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 (payable in kind).

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

Where royalty is payable in cash or is in principle payable in kind but the government has formally elected to receive, or customarily receives, payment in cash, Group share of production and reserves should be reported 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 of infrastructure (e.g. pipeline tariff, processing fee). Such volumes received by the company 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 Third Party gas volumes and sold by the company are equivalent to fees in kind received. All fees in kind received should be included as a purchased volume in the company accounts.

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

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

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

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

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

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

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

Gas Re-injection Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservation, Underground Gas Storage (UGS) incl. cushion gas, or other reasons, remain part of a company's resource base and should be accounted for as such. These gas volumes should be classified and reported as reserves or SFR, conform any other gas resource based on project 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 Third Party (including any gas volumes previously sold by the company to this party) do not 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 from "oil sands" (tar sand, oil shales, coals etc.) as part of hydrocarbon resources (reserves or SFR) is principally governed by the method of recovery of such volumes. Volumes produced through wells, generally from thermal methods are reported as part of the hydrocarbon resource base. Volumes recovered though mining and subsequently recovered from the mined product are not part of the hydrocarbon resource base and should be reported 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.

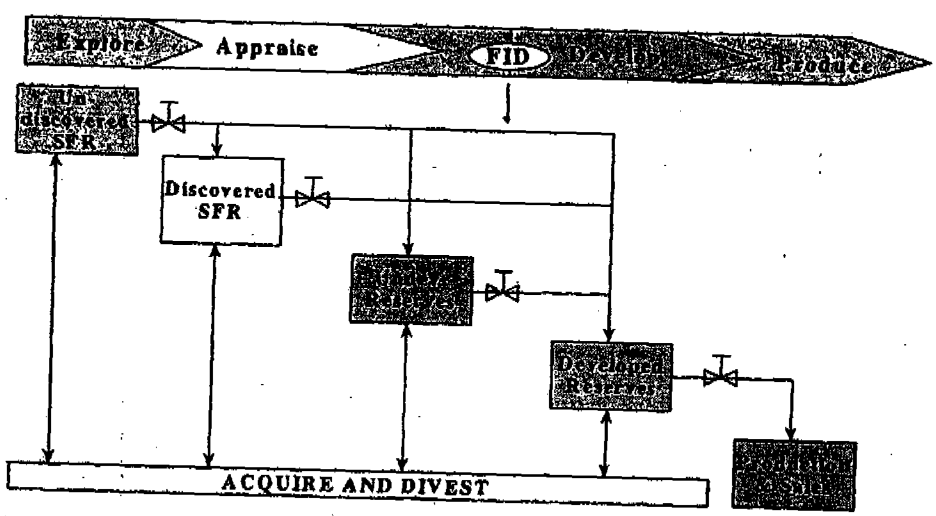

Figure 2: Cascade Model

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 internal classification scheme tied to the development life cycle is to enable understanding of the potential value and the actions needed to mature volumes. In order to achieve business growth and reserves replacement objectives, it is essential that OUs and NVOs have efficient systems to move volumes through the value chain from scope for recovery to production and sales as shown in the cascade model.

OUs and NVOs internal reserve management systems should;

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

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

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

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

3.3 Technical and Commercial Maturity

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

Project Basis

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

Technically Mature

For a project to be **technically mature**, information on the resource volume, including its level of uncertainty, is such that an optimal project can be defined with an auditable project development plan, based on a resource and development scenario description, with drilling/engineering cost estimates, a production forecast and economics. The plan may be notional or it may be an analogy of other projects based on similar resources. However, there should be a reasonable expectation that a firm development plan can be matured with time. Projects do not have to have a completed development plan. Successful completion of a Value Assurance Review (VAR) with sufficient definition supports technical maturity.

Commercially Mature

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

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 8).

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. 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 6 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.

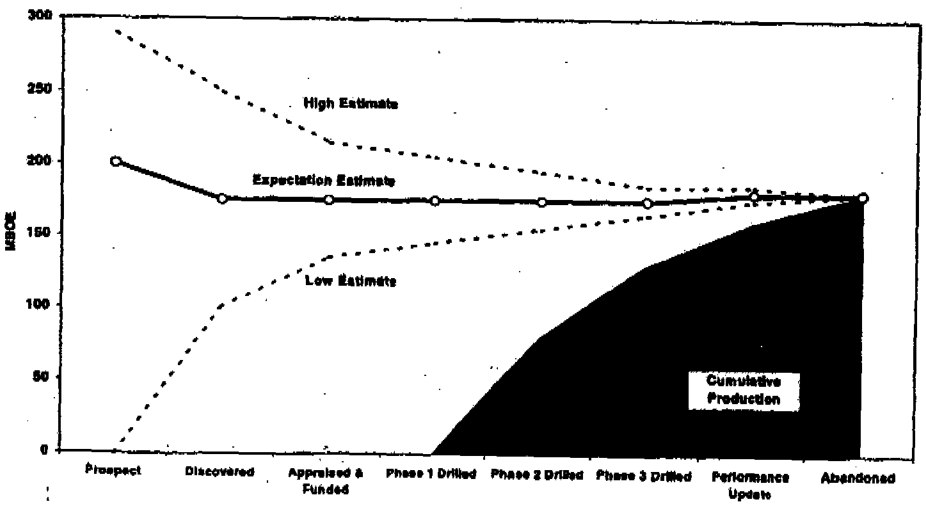

Figure 3: Uncertainty Reduction during the Field Life Cycle

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

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

Addition of Resource Volumes

Resource volumes are added together at various levels during the resource assessment and reporting process. Addition of reserves at or above the level used for depreciation 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 the dependency between the volumes to truly reflect the recoverable volumes associated with a project. Arithmetical addition is appropriate for dependent volumes, but usually overstates the uncertainty range for the sum of partially independent volumes. Probabilistic addition should be used for partially independent volumes when the difference with arithmetic addition is significant.

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

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

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

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

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

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

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[1] Group Accounts should be consulted when considering combining surface facilities for different fields for 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 Production available for Sales (from own reserves) (GPafS) [9130] 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).

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

The 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 definition for gas reserves and the definition for Gas Production available for Sale (GFIM) are fully aligned (both excluding flare/vent and own use).

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 technical 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 or 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 maturing technology from current research, relaxation in the market constraints and/or the terms and conditions for implementing such a project.

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

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

Commercial SFR

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

Commercial SFR by Proved Techniques

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

Commercial SFR by Unproved Techniques

SFR by unproved techniques is the volume believed to be recoverable from discovered resources by a project utilising any recovery technique or process that has not yet been demonstrated to be technically feasible in the field where its application is considered, but which through laboratory or trials elsewhere has a reasonable chance of being technically 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 development, and these SFR volumes must therefore be discounted for the risk that the considered technique will not prove to be feasible.

Undiscovered Commercial SFR

Undiscovered SFR is the volume believed to be recoverable from as yet undrilled potential accumulations by any process that has been a technical success elsewhere, under similar 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 not commercial to develop (Probability of Success, see Appendix 6).

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

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Non-Commercial SFR

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

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

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.

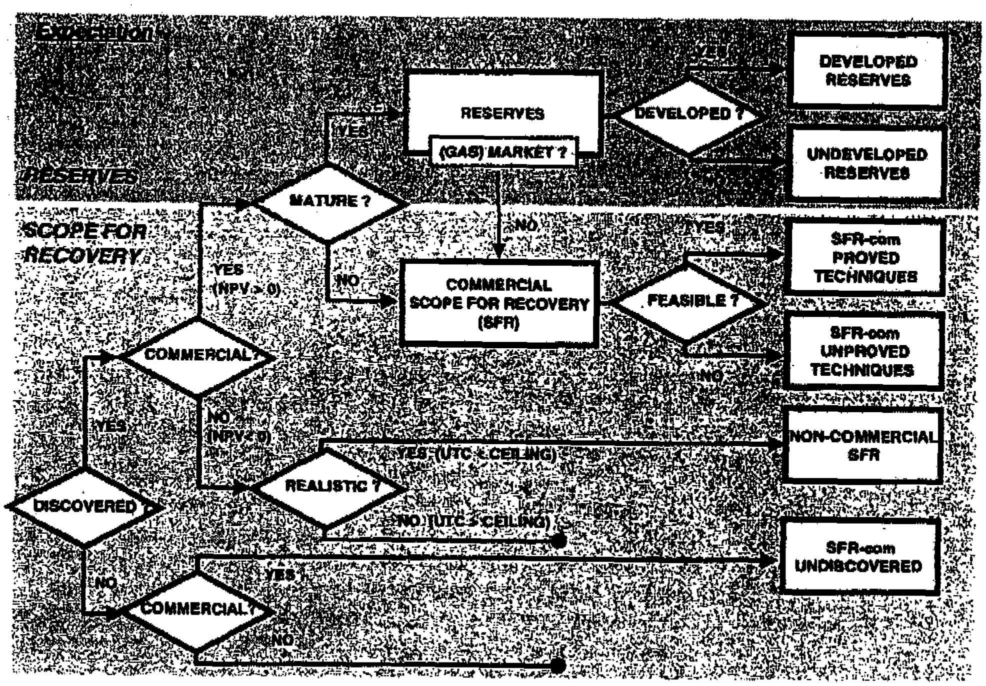


Figure 4: Internal resource classification flow diagram

4. RESOURCE VOLUME CLASSIFICATION FOR EXTERNAL REPORTING

4.1 Classification Scheme

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

The resource categories for external reporting are shown in Figure 5. Cumulative production, total proved reserves and proved developed reserves are externally reported annually for oil, gas and NGL sales quantities as of the 1st of January. The reported volumes must comply with SEC definitions, reproduced in Appendix 3. The Shell Group definitions contained in this section are in full compliance with these definitions. Where Group guidelines interpret SEC definitions, as listed in Appendix 4, these interpretations have been accepted by external auditors as fulfilling SEC requirements. A summary of the Group definitions for the external categories is provided in Appendix 1.

Cumulative Production	
Proved Reserves:	Proved Developed Reserves Proved Undeveloped Reserves

Figure 5: Resource Categories for External Reporting

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

4.2 Proved Reserves

Proved reserves are those reserves that are reported externally[2] and are equal to the portion of reserves, as defined for internal reporting, that is **reasonably certain** to be produced and sold during the remaining period of existing production licences and agreements. Extension periods are only included if there is a legal right to extend, which may derive either from the initial concession agreement or from a subsequent letter of assurance. Any applicable government restrictions on oil export and contractual or practical market limitations to gas delivery rates should be taken into account. Only the Group share of proved reserves is reported.

If probabilistic methods are used, undeveloped 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. Reasonable certainty for developed reserves is the mean value or the base case for probabilistic or scenario deterministic methods respectively.

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

[2] Proved reserves are not by default equal to the P85 or low estimate!

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 (as reported externally) 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 separately and though different methods, after which proved undeveloped reserves are calculated as the difference between the two. In mature fields, where a significant portion of the reserves has 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 7). 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 7). This method first defines the proved area[3] 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.

[3] 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 7).

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.

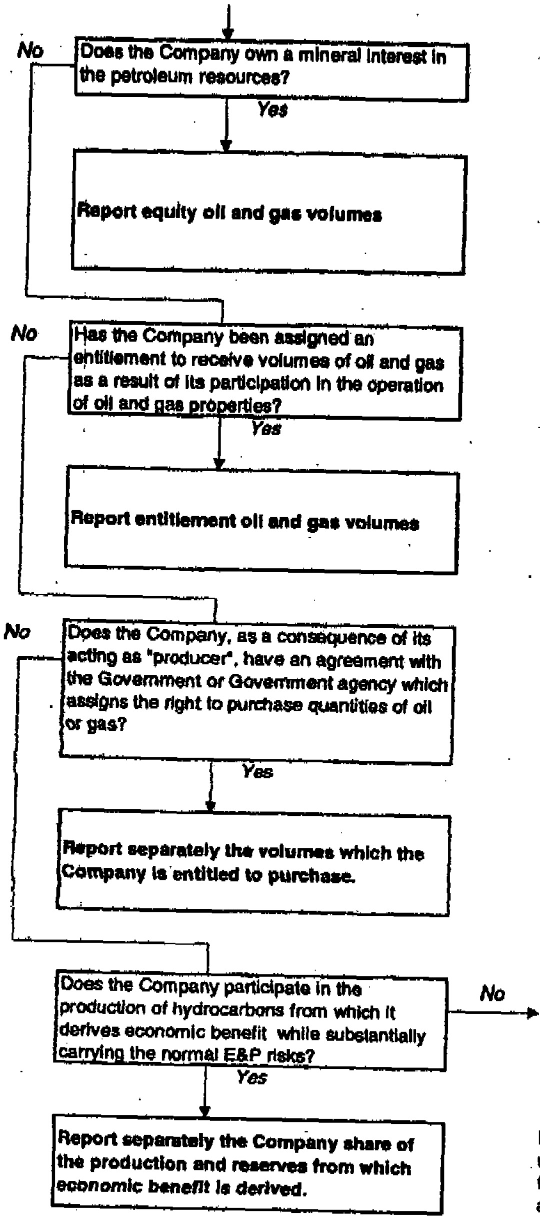
Types of Agreements

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 6.

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.[4]

[4] 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 6: 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 to 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 required 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 technically most appropriate for quantifying the resource volumes of their assets consistent with these guidelines. The preferred methods and systems may vary depending on the type of resource and with time as the resource matures and technology improves.

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

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

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

5.3 Responsibilities and Audit Requirements

EP Planning Responsibilities

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

Reserves Auditor Responsibilities

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

Operating Unit Responsibilities

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

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

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

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 SIEP/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

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

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, SIEP/SEPI should be advised at the earliest opportunity.

Guidelines on how to prepare a good audit trail, with suggested formats for tables etc. can be found on the Shell World Web (Reference 11).

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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
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6. EP92-0945 Business Process Management Guideline, SIPM, EPO/72, June 1992
7. Petroleum Reserves Definitions, Society of Petroleum Engineers and World Petroleum Congresses,
   http://www.spe.org select "oil and gas technology"
8. Project Evaluation and Screening Criteria, SIEP 2000-2030, June 2000
9. Handbook of SEC Accounting and Disclosure
10. Financial Accounting Standards Board (FASB), e.g. Statements 19, 25 and 69.
11. Shell wide web – Resource Management web-page,
   http://sww.sepiv.shell.com/epb_epplan/arpr/resmgt.htm

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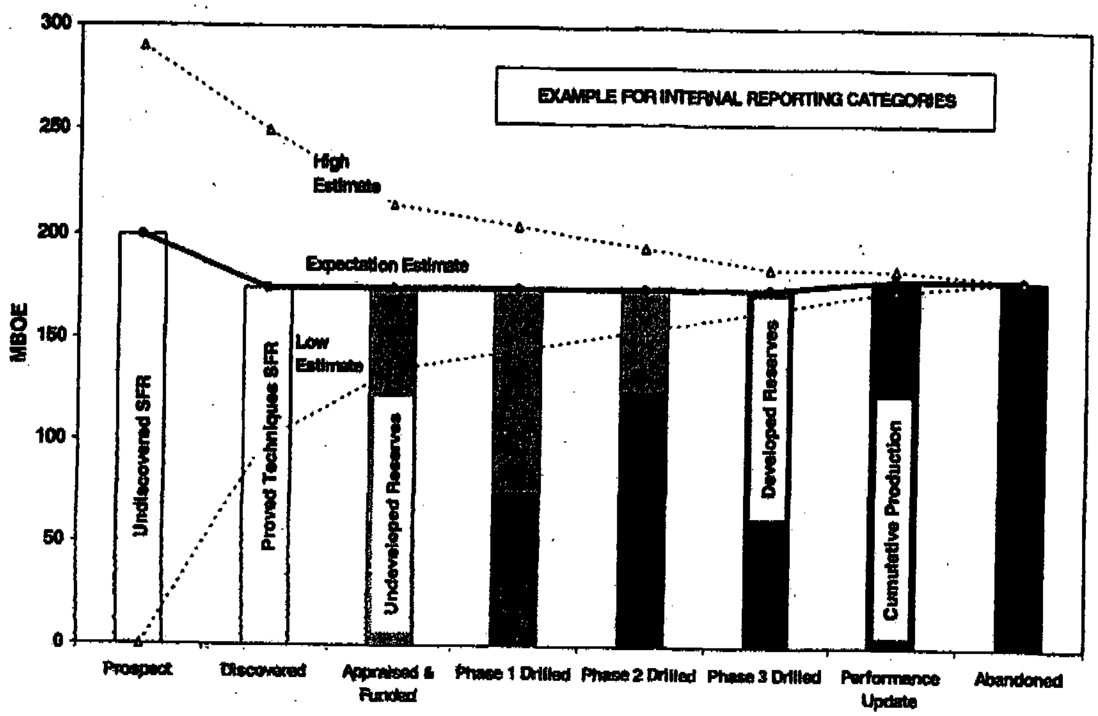
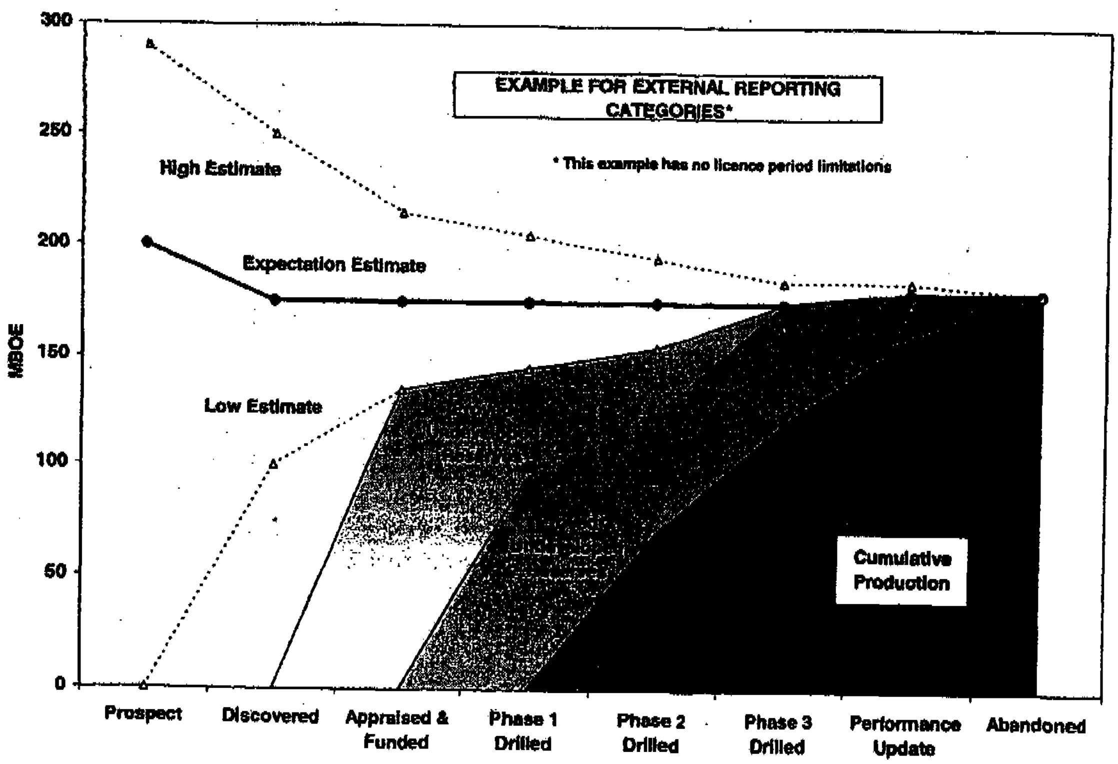
APPENDIX 1: RESOURCE CATEGORY (QUICK REFERENCE)

Reporting	Class	Category	Criteria
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
External Reporting; Internal Reporting	Proved Reserves	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
External Reporting; Internal Reporting	Proved Reserves	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
Internal Reporting	Reserves	Developed Reserves	• Reserves producible through existing completions and installed facilities using existing operation methods • Outstanding project activities considered completed if remaining cost <10% of total
Internal Reporting	Reserves	Undeveloped Reserves	• Reserves which require capital investment (wells and/or facilities)
Internal Reporting	Scope for Recovery		• Project is not technically and/or commercially mature • Not restricted by licence period • Group share reported
Internal Reporting	Scope for Recovery	Commercial SFR by Proved Techniques	• Discovered • Commercially viable • Techniques have been proved to be feasible in this resource • A sound technical project proposal is not possible yet due to large range of technical uncertainty • Market not currently available
Internal Reporting	Scope for Recovery	Commercial SFR by Unproved Techniques	• Discovered • Commercially viable • Recoverable by techniques that have been successful elsewhere, but cannot yet be demonstrated to be feasible in this field • Laboratory work or trials elsewhere have a reasonable chance of demonstrating feasibility in this field • Discounted for the risk that the considered technique will not prove to be feasible
Internal Reporting	Scope for Recovery	Non-Commercial SFR	• Discovered • Not commercially viable even if technically successful • Commercially viable with a change of commercial circumstances • Unit Technical cost below an annually advised ceiling • Remaining tail production if it is significant
Internal Reporting	Scope for Recovery	Undiscovered Commercial SFR	• Recovery from undrilled prospects • Commercially viable exploration and development • Techniques have been successful elsewhere under similar conditions • Discounted for the risk that commercial volumes are not present

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 to F3-64)

Proved Reserves

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

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

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

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

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

1. oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";
2. crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
3. crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
4. crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal (excluding certain coalbed methane gas), gilsonite and other such sources.

Proved Developed Reserves

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

Proved Undeveloped Reserves

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

APPENDIX 4: SHELL INTERPRETATION OF SEC 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.

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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 2000-1100/1101) and the FASB Statement of Financial Accounting Standards no.69 (SFAS-69).

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

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

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

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

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

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

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

APPENDIX 6: TERMINOLOGY

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 NGL, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such 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.

EP 01-1100 01/09

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Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

DEPOSITION EXHIBIT
Barendregt
#7 2/20/07