm^3) and Normalised cubic meters (Nm^3) is carried out in two steps:

   a) Volume conversion reflecting the temperature change from standard cubic meter (sm^3) at 15°C to normal cubic meter (nm^3) at 0°C:

   1 sm^3 (15°C, 760 mm Hg) = 0.9480 nm^3 (0°C, 760 mm Hg)

   This conversion may - to some extent - depend on gas composition and slightly different values may apply.

   b) Volume conversion reflecting the gross heating value change from actual GHV ("tel quel") to a GHV of 9,500 kcal/Nm^3, for instance:

   1 nm^3 (GHV = 10,000 kcal/nm^3) = 10,000/9,500 = 1.0526 Nm^3 (GHV = 9,500 kcal/nm^3).

   Heating value conversion factors are:

   9,500 Kcal/nm^3 = 39.7480 MJ/nm^3
   1,000 btu/scf (15°C, 760 mm Hg) = 39.3027 MJ/nm^3
   1,000 btu/scf (60°F, 30 in Hg) = 39.2751 MJ/nm^3

e.g. for a gas with an average GHV of 1,000 btu/scf:

1 Nm^3 (9,500 kcal/nm^3) = 37.6738 scf (1,000 btu/scf)

See references 4 and 5 for other conversion factors if required.

Barrel of Oil Equivalent (boe)

Conversion of gas volumes to barrel of oil equivalent is (generally) defined as follows:

1 boe = 5.8 mln btu

As 'boe' is defined in terms of total energy, conversion of gas volumes to 'boe' depends on the average GHV of the gas as follows:

1 boe = 5,800 scf (GHV = 1,000 btu/scf)

1 boe = 153.95 Nm^3 (GHV = 9,500 kcal/nm^3)

e.g. for a gas with an average GHV of 1,100 btu/scf:

1 boe = 1,000/1,100 * 5,800 = 5,273 scf (GHV = 1,100 btu/scf)

References

1. Petroleum Resource Volume Guidelines: Resource Classification and Value Realisation; SIEP 99-1100, September 1999.
2. Financial Accounting Standards Board (FASB), e.g. Statements 19, 25 and 69.
3. Handbook of SEC Accounting and Disclosure, e.g. paragraph F3, Oil and Gas Entities.
4. Production Handbook, Volume 1; SIPM, 1991.
5. Natural Gas Terms and Measurements, SIG/69/1, SIG Ltd., 1992.

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A1 Internal Reporting

The following submissions are required for internal reporting:

1. **Expectation Estimate of Reserves Volumes Oil, NGL, and Gas**

   Group share of expectation estimate of reserves as at 31 December 1999 and reconciliation with the reserves reported in the previous year. A breakdown (by field) should be provided separately for significant changes in the expectation estimate of reserves. Expectation reserves are estimates of full life cycle future sales volumes.

2. **Expectation Estimate of Scope for Recovery Oil, NGL and Gas**

   Group share of expectation estimate of Scope for Recovery (SFR) as at 31 December 1999 and reconciliation with the SFR reported in the previous year. SFR volumes are reported as full life cycle numbers.

3. **Expectation Estimate of Exploration Discoveries Oil, NGL and Gas**

   Records the discoveries during the year 1999 with the expectation estimate of recoverable resources.

4. **Exploration Discoveries and Revisions Oil/ NGL and Gas**

   Provides a summary of exploration discoveries and revisions over the last ten years comparing initial estimates of discovered volumes (in the year of discovery) with current estimates of resources for the same fields.

   Combined with the exploration expenditure for each year provides an estimate of Unit Finding Costs.

5. **Summary of Resources by Field** (new request)

   Records a summary of resource volumes by field for each resource category. Input is split between oil and gas fields, with additional information on location (onshore, offshore or deepwater), on operated status (operated or non-operated), on oil and gas quality (API & GHV), group share in the field as well as area/contract information (free format per OU/NVO/NOv).

   Details should be provided for all the large and medium size fields within each venture, but small fields may be aggregated into one (or more) "other small fields" entries. Small fields (together less than 10% of the total reserves) should be grouped within the same 'subset' (e.g. offshore & operated, or onshore & non-operated). Equally exploration potential (Commercial SFR-undisc) may be aggregated from prospects/leads into concession block(s) etc as long as grouping is within an equivalent 'subset'.

A1.1 Licence and Contract period

For internal reporting purposes, Group share of the expectation estimate of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the licence period. The currently existing licence terms or other anticipated terms should be assumed for this extrapolation.

In the submission for Expectation Reserves (under 1 above), also the expectation estimate of both developed and total reserves that will be produced within the licence period is requested.

In the submission for Scope for Recovery (under 2 above), also total commercial SFR within Licence is recorded.

A1.2 Change Categories

Reserves	Scope for Recovery (SFR)
New Fields	New Entries
Extensions	Discoveries
Terms and conditions	Terms and conditions
Purchases in place	Purchases in place
Sales in place	Sales in place
Improved recovery (to/from SFR)	Transfers to/from reserves
Economic Revisions	Economic Revisions
Technical Revisions	Technical Revisions
	Deletions
Production	

The change categories that apply to internal reporting are defined as follows:

New Fields This category includes only Reserves volumes that are allocated for the first time to a discovered field. This could occur directly upon discovery by a successful exploration well but only if a technically mature and commercially viable development plan can already be formulated. This also includes first time allocation of reserves for discovered fields for which volumes were previously booked as SFR that are transferred to reserves following firming up of a technically mature and commercially viable development plan.

New Entries Pertain to SFR estimates entered for the first time for a new identified petroleum resource and/or project. Transfers from reserves are thus not included in this category.

Extensions Include only the Reserves allocated for the first time to a discovered accumulation (e.g. a new fault block or reservoir), located within the boundaries of a field that already carries Reserves.

Discoveries Include only SFR volumes that are allocated for the first time to a discovered field as a result of a successful exploration well. It is noted that, immediately upon discovery of the presence of hydrocarbons in a field, it may not yet be possible to prepare a technically mature and commercially viable development plan.

Terms & Conditions Describe Reserves/ SFR changes that are solely due to the allocation or retraction of a production or exploration licence/contracts, and/or to adjustments to the terms of existing licences/contracts, including licence/contract extensions.

Purchases in Place Include Reserves/ SFR additions solely due to equity changes as a result of a financial or barter transaction.

Sales in Place Include Reserves/ SFR reductions solely due to equity changes as a result of a financial or barter transaction.

Improved Recovery (to/from SFR) Describes positive reserves changes allocated to a field where Reserves were already carried and consists only of transfers from SFR of volumes associated with new projects, that were hitherto not deemed technically mature or commercially viable to contribute to reserves. This excludes Extensions, which should be reported separately. In the audit trail, the reasons for such transfers should be given, as well as an indication whether the project pertains to an improvement in the sub-surface recovery technique or in surface processing.

Negative reserves changes reflect the de-booking of volumes previously carried as reserves but no longer considered to be technically and commercially mature to SFR.

Transfers Include those positive (negative) SFR changes that involve a reclassification of Reserves into (from) SFR. Negative Transfer volumes in SFR should be accompanied by positive volumes in the appropriate Reserves change category, and vice versa.

Revisions General Include corrections to previous estimates of recovery for a project, or of previous IIP estimates for a resource, based on new information, re-evaluation and/or the conclusion of a unitisation agreement. Transfers of entire project resource volumes out of Reserves into SFR should be included in this category, with the reasons to be stated in the audit trail. Reserves revisions also include transfers from non-commercial SFR if the latter are due to changes in the economic abandonment rates for projects that already carry reserves.

Economic Revisions Include those revisions that are solely due to a change in the advised Group reference criteria for commerciality.

Technical Revisions Include all other revisions. If during a year, a project has been subject to technical revisions, whilst there has also been a change in reference criteria, the economic revisions should be calculated separately, where possible.

Production Sales quantities sold during the year after fiscal metering and delivered at the location where the upstream sector ceases to have an interest in the end products.

Deletions Pertain to SFR estimates for resources relinquished, projects withdrawn from the system and failed exploration/appraisal.

Please note that in the electronic workbook a number of logical links have been made to ensure consistent reporting of changes between SFR (transfer to/from reserves) and the equivalent changes to expectation reserves (new fields/discoveries, extensions and improved recovery). Data should be entered on the relevant SFR sheet and is automatically linked to the expectation sheet.

Similarly to ensure consistent reporting of production volumes these should be entered on the proved reserves sheet(s) for external reporting and are linked to the expectation sheet.

Further logical links are included between the volumes reported on the 'Discoveries 1999' sheet and volumes recorded as "discoveries" on the 'SFR' sheets and 10 year exploration overview sheets. The number of successful exploration wells reported in the statistics sheet are linked to the number of discoveries reported in the 'Discoveries 1999' sheet.

A1.3 Reconciliation of Changes

In principle, a reclassification should not alter the transferred quantity, nor the number of identified projects. Similarly, a revision should pertain to a change of the quantity estimated for a particular project, and should not affect the number of projects identified in the system. The latter can only be changed by new entries and deletions.

In practice, many resource volume changes will actually consist of a combination of constituent changes. For instance, a successful exploration well will cause a reclassification from undiscovered SFR to one of the discovered resource categories (Discovery or New Field), whilst at the same time it will provide new data that may modify the previously estimated resource volumes (Revision). Similarly, a development study may re-classify a resource from SFR to Reserves (Improved Recovery), whilst the new volumetrics will increase the Initially-in-Place estimate (Revision). Upon reclassification, the revision should be shown in the previous category and the new estimate will be transferred to the target category.

For reconciliation purposes, it is desirable for each composite change to be evaluated and stored as a number of constituent changes, each in its separate category.

Resource Volumes and Associated Change Categories

From \ To \	Cum Prod'n	Developed Reserves	Undev Reserves	Proved Tech SFR	Unprov. Tech SFR	Undisc'd SFR	Non-Comm SFR	Not carried
Cumulative Production	*TR*	-	-	-	-	-	-	-
Developed Reserves	Prod'n	TR/ER	-	-	-	-	ER/TC	SIP
Undeveloped Reserves	-	Develop't /TR	TR/ER	TR/ER	-	-	ER/TC	SIP
Proved Tech SFR	-	*IR/TS*	IR/TS	TR/ER	-	-	ER/TC	SIP /DEL
Unproved Tech SFR	-	*IR/TS*	IR/TS	TR	TR/ER	-	ER/TC	SIP /DEL
Undiscovered SFR	-	*NF/EX*	NF/EX	DIS	DIS	TR/ER	ER/TC	SIP /DEL
Non-comm SFR	-	ER/TC	ER/TC	ER/TC	ER/TC	*ER/TC*	TR/ER /TC	SIP /DEL
Not carried	-	PIP	PIP	PIP/NE	PIP/NE	PIP/NE	PIP/NE	-

DIS	Discovery	**IR**	Improved Recovery	**SIP**	Sale in Place
DEL	Deletion	**NE**	New Entry	**TC**	Term & Conditions
ER	Economic Revision	**NF**	New Field	**TR**	Technical Revisions
EX	Extension	**PIP**	Purchase in Place	**TS**	Transfer to/from SFR

Note; Italics indicate change categories which, although possible, are less common.

A1.4 Submission sheets

Internal reporting:	Expectation estimate of reserves volumes: Oil, NGL and Gas
Internal reporting:	Summary of Resources by Field
Internal reporting:	Expectation estimate of Scope for Recovery: Oil
Internal reporting:	Expectation estimate of Scope for Recovery: NGL
Internal reporting:	Expectation estimate of Scope for Recovery: Gas
Internal reporting:	Expectation estimate of Exploration Discoveries
Internal reporting:	Expectation estimate of Exploration Discoveries and Revisions 1990 - 1999: Oil/ NGL
Internal reporting:	Expectation estimate of Exploration Discoveries and Revisions 1990 - 1999: Gas

Internal reporting: Expectation Estimate of Reserves Volumes: Oil, NGL, Gas

Input sheet 1999

Country Name : Mycountry
Estimate for Company: My Company

Estimate for year ending: 31 December 1999
Group share of expectation sales volumes excluding royalty in kind.

Group interest in company is 100.00%

	Oil	NGL	Gas sm3	Gas Nm3
Minority interest %	0.00%	0.00%	0.00%	0.00%

	1999 - Input			
	Oil 10^6 m³	NGL 10^6 m³	Gas 10^9 std. m³ (tel quel)	Gas 10^9 Nm³ (9500 kcal /Nm³)
Expectation estimate of reserves at 1.1.1999	0.00	0.00	0.000	0.000
New Fields/Discoveries	0.00	0.00	0.000	
Extensions	0.00	0.00	0.000	
Terms & Conditions				
Purchases in place				
Sales in place				
Improved recovery (to/from SFR)	0.00	0.00	0.000	
Economic revisions				
Technical revisions				
Production (sales) during 1999	0.00	0.00	0.000	0.000
Expectation estimate of reserves at 31.12.1999	0.00	0.00	0.000	0.000
Exp. est. of reserves within licence at 1.1.1999	0.00	0.00	0.000	0.000
Net changes in expectation	0.00	0.00	0.000	0.000
Transfer to post licence	0.00	0.00	0.000	0.000
Exp. est. of reserves within licence at 31.12.1999	0.00	0.00	0.000	0.000
Developed reserves within licence at 1.1.1999	0.00	0.00	0.000	0.000
Transfer Undeveloped Reserves to Developed				
Revisions				
Production (sales) during 1999	0.00	0.00	0.000	0.000
Developed reserves within licence at 31.12.1999	0.00	0.00	0.000	0.000
<check Dev Exp> Exp Res	OK	OK	OK	OK
<check Dev Exp> Dev Exp Res	OK	OK	OK	OK
Commited gas 31.12.1999				
Committable gas reserves at 31.12.1999			0.000	0.000
Minority Exp Res. Within Licence included 1.1.1999	0.00	0.00	0.000	0.000
Minority Exp Res. Within Licence included 31.12.1999	0.00	0.00	0.000	0.000

All figures input for Standardized Measure calculation.

Comments:

Expectation comments:

Date: 05-Nov-99

Signed by --- ---

Summary of Resources by Field

Annual Resource Reporting - Summary of Resources by Field
Input sheet (part 1) 1999
Country Name : Mycountry
Estimate for Company: My Company

Note : small fields can be rolled-up by area/contract (less 10% of total)

Estimate for year ending: 31 December 1999
Group share of resource volumes (excluding royalty in kind)

Oil

Field Name	Location	Area/ Contract	Operated	Group Share (% exp)	Oil Quality (Deg. API)	Check Input Loc, Oper & share	(mln m3) Cum Prod	Proved Reserves Dev	Proved Reserves Undev	Exp Res wl Science Dev	Exp Res wl Science Undev	Expectation Reserves Dev	Expectation Reserves Undev	Commercial SFR Proved Tech.	Commercial SFR Unproved Tech.	Commercial SFR Undisc	SFR Non-Com
Other small fields						Enter Error											
Total							0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Check Summary Oil	Missing Data	Missing Data	Missing Data	Missing Data	Missing Data			OK	OK	OK	OK total exp:		OK	OK	OK	OK	OK

NGL

Field Name	Location	Area/ Contract	Operated	Group Share (% exp)	Oil Quality (Deg. API)	Check Input Loc, Oper & share	(mln m3) Cum Prod	Proved Reserves Dev	Proved Reserves Undev	Exp Res wl Science Dev	Exp Res wl Science Undev	Expectation Reserves Dev	Expectation Reserves Undev	Commercial SFR Proved Tech.	Commercial SFR Unproved Tech.	Commercial SFR Undisc	SFR Non-Com
Other small fields						Enter Error											
Total							0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Check Summary NGL	Missing Data	Missing Data	Missing Data	Missing Data	Missing Data			OK	OK	OK	OK total exp:		OK	OK	OK	OK	OK
Total Oil/NGL							0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Annual Resource Reporting - Summary of Resources by Field
Input sheet (part 2) 1999
Country Name : Mycountry
Estimate for Company: My Company

Note : small fields can be rolled-up by area/contract (less 10% of total)

Estimate for year ending: 31 December 1999
Group share of resource volumes (excluding royalty in kind)

Gas - Associated

Field Name	Location	Area/ Contract	Operated	Group Share (% exp)	GHV (kcal/sm3)	Committed (%) exp res wl L	(mrd sm3) Cum Prod	Proved Reserves Dev	Proved Reserves Undev	Exp Res wl Science Dev	Exp Res wl Science Undev	Expectation Reserves Dev	Expectation Reserves Undev	Commercial SFR Proved Tech.	Commercial SFR Unproved Tech.	Commercial SFR Undisc	SFR Non-Com
Other small fields						0.0%				0.00	0.00						
Total					0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Check				Missing Data	Missing Data												

Gas - Non-Associated

Field Name	Location	Area/ Contract	Operated	Group Share (% exp)	GHV (kcal/sm3)	Committed (%) exp res wl L	(mrd sm3) Cum Prod	Proved Reserves Dev	Proved Reserves Undev	Exp Res wl Science Dev	Exp Res wl Science Undev	Expectation Reserves Dev	Expectation Reserves Undev	Commercial SFR Proved Tech.	Commercial SFR Unproved Tech.	Commercial SFR Undisc	SFR Non-Com
Other small fields																	
Total					0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Check				Missing Data	Missing Data												
Total Gas (Non Ass & Ass)					0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Check Summary Gas						OK		OK	OK	OK	OK total exp:		OK	OK	OK	OK	OK

Total of field resources by category should be equal to the total resources reported at company level for the specific resource category.

Note: for "Location" please enter/select: 'Onshore', 'Offshore' or 'Deepwater'.
for "Operated" please enter/select: 'Operated' or 'non-Operated'.

Internal reporting: Expectation Estimate of Scope for Recovery: Oil

Input sheet Oil 1999

Country Name : Mycountry
Estimate for Company: My Company

Estimate for year ending: 31 December 1999
Group share of scope for recovery

	Including potential entitlement after licence expiry				Within licence
	Com. SFR Proved	Com. SFR Unproved	Com. SFR Undisc.	SFR Non Com.	SFR Tot Com.
	10^6m^3	10^6m^3	10^6m^3	10^6m^3	10^6m^3
Expectation estimate of SFR 1.1.1999	0.00	0.00	0.00	0.00	0.00
New Entries					
Discoveries			0.00		
Terms & Conditions					
Purchases in place					
Sales in place					
Transfer to/from reserves	0.00	0.00	0.00	0.00	0.00
Economic revisions					
Technical revisions					
Deletions					
Expectation estimate of SFR 31.12.1999	0.00	0.00	0.00	0.00	0.00
Check	OK	OK	OK	OK	OK
Transfer SFR to/from Reserves	0.00	0.00	0.00	0.00	0.00
New Fields/Discoveries			0.00		
Extensions					
Other to/from Reserves (Imp. Rec.)					

Comments:

SFR Oil comments:

Note:

For oil fields associated gas volumes should be included if oil SFR is carried (also for undiscovered SFR)

Date: 05-Nov-99
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Internal reporting: Expectation Estimate of Scope for Recovery: NGL

Input sheet NGL **1999**

Country Name : Mycountry
Estimate for Company: My Company

Estimate for year ending: 31 December 1999
Group share of scope for recovery

	Including potential entitlement after licence expiry				Within licence
	Com. SFR Proved	Com. SFR Unproved	Com. SFR Undisc.	SFR Non Com.	SFR Tot Com.
	10^6m^3	10^6m^3	10^6m^3	10^6m^3	10^6m^3
Expectation estimate of SFR 1.1.1999	0.00	0.00	0.00	0.00	0.00
New Entries					
Discoveries.			0.00		
Terms & Conditions					
Purchases in place					
Sales in place					
Transfer to/from reserves	0.00	0.00	0.00	0.00	0.00
Economic revisions					
Technical revisions					
Deletions					
Expectation estimate of SFR 31.12.1999	0.00	0.00	0.00	0.00	0.00
Check	OK	OK	OK	OK	OK
Transfer SFR to/from Reserves	0.00	0.00	0.00	0.00	0.00
New Fields/Discoveries			0.00		
Extensions					
Other to/from Reserves (Imp. Rec.)					

Comments:

SFR NGL comments:

Note:

For Gas fields associated NGL volumes should be included if Gas SFR is carried (also for undiscovered SFR)

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Appendix 1
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Internal reporting: Expectation Estimate of Scope for Recovery: Gas

Input sheet Gas **1999**

Country Name : Mycountry
Estimate for Company: My Company

Estimate for year ending: 31 December 1999
Group share of scope for recovery

	Including potential entitlement after licence expiry				Within licence
	Com. SFR Proved	Com. SFR Unproved	Com. SFR Undisc.	SFR Non Com.	SFR Tot Com.
	10^9 std. m^3	10^9 std. m^3	10^9 std. m^3	10^9 std. m^3	10^9 std. m^3
Expectation estimate of SFR 1.1.1999	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
New Entries					
Discoveries			0.000		
Terms & Conditions					
Purchases in place					
Sales in place					
Transfer to/from reserves	0.000	0.000	0.000	0.000	0.000
Economic revisions					
Technical revisions					
Deletions					
Expectation estimate of SFR 31.12.1999	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
Check	OK	OK	OK	OK	OK
Transfer SFR to/from Reserves	0.000	0.000	0.000	0.000	0.000
New Fields/Discoveries			0.000		
Extensions					
Other to/from Reserves (Imp. Rec.)					

Comments

SFR Gas comments:

Note:

For Gas fields associated NGL volumes should be included if Gas SFR is carried (also for undiscovered SFR)

Date: 05-Nov-99

Signed by — —

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