PDO/Gisco, Oct 2003 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	X	No; The individual proved / expectation reserves ratios for individual fields are too low, particularly for the more mature fields (see Att.4).
5.03	Can reserves changes be reconciled with individual field changes?	X	Changes have been reported in the 'Improved Recovery, 'Extensions and Discoveries', Transfers form Undeveloped to Developed' categories and of course in 'Revisions'. There was no audit trail note to link this back in a quantitative manner to individual fields. The ARPR is in full 30-year life cycle volumes only.
5.04	Are reserves changes reported in the appropriate categories?	X	Since the source of the changes was not clear, it could not be established whether the categorisation of the changes was appropriate.
5.05	Is there a document in place describing the OU's reserves reporting procedures?	O	A document has been in circulation in draft form for some time. A final version is anticipated in November this year.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	O	FDP documents were prepared upon the conclusion of studies. Very few of these have been issued in recent years because of time pressure.
5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	X	Whilst there is a central library with search facilities, field teams tend to keep project reports in personal filing cabinets.
5.08	Is the annual reserves submission supported by a sufficiently detailed summary note explaining the reserves changes (classified in revisions, extensions, sales-in-place etc) per field, with references to detailed reports as appropriate?	X	An ARPR report is issued annually, which lists full life cycle (i.e. 30-years) recoverable volumes of oil+condensate (from PDO facilities) and associated gas. The format seems somewhat cumbersome (duplicated data and unnecessary data e.g. depletion rates, high estimates). It could benefit from a simplification. A note describing the basis for the Group estimates was not present, only a complex spreadsheet.
5.09	Are electronic data bases containing both historic submissions' data and current reserves data in place and accessible?	+	Yes, largely in the form of spreadsheets
5.10	Do these data bases also contain references to detailed reports?	O	No.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes; Oil (and any co-produced oil gas condensate) is reported by PDO, gas and ex-gas plant liquids entitlements are reported by Gisco.
6.03	Are own use, fuel, losses etc excluded?	+	Gas own fuel and losses are not relevant to the calculation of Group share oil entitlements
6.04	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system? (Ceres line 0933, which is the sum of line 7385 (Reward Oil/NGL) and line 0871 [= 8462-Oil + 8464-NGL for Consolidated Companies + line 3596 (= 0931-Oil + 0932-NGL) for Assoc. Companies).	+	Yes
6.05	Are annual gas production volumes in reserves submissions consistent with Upstream Gas production available for Sales (GpafS) volumes reported into the Finance (Ceres) system? (Ceres line 9130).	N.A.	No gas reserves carried by PDO
6.06	Are the Financial and Reserves accounting of production / sales fully consistent with each other also in cases like royalties, fees-in-kind, underlift/overlift, gas re-injection/UGS, take-or-pay gas?	+	Yes (only royalties are applicable here)
6.07	Are the net Shell share reserves reported properly and consistently with Finance reporting (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	+	PDO prepares the submissions as an associated company with 34% Group share.

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+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

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PDO/Gisco, Oct 2003 CHECKLIST SEC RESERVES AUDITS Attachment 3

6.08	Are reported proved total and proved developed reserves consistent with those used for asset depreciation in Group Accounts?	N.A.	PDO has not applied UOP asset depletion in the past. The operating agreement stipulates a 40-30-10-10-10% depreciation profile for all capex and this is applied for calculation of the Shell margin and for tax submissions. Shell Group returns are made by Somant who do not hold any share in the PDO assets, hence no asset depreciation is applicable for Group accounts. PDO accounts are managed with depreciation through the abovementioned 5-year profile. This is not in accordance with International accounting practices, which require UOP depletion, based on proved total and proved developed reserves. This has led to qualifications in external auditor reports, which the Oman Government now want to see removed. Hence, PDO will need to maintain proper estimates of individual field proved developed and proved total (i.e. undeveloped) reserves, probably starting at 1.1.2005.
7	OVERALL		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	X	Group share proved developed reserves at 1.1.2003 are largely acceptable. However, Group share total (i.e. undeveloped) reserves are not in accordance with SEC and Group guidelines and have thus been overstated significantly.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	+	In spite of the above comment, the currently reported volumes give a reasonable reflection of shareholder value if account is taken of the probable extension of the current production licence agreement beyond 2012.

		Weight	Score (0-100%)
1	TECHNICAL MATURITY	30%	47%
2	COMMERCIAL MATURITY	9%	72%
3	REASONABLE CERTAINTY	21%	67%
4	GROUP SHARE CALCULATION	8%	50%
5	AUDIT TRAILS	16%	23%
6	CONSISTENCY WITH FINANCIAL REPORTING	7%	100%
7	OVERALL OPINION	8%	50%
	TOTAL SCORE	100%	54%

DB 28777

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

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SIEP 98-1100

Petroleum Resource Volume Guidelines

Resource Classification and Value Realisation

DEPOSITION EXHIBIT
Barendregt
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SIEP 98-1100

Petroleum Resource Volume Guidelines

Resource Classification and Value Realisation

Custodian : SEPIV-EPB-P
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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). These guidelines, building on the foundation established by previous versions (References 1 to 5), aim to achieve these goals. They 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).

2 PETROLEUM RESOURCES

2.1 Definition

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

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

Resource volumes are tied to the project that develops them and are generally reported by field. The term **reserves** is used for resource volumes associated with a project that is technically mature and commercially viable. Resource volumes that do not meet these criteria are called **scope for recovery** (SFR). **Proved reserves** are the portion of reserves that is reasonably certain to be produced. 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 by agreements with the resource holders. Resource volumes can be distinguished according to three different types of agreement, which are discussed below.

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

Entitlement Entitlement resources are the Group share of production in acreage governed by a Production Sharing Contract (PSC). The Group share of production is the Group interest in 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 innovative production contracts in order to attract investment by foreign oil companies while preserving the principle of national resource ownership. These agreements typically provide for the contractor to recover costs and profits from hydrocarbon revenues while holding no title to, or entitlement to receive, petroleum resources.

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

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

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

volume but paid from oil revenues, the economic value to the OU is in effect derived from the produced gas, and this volume should be reported.

3. The OU 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.

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 para. 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 (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 for the use of infrastructure (e.g. pipeline tariff). Such payments do not constitute a Group share in resources and should not be included in reported volumes.

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.

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:	Proved Techniques Scope for Recovery Unproved Techniques Scope for Recovery Non-Commercial Scope for Recovery
Undiscovered 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.

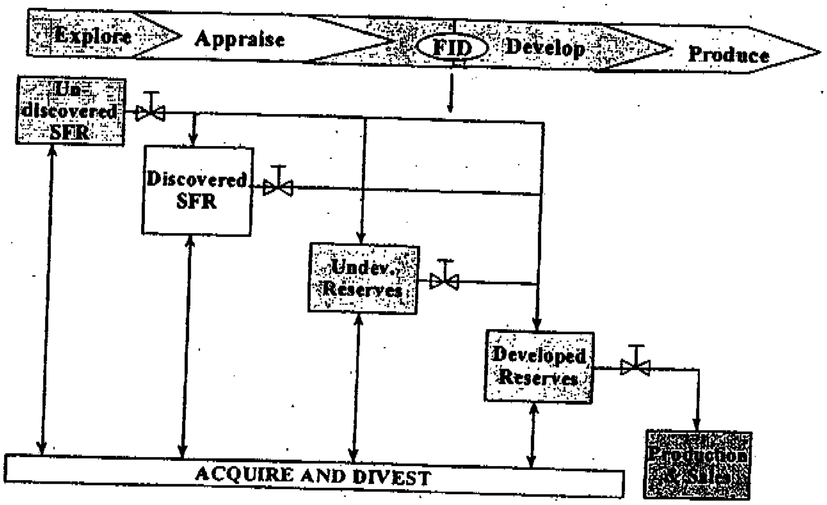

Figure 2: Cascade Model

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 volumes 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. replacement 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 mature and commercially viable. 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, 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.

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. 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.

A scenario is **commercially viable** if the NPV is expected to be positive under the applicable terms and conditions for the acreage and for the current advised Group reference criteria for commerciality (Reference 9).

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

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

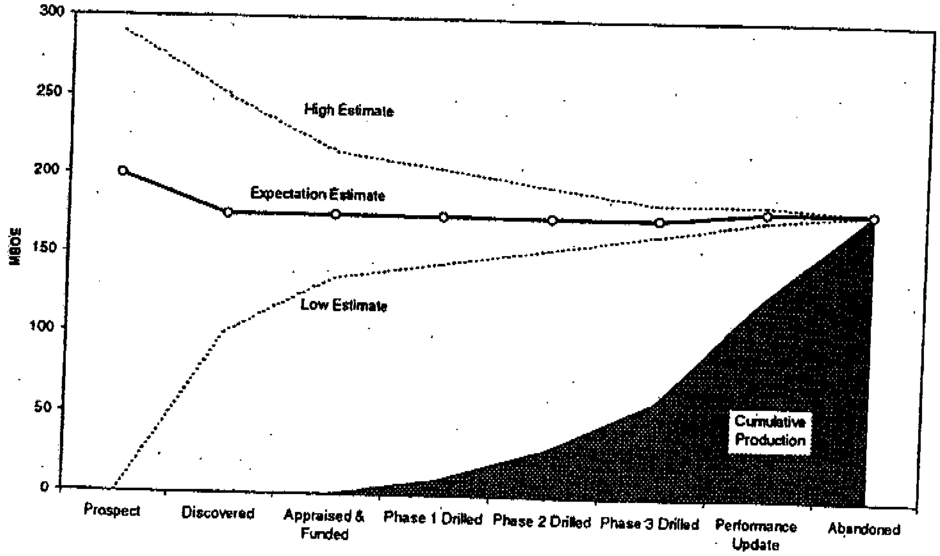

Figure 3: Uncertainty Reduction during the Field Life Cycle

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 mature and commercially viable. 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.

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.

---

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

3.6 Reserves

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

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).

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 significant enough to be marketed).

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

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.

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 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.

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 calculations and investor assessments. The reported figures are used to calculate the depreciation of EP sector 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 volumes are a true reflection of shareholder value.

The resource categories for external reporting are shown in Figure 4. 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 4: 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 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, 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.

As discussed in Section 2.4, proved reserve estimates should be updated annually based on 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.

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.

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.

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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).

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.

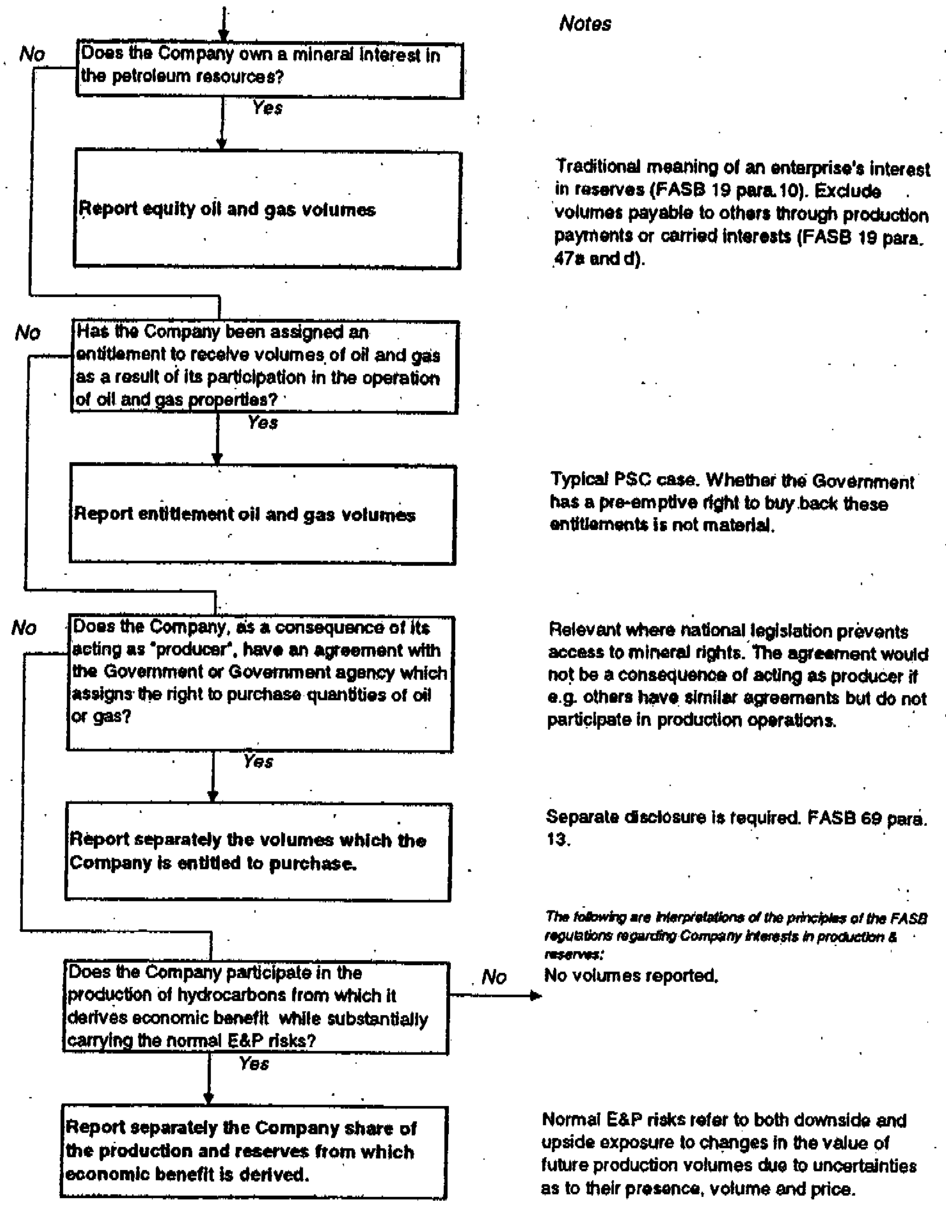

Figure 5: Types of External Disclosures in Relation to FASB Regulations

5. RESOURCE VOLUME REPORTING, RESPONSIBILITIES AND AUDITS

5.1 Shareholder Requirements

EP Planning will communicate a timetable and the details about submission requirements 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. Best practices will be developed, updated and shared in the Hydrocarbon Resource Volumes Management Common Interest Network (Reference 7). This network will replace the material previously covered in Volume 2 of the 1988 guidelines (Reference 1).

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.

5.2 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 SIEP.

Annual Review of Petroleum Resources

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

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, SIEP should be advised at the earliest opportunity.

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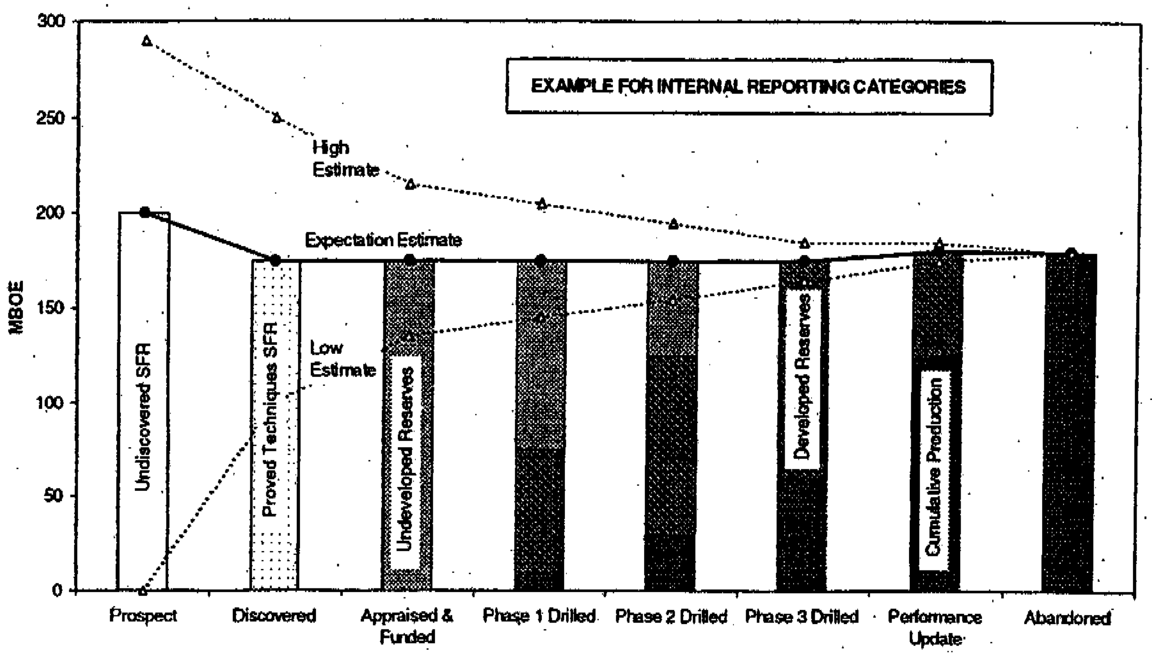
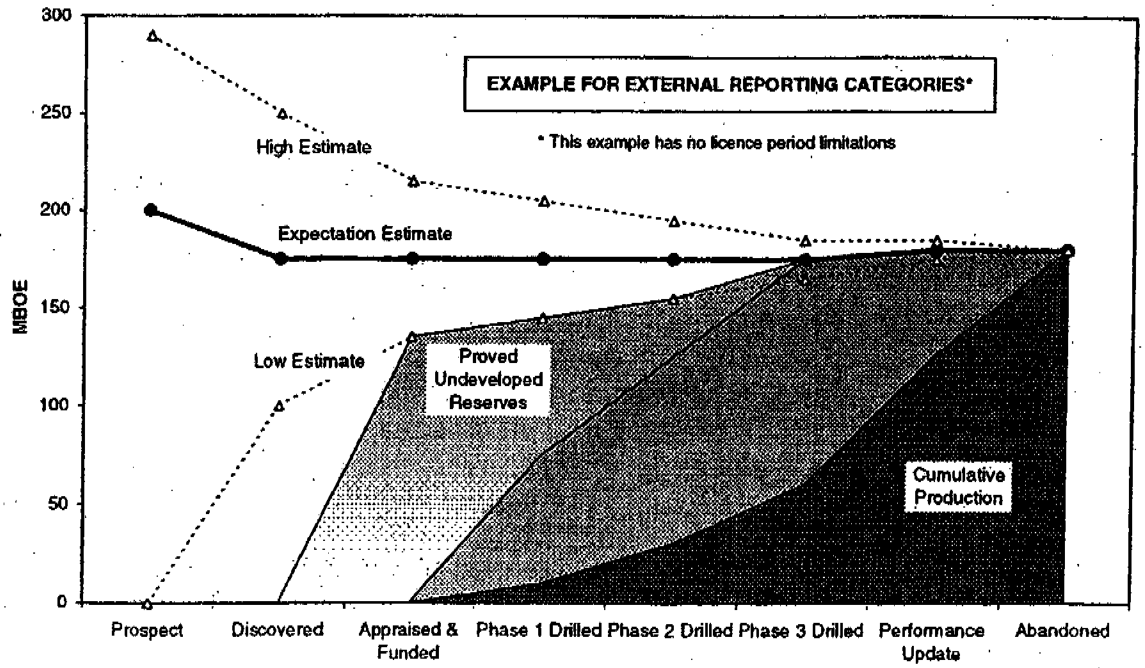
APPENDIX 1: RESOURCE CATEGORY DEFINITIONS SUMMARY

Internal Reporting	**Reserves**		• Project is "technically and commercially mature" (defined in section 3.3) • 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 and installed facilities using existing operation methods • Outstanding project activities considered completed if <10% of total
		Undeveloped Reserves	• Reserves which require capital investment (wells and/or facilities)
	Scope for Recovery		• Project is <u>not</u> technically and commercially mature • Not restricted by licence period • Group share reported
		Proved Techniques SFR	• 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
		Unproved Techniques SFR	• 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 technically feasibility in this field • Discounted for the risk that the considered technique will not prove to be feasible
		Non-commercial SFR	• Discovered • Not commercially viable even if technically successful • Commercially viable with a change of commercial circumstances • Unit Technical cost below an annually advised ceiling • Remaining tail production if it is significant
		Undiscovered SFR	• Recovery from undrilled prospects • Commercially viable • Techniques have been successful elsewhere under similar conditions • Discounted for the risk that commercial volumes are not present
External Reporting	**Proved Reserves**		• Portion of reserves as defined above that are reasonably certain • Discounted for undefined fluid contacts and untested recovery mechanisms • Restricted by licence periods, government constraints and market limitations • External financing, when used, must be expected to be available
		Proved Developed Reserves	• Reserves producible through existing completions and installed facilities using existing operation methods • Outstanding project activities considered completed if <10% of total
		Proved Undeveloped Reserves	• Reserves which require capital investment (wells and/or facilities)

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.
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 is reasonably expected.

APPENDIX 5: SEC AUDIT - TERMS OF REFERENCE

The Auditor's task is the following:

1. Establish whether the reserves estimates for external reporting have been prepared in accordance with the established guidelines. If not, to establish that the procedures used are acceptable, and not likely to result in reserves estimates that differ from those that might be expected from the application of the standard guidelines.
2. Establish that the basis for estimating the reserves quantity information is consistent with the previous periods.
3. Check that the source data is adequately documented and that movements in proved reserves are supported by such data and are correctly classified.
4. Establish that the frequency and extent of the reserves estimates are sufficient to make the estimates continuously reliable.
5. Investigate any differences between volumes that are reported for external purposes and those that are reported to SIEP in annual financial reporting.
6. Check the calculation of proved developed reserves and investigate any differences between proved developed reserves used for external purposes and those used as a basis for asset depletion purposes.
7. Establish whether proved gas reserves agree with sales contracts concluded.
8. Ensure that all quoted proved reserves are expressed in sales quantities, e.g. own use has been excluded. In case of gas sales the production quantity should be given as measured at the point of transfer.
9. Ensure that sales quantities of hydrocarbons are in line with those reported to Finance.

The checks will be carried out by taking at random one or more fields for detailed analysis, and a judgement will be passed accordingly.

The audit will be carried out as a stand alone exercise based on documentation available in the company to be investigated. In case of queries assistance of company staff may be called upon.

An audit report will be prepared on site (draft) and discussed locally. The report will contain an Action List based on recommendations of the report.

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 variate indicates the probability that the actual variate 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 variate 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.

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Aalbers, Remco RD SIEP-EPB-P

From: Meijssen, Thomas OQP
Sent: 03 January 2001 08:51
To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Anton, Remco,

Many thanks for your Email. Based on the guidelines given in your Email below, we have evaluated the impact on the proven reserves numbers to be used for external reporting using the notional ARPR 1/1/2001 data.

In the table below, a breakdown of the total expected reserves (developed and undeveloped) versus maturity (as expressed in cumulative production / expected recovery) has been given. As can be observed from the table, 61% of the total expected reserves can be classified as mature, using the 40% criterion.

Maturity	Tot Res	%
<40%	305	39%
40-60%	227	29%
>60%	255	32%
Total expectation	787	100%

All volumes 100% PDO, mln m3

MNI = 192.8 1/1/2001

An overview of the proven and expected reserves as carried by PDO and the impact of using the Shell Group guidelines on externally reported proven reserves has been indicated in the table below.

~~Proven~~ P85	DevRes	UndevRes	TotRes	Incr	Incr %
Proved 1999 method	205	220	425		
Proven, DevRes 40%	380	46	425	0	0%
Proven, DevRes 40%, UndevRes 60%	347	220	567	141	33%
Proven, DevRes 40%, UndevRes 40%	347	254	601	176	41%
Expectation	347	304	651	225	53%
	380	408	787		

All volumes 100% PDO, mln m3

52% 52% 52%

144.5 ~ 35% ~~144.6~~ 137.3

→ 192.8 55 @ 34%

90% = ~~[illegible]~~ 1735

Some remarks: P85

- The ~~proven~~ and expectation reserves are as per the reserves bookings, the expected developed reserves are updated annually using the do-nothing production forecast. The proven developed reserves are calculated by pro-rating the proven/expectation reserves and expected developed reserves.
- ~~Proven~~ P85: ~~Proven~~ P85 reserves as carried by PDO at 1/1/2001
- Expecation: Expected reserves as carried by PDO at 1/1/2001
- Proven, 1999 method: Proven reserves, making proven developed reserves equal to expectated developed reserves for all fields ~~exceeding 40% maturity~~, but keeping the total proven reserves equal. As a result the proven undeveloped reserves reduces to 46 mln m3 which seems unrealistically low.
- Proven, DevRes 40%: Proven reserves, making proven developed reserves equal to expectated developed reserves for fields exceeding 40% maturity, keeping the proven undeveloped reserves equal.
- Proven, DevRes 40%, UndevRes 60%: As above, but in addition now making the proven undeveloped reserves equal to the expected undeveloped reserves for fields exceeding 60% maturity (more relaxed criterion, to reflect the additional uncertainty related to the undeveloped reserves).
- Proven, DevRes 40%, UndevRes 40%: As above, but using the 40% maturity criterion for undeveloped reserves.

I would propose for external reserves reporting to only adjust the proven developed reserves using the 40% maturity criterion and to keep the undeveloped reserves for internal and external reporting the same (case: Proven, DevRes 40%). As a result the total proven reserves increases by 141 mln m3 (100% PDO). Any further increase in total proven reserves becomes more difficult to argue in view of the additional uncertainty of the undeveloped reserves which is difficult to quantify.

Would you agree with the proposed method? Following your advise, I will inform PDO senior management on the proposed method for external reserves reporting to the Shell Group.

Best regards,

DEPOSITION EXHIBIT Barendregt #29 2/22/07

FOIA Confidential Treatment Requested RJW00151703

DEPOSITION EXHIBIT Aalbers D 2/19/07

Thomas

-----Original Message-----
From: Barendregt, Anton AA SIEP-EPB-GRA
Sent: 02 January 2001 16:05
To: Meijssen, Thomas TEM PDO-OQP / UPR
Cc: Aalbers, Remco RD SIEP-EPB-P; Abri, Said SM PDO-CEM3; Antonini, Marcus MCJ PDO-CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Thomas,

In response to your query, I fully support the conclusions reached during Remco's visit, as reflected in your note of 24th October. In particular, I support the move towards using expectation estimates for the externally reported proved reserves for mature fields (i.e. for fields with cum.prod. greater than 40% of expectation ultimate recovery). I note that the 40% criterion is not necessarily rigorous: for simple clastic light oil waterdrive reservoirs it could easily be set lower, for heavy oil reservoirs or complex carbonate reservoirs like many of those in Oman, it seems a realistic proposition.

As mentioned in my 1999 audit report (Att. 3) we should move away from determining total proved reserves through probabilistic volumetrics, combined with probabilistic estimates of recovery factors. Instead we should make separate estimates of developed reserves (from decline analysis or history matched reservoir simulation) and undeveloped reserves (from reservoir simulation or other reliable predictions). Undeveloped reserves must always be based on a well defined set of future activities (new wells, infill drilling, re-completions etc.).

Each of the two volumes (i.e. developed and undeveloped reserves) can have a probability range (P85, P50, P15, Expectation) associated with it. Group guidelines prescribe that for developed reserves in mature fields we should take the Expectation estimate as the externally reported 'Proved Developed Reserves'. For those mature fields it is expected that the P85 estimate would be close to the P50/Expectation value anyway. For externally reported undeveloped reserves it will often be appropriate to take the expectation value as well, but in some of the more uncertain cases (e.g. different future well types) it may be more appropiate to take the P85 volume.

The externally reported total reserves should be the sum of the developed and the undeveloped reserves estimates.

Trust this clarifies. Good luck with your 2000 submission!

Last but no least, I wish yourself and the PDO PE community a successful, safe and healthy 2001!

Anton Barendregt

-----Original Message-----
From: **Meijssen, Thomas OQP**
Sent: 22 December 2000 14:36
To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: FW: Proved Reserves Visit - Group Resource Co-ordinator

Anton,

With reference to the visit of Remco Aalbers to PDO from 23-24 October 2000, we would like to know your opinion with respect to external reporting of proven reserves. During the visit of Aalbers the following was suggested:

External reporting of proved reserves in line with Group guidelines will be handled by PDO reserves co-ordinator and the CFDH reservoir engineering. It is recommended to use field maturity in excess of 40% (as expressed in cumulative production / expected recovery) as the criterion to use proved developed = expectation developed. As a result the total proved reserves will similarly increase. This procedure will be further clarified with Group Reserve Auditor Anton Barendregt. **Action: CEM/3, UPR**

Looking forward to your reply,

Best regards,

Thomas Meijssen
CFDH Reservoir Engineering

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RJW00151704

DEPOSITION EXHIBIT
Aalbers # E
2/19/07 (7a)

-----Original Message-----
From: Barendregt, Anton AA SIEP-EPB-GRA
Sent: donderdag 4 januari 2001 13:51
To: Meijssen, Thomas TEM PDO-OQP / UPR
Cc: Aalbers, Remco RD SIEP-EPB-P; Abri, Said SM PDO-CEMO; Antonini, Marcus MCJ PDO-CEMS
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Thomas,

Remco and I have looked at your proposed figures and our comment is as follows:

1. The ratio between your total P85 and expectation reserves (425 and 787 mln m3 respectively) is 54%. This is far too low for a mature area like Oman and indicates that there are fundamental flaws in PDO's present process of calculating the probabilistic range of ultimate recovery in its fields. In essence, it seems that the ranges of volumetric and RF parameters are taken far too wide, as if they applied to virgin fields instead of fields with large numbers of wells and extensive production history. The result is that P85 UR volumes are not increased in line with production performance history. This flaw was highlighted during the 1999 SEC reserves audit and again during Remco's visit in October 2000.
2. Having said that, we appreciate that updating field P85 recoveries to more realistic levels requires discussion with the Ministry and hence may take time. We suggest that priorities are set if necessary, aiming at updating the P85 volumes first for the largest fields
3. We stress again that the issue of what reserves to report as 'Proved, externally reported' is, since the 1998 changes in the reserves guidelines, quite different from the issue of what reserves to carry as P85 or Low volumes for individual fields. The latter may be subject to discussion with the Ministry, but the first cannot be, if only because the total PDO Shell share volume has to be curtailed at licence expiry, an issue that does not interest the Ministry.
4. In order to avoid confusion, also internally within PDO, it may be opportune to reserve the term 'Proved' exclusively for the externally reported Proved reserves and use 'P85' or 'Low' (NOT 'Proven') for the high confidence reserves values. We'll consider whether this distinction can perhaps be made more clearly in future versions of the Guidelines.
5. As for your proposed volumes to book as externally reported Proved Reserves (before they are cut off by licence expiry), your line "Proven, DevRes 40%, UndevRes 60%" (347 mln m3 Dev Res and 254

DEPOSITION EXHIBIT (7a)
Barendregt
#30 2/22/07

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UndevRes) seems the best one to aim for. It is still conservative (because of the too low P85 values in the less mature fields), but it has the advantage that one can maintain this method of determining externally reported Proved reserves in future submissions. Any future over-reporting of undeveloped reserves (i.e. in fields where undeveloped reserves are still somewhat uncertain in spite of the field's maturity) is compensated by the fact that we take expectation only for fields in excess of 60% maturity (and not 40%) and P85 for those below 60%.

6. As mentioned, externally reported Proved reserves must be cut off at licence expiry through a realistic forecast. For the recommended case "Proven, DevRes 40%, UndevRes 60%" we estimate a 9-year plateau plus subsequent decline (@20%), leading to a Proved volume after licence expiry cut off (but before 34% Shell share) of some 87% of 347+254 mln m3, i.e some 523 mln m3. Shell share would then be 178 mln m3 1/1/2001, versus 139.5 mln m3 1/1/2000, an increase of some 55 mln m3 (assuming 2000 prod is some 16.5 mln sm3).
7. This method results in a proved/exp dev ratio of 347/380 = 91% and a proved/exp undev ratio for 254/408 = 62% (PDO), values that are much more in line with the maturity of the Oman fields, even if the undev ratio is still too low.

We hope the above clarifies. Please let us know if you have further queries.

Best regards,

Anton

-----Original Message-----
From: Meijssen, Thomas OQP
Sent: 03 January 2001 09:59
To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Anton, Remco,

Please note that the 1999 method used for external reporting made the proven developed reserves equal to expectated developed reserves for <u>all</u> fields (irrespective of their maturity) and kept the total proven reserves equal.

Best regards,

Thomas

-----Original Message-----
From: Meijssen, Thomas OQP
Sent: 03 January 2001 12:52
To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Anton, Remco,

Many thanks for your Email. Based on the guidelines given in your Email below, we have evaluated the impact on the proven reserves numbers to be used for external reporting using the notional ARPR 1/1/2001 data.

In the table below, a breakdown of the total expected reserves (developed and undeveloped) versus maturity (as expressed in cumulative production / expected recovery) has been given. As can be observed from the table, 61% of the total expected reserves can be classified as mature, using the 40% criterion.

<< OLE Object: Microsoft Excel Worksheet >>

An overview of the proven and expected reserves as carried by PDO and the impact of using the Shell Group guidelines on externally reported proven reserves has been indicated in the table below.

<< OLE Object: Microsoft Excel Worksheet >>

Some remarks:

- The proven and expectation reserves are as per the reserves bookings, the expected developed reserves are updated annually using the do-nothing production forecast. The proven developed reserves are calculated by pro-rating the proven/expectation reserves and expected developed reserves.
- Proven: Proven reserves as carried by PDO at 1/1/2001

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- Expecation: Expected reserves as carried by PDO at 1/1/2001
- Proven, 1999 method: Proven reserves, making proven developed reserves equal to expectated developed reserves for fields exceeding 40% maturity, but keeping the total proven reserves equal. As a result the proven undeveloped reserves reduces to 48 mln m3 which seems unrealistically low.
- Proven, DevRes 40%: Proven reserves, making proven developed reserves equal to expectated developed reserves for fields exceeding 40% maturity, keeping the proven undeveloped reserves equal.
- Proven, DevRes 40%, UndevRes 60%: As above, but in addition now making the proven undeveloped reserves equal to the expected undeveloped reserves for fields exceeding 60% maturity (more relaxed criterion, to reflect the additional uncertainty related to the undeveloped reserves).
- Proven, DevRes 40%, UndevRes 40%: As above, but using the 40% maturity criterion for undeveloped reserves.

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Would you agree with the proposed method? Following your advise, I will inform PDO senior management on the proposed method for external reserves reporting to the Shell Group.

Best regards,

Thomas

-----Original Message-----
From: Barendregt, Anton AA SIEP-EPB-GRA
Sent: 02 January 2001 16:05
To: Meijssen, Thomas TEM PDO-OQP / UPR
Cc: Aalbers, Remco RD SIEP-EPB-P; Abri, Said SM PDO-CEM3; Antonini, Marcus MCJ PDO-CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Thomas,

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The externally reported total reserves should be the sum of the developed and the undeveloped reserves estimates.

Trust this clarifies. Good luck with your 2000 submission!

Last but no least, I wish yourself and the PDO PE community a successful, safe and healthy 2001!

Anton Barendregt

-----Original Message-----
From: Meijssen, Thomas OQP
Sent: 22 December 2000 14:36

OM 000207

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To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: FW: Proved Reserves Visit - Group Resource Co-ordinator

Anton,

With reference to the visit of Remco Aalbers to PDO from 23-24 October 2000, we would like to know your opinion with respect to external reporting of proven reserves. During the visit of Aalbers the following was suggested:

External reporting of proved reserves in line with Group guidelines will be handled by PDO reserves co-ordinator and the CFDH reservoir engineering. It is recommended to use field maturity in excess of 40% (as expressed in cumulative production / expected recovery) as the criterion to use proved developed = expectation developed. As a result the total proved reserves will similarly increase. This procedure will be further clarified with Group Reserve Auditor Anton Barendregt. **Action: CEM/3, UPR**

Looking forward to your reply,

Best regards,

Thomas Meijssen
CFDH Reservoir Engineering

Unknown

From: Barendregt, Anton AA SIEP-EPF-DIR
Sent: 03 January 2004 12:29
To: Coopman, Frank F SIEP-EPF
Cc: Pay, John JR SIEP-EPS-P; Darley, John J SIEP-EPT; Bell, John J SIEP-EPS
Subject: RE: internal control weaknesses

Frank,

I have added my suggestions to your text. As a further remark: are we sure we addressed some of the shortcomings already in 2002? As far as I can see, all of the corrective action was in (late) 2003.

I have added a reference to the internal guidelines. These were, after all, the 'bible' against which I had to carry out my audits in the OUs. On the few occasions in my early years where I signalled a conflict with SEC rules I was called back by Remco and by the OUs who argued, rightly, that the only rules they should be bound by were the Group guidelines. These are the backbone of our internal controls on reserves. The spear-point of the SEC reserves auditor's control should therefore have been on a correct formulation of the Group guidelines. With hindsight, I should have been more forceful in this respect. It would have been a clear break with all my predecessors and it would probably have cost me my job in those days, but I should have. My successors will have the same constraints, only to be made easier once our uidelines are fully compliant.

I realise that Curtis may not like my reference to the guidelines. I seem to remember him saying that we should not say externally that our internal guidelines were different from the SEC's. I do not see how we can maintain that pose in ernest. It would imply saying that either our guidelines were SEC compliant (which would be an easily refutable lie) or that we had no guidelines at all, which would be unbelievable and also clearly not true.

Glad to have a further debate about this, if desired.

nton

-----Original Message-----
From: Coopman, Frank F SIEP-EPF
Sent: 02 January 2004 16:23
To: Frasier, Curtis R SI-LSEP
Cc: Darley, John J SIEP-EPT
Subject: internal control weaknesses

Curtis,

Suggested text for the Note to CMD" , paragraph 3.2 Potential issues.

Control weaknesses.

With the benefit of hindsight it is obvious where there have been control weaknesses;

At local level ;
appliance of basic disciplines in proved reserves calculations were allowed to slip. Supervisory (Chief PE) controls must have been weak.
[Barendregt, Anton AA SIEP-EPB-GRA] Due to resource constraints, compliance checking by the Group reserves auditor was typically once in every four years which allowed slackness in local controls to go undetected for quite some time.

At central EP level ;
reliance on the year end Group reserves auditors report , which would only cover the areas audited during that year.
An "independent" Group reserves auditor ***[Barendregt, Anton AA SIEP-EPB-GRA]*** whose assessments were bound by the internal reserves guidelines and who was therefore not completely independent.
no comprehensive review of all the exposed areas at set interval.

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At Group Level;
No assurance was demanded for proved reserves figures, yet the 20F requires certification.

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Barendregt
#31 2/22/07

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These control weaknesses were addressed during 2002 ***[Barendregt, Anton AA SIEP-EPB-GRA]*** ?? and 2003. The recruitment of several (instead of one) reserves auditors ,set in train, will address the resource issue. The change in reporting line will be implemented in 2004 to ensure the "independence". The 2004 assurance letter will be amended to include proved reserves.

end of text

I will ask John Pay and Anton Barendregt for comments.

Frank Coopman
Chief Financial Officer for EP
Shell International Exploration and Production B.V.
PO Box 60, 2280 AB Rijswijk ZH, The Netherlands

Tel: +31 70 447 4303 **Fax:** +31 70 447 5959
Email: Frank.Coopman@shell.com
Internet: http://www.shell.com/eandp-en

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Treatment Requested

From: Barendregt, Anton AA SIEP-EPF-DIR
To: Coopman, Frank F SIEP-EPF; Pay, John JR SIEP-EPS-P
CC:
BCC:
Sent Date: 2004-01-16 15:22:56.000
Received Date: 2004-01-16 15:22:59.000
Subject: Rockford - a historical prespective
Attachments: Rockford-HistPersp.doc

Frank, John,

Having had some time to think in the last few days I have written down my thoughts on why we ended up where we did.

I'm still not 100% happy with the text (it needs further honing), but it's in a state where I'm happy to take comments.

I'm not sure yet whether this should be part of (or an appendix to) my end-year report. At the least it is a 'witness statement' for when I've left.

Anton

Anton A. Barendregt
Shell Group Reserves Auditor
Shell International Exploration and Production B.V.
Kessler Park 1, 2288 GS RIJSWIJK-ZH, The Netherlands

Tel: +3170 447 2351 Fax: +3170 447 5950 Other Tel: (+31 70 3229452 home; +31 610 97 2351 mob)
Email: Anton.Barendregt@shell.com
Internet: http://www.shell.com/eandp-en

DEPOSITION EXHIBIT 2a
Barendregt
#32 2/22/07

PROJECT ROCKFORD - A HISTORICAL PERSPECTIVE

By A.A. Barendregt, Group Reserves Auditor

January 2004

Introduction

The impact of Project Rockford and the ensuing de-booking of 20% of the Group's proved reserves will lead to numerous questions as to why and how such an event could have arisen. This note attempts to inventorise the facts as seen from the perspective of someone who has been involved in reservoir engineering and reserves reporting since 1975 and who has been present at or closely involved in critical stages of the process of preparing and maintaining the Group reserves guidelines from the early 1990's onwards. The note aims to be objective and it does not seek to lay blaim to specific parties.

The note follows the successive historical events, as graphically presented in Fig. 2.

References to documented evidence are given where possible.

1972-2003: Group awareness of SEC rules

In 1972, the Group introduced a new method of reserves characterisation that was at that time unique in the industry (Ref. 1). The method was based on probabilistic assessment of in-place and recoverable hydrocarbon volumes, using probability density functions for each of the constituent volumetric and recovery parameters. The result would be a probability density function (or 'Expectation Curve') for recoverable reserves in each reservoir, describing the probability that reserves would exceed each of a range of values, starting with the 100% confidence (or minimum) value and ending with the 0% confidence (or maximum) value. 'Proved' reserves were postulated to be the value at which there was at least 85% confidence that reserves would be equal or larger than that value. The value was referred to as the Low or P85 estimate.

Industry practice at the time was based on the notions of 'proved', 'probable' and 'possible' reserves. 'Proved' was largely defined to mean 'more likely than not to be present', 'probable' meant 'equally likely to be present or not' and 'possible' would be 'less likely to be present than not'.

In 1978, the SEC issued specific definitions on proved reserves (Ref. 8) and requested that companies disclose these in their filings with the SEC. The definitions focused almost exclusively on the subsurface uncertainties regarding in-place and recoverable volumes. For more details see Table 1 and the Guidelines section below.

The Group (outside the US) adopted the SEC reporting requirement through the introduction of various reserves guidelines in the following years (Refs 2, 3, 4). These guidelines acknowledged (and even included copies of) the SEC guidelines, but in all cases they concluded that the Shell P85 probabilistic estimate was considered to be 'reasonably certain' and hence in compliance with the SEC definitions (Ref. 2, 3). One document (Ref. 4) stated that "Shell definitions are more rigorous [than SEC definitions]", and that the Group guidelines "generate reserves which are equivalent to those which would have been derived using the SEC definitions".

The confidence that the Group guidelines for proved reserves were compliant with SEC rules was maintained throughout the following series of guidelines (Refs 5, 6). Statements made were "The Shell Group definitions are in full compliance with [SEC] definitions and, in some instances, quantified in greater detail" (Ref. 5) and "Where Group guidelines interpret SEC definitions [...] these interpretations have been accepted by external auditors as fulfilling SEC requirements" (Ref. 6, 1996-2001)". From 1993 onwards, Group guidelines contained detailed lists of the SEC definitions and the Group's interpretations thereof. In some cases, these interpretations departed from the SEC text, e.g. by allowing probabilistic estimates of volumes below lowest known hydrocarbon (LKH) levels, by allowing PSC reserves based on Group PSV prices instead of end-year prices and by waiving the need for a pilot before booking of water injection reserves in certain cases (see Guidelines section below). This departure did not affect the confidence that Group proved reserves did fulfil SEC requirements.

The confidence in SEC compliance had two important consequences in the Group's petroleum engineering community:

- Group proved reserves guidelines became the only norm for evaluating proved reserves, also in proved reserves audits by the Group Reserves Auditor (see e.g. audit TORs in Refs.6),
- Education and awareness of SEC rules and their importance became neglected.

1996-2001: A strong drive to boost proved reserves

In the mid-1990s there was considerable internal and external pressure to boost proved reserves (Ref. 7). In particular it was found that Exxon booked higher proved reserves for their share of the (by now mature) fields in the North Sea. A LEAP value creation team was set up and this gave the recommendation that proved developed reserves should be made equal to expectation reserves. These recommendations were included into the 1998 Group guidelines, together with the recommendation that total proved reserves (i.e. developed plus undeveloped) should approach expectation reserves with increasing field production maturity. This recommendation was duly implemented and led to the booking of some additional 1000 MMbl Group share proved reserves over the period 1998-2000.

This major change in proved reserves reporting procedures was justified by the reporting practice in the industry, which was indeed less conservative than the probabilistic Group approach as far as it related to fields in mature production. However the change ignored the fact that SEC definitions tended to be more conservative than Group proved reserves for non-mature fields and reservoirs. The reasons were the rather strict SEC constraints to the 'proved area', which were interpreted more liberally by the Group's probabilistic approach. Guidelines at the time (e.g. Ref. 6, 1998) only mentioned that 'a reconciliation should be made' between proved area and the probabilistic reserves estimate, without specifying how this should be achieved.

The result was that, whilst there was a balance between over-reporting for immature fields and under-reporting for mature fields, this balance was effectively removed in 1998, see the schematic picture below. What remained was a potential overstatement of reserves on the immature end of the project spectrum. This was not sufficiently recognised at the time.

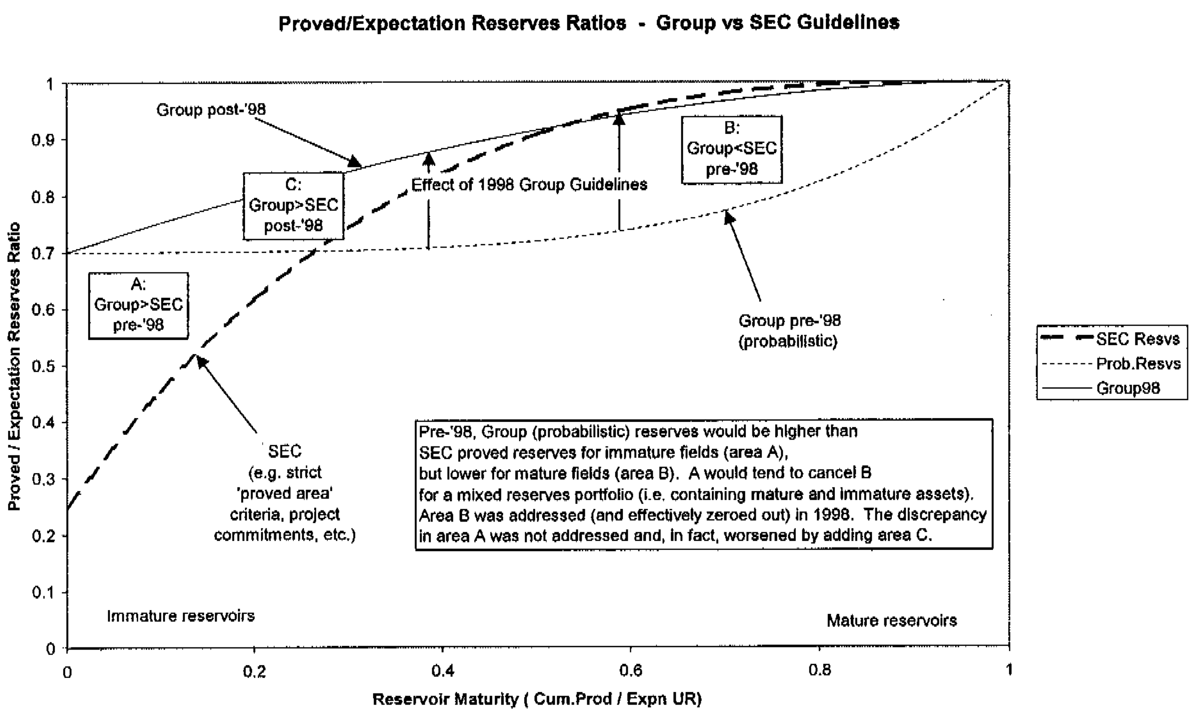

Figure 1 – Proved / Expectation reserves ratios – Group vs. SEC guidelines

1996-2001: Other aggressive reserves bookings

As mentioned, the new 1998 guidelines resulted in a significant volume of new reserves bookings in mature fields in most of the large OUs. Most of the OUs reported these additions in 1998, some in 1999. One of the OUs seen to be lagging behind was PDO. During a 1999 reserves audit it was noted that individual field proved reserves were too low in comparison with expectation reserves as many of these were still based on pre-development probabilistic estimates. Guidelines were left on how to build a proved reserves forecast portfolio with which to make a proper assessment of reserves producible within the duration of the production licence in 2012. However, by end 2000 no progress had been made in this respect. Following a visit by the SIEP

Reserves Coordinator, PDO were advised to amend their corporate proved reserves estimate, based on a continuation of the then current plateau of 850 Mb/d until 2008, followed by a relatively steep decline thereafter. This assumption of a continued plateau production was based on PDO's Business Plan, which foresaw a continuation of the 850 kb/d plateau at least until 2010. The implied lifetime proved reserves were some 75% of lifetime expectation reserves, which was not unreasonable. The implied assumption was also that PDO's drilling and development sequence would be accelerated if field reserves were to materialise at proved and not at expectation levels.

With hindsight, this advice has been unfortunate, not least because PDO's production levels declined sharply in the following years, implying that expectation forecasts were grossly optimistic. More fundamentally, the advice induced PDO to relinquish the audit trail to individual field proved reserves estimates. The understanding was that PDO would re-establish this link in 2001 by proper individual field proved forecasting, but this never happened. This regrettable situation was perpetuated and in fact worsened in 2001 and 2002 when PDO chose not to reduce proved reserves even when it was clear that stated proved reserves could not be produced before end-of-licence with the lower production levels.

SPDC had been booking significant increases in proved reserves since 1996, with major leaps in 1998 and 1999 following the implementation of new guidelines with respect to mature fields. The sum of the 1998 and 1999 reserves additions (Group share) was some 1000 MMbl of oil+NGL, of which some 460 MMbl was attributed to the new guidelines. The remainder was the result of field reviews, correction of negative reserves etc. A reserves audit in 1999 did not find any significant areas of non-compliance with Group guidelines, which at that time were not very strict on project definition and maturity (see below).

At end 1998, the proved reserves over annual production ratio (R/P) was 32 years. With 20.5 years still to go to the end of licence in 2019, this implied that the relatively steep production increase planned in those years would indeed be required in order to produce all of the stated proved reserves before end-of-licence. In subsequent years it became clear that, due to funding constraints, associated gas gathering delays ('flares out by 2008'!) and community disturbances it would be unlikely that the aspired production level increases would be realised. At end 2002 the R/P ratio stood still at 32 years, while the number of years to end-of-licence had shrunk to 16.5 years. This should have led SPDC to reduce their booked proved reserves accordingly, but it was decided to impose only a 'moratorium' (i.e. a freeze) on liquids reserves instead.

In the course of 2002 SPDC discovered that Nigerian law does in fact provide a right for production licence holders to have these licences extended upon expiry (subject to fulfilment of all licence obligations). SEC stipulations require an established 'track record' of the granting of such extensions and this is available in the Nigerian environment. These circumstances removed the potentially serious overstatement of proved reserves on licence duration grounds. However, by that time SEC had published the requirement for project maturity and commitment (see below) and this changed, but did not reduce the focus on SPDC reserves exposures. Many of the reserves increases booked on the late 1990s by SPDC had been based on reservoir reviews and long term development plans which were acceptable as a basis for proved reserves under previous Group guidelines but which could not pass the test of actual project commitment.

Significant proved reserves additions were also booked in other areas during the late 1990s. Many of these related to first-time bookings for new fields, some of them in frontier areas. Two important examples are the large Gorgon gas field offshore the Australian Northwest shelf and the more recently discovered Ormen Lange gas field in the Norwegian North Sea. The first field requires a major new opening in the Pacific Rim gas market, which seemed imminent at the time of booking, but which has been delayed significantly following the downturns in the Asian and worldwide economies in the late 1990s and in 2002. The Ormen Lange field faced a major technical challenge in perceived sea bottom stability, which has taken significant work to be relegated back to the 'negligible risk' category. FID on Ormen Lange will be taken shortly. Both proved reserves bookings were in accordance with Group reserves guidelines at the time.

Other proved reserves bookings on new field developments were made in Brunei, Venezuela, Nigeria (SNEPCO), New Zealand, the Netherlands and Norway (see Table 2). All of these were based on proper field development plans formulated at the time, which made them in accordance with Group guidelines. However, actual development was only foreseen in the longer term, either because of economic competition by other developments or, as in the case of the Waddenzee volumes in the Netherlands, because of a government moratorium on drilling.

Two undeveloped fields with apparently premature proved reserves were added to the portfolio in 2002 as part of the Enterprise Oil acquisition. One was in Italy (Tempa Rossa) where various licence and commercial uncertainties made the associated proved reserves exposed. The other was offshore Ireland (Corrib) where project development had already started but where an appeal had been lodged against the planning permission for the onshore gas processing plant. Both of these reserves bookings had already been made by Enterprise. Progress on the Tempa Rossa development has been disappointing during 2003 and the appeal against the planning permission in Ireland was sustained during 2003, making another application for planning permission necessary.

With the exception of the ex-Enterprise assets, most of the reserves additions discussed above appear to have been made in accordance with Group reserves guidelines prevailing at the time. They became only non-compliant when the guidelines were tightened in 2002-2003. The exceptions were the proved reserves moratoria in SPDC and PDO in 2001 and 2002, which, although not expressly forbidden by the guidelines, did go beyond the 'reasonable certainty' required of them. Production constraint criteria for licence-constrained operations were not introduced until 2002.

Reserves targets in Group score cards

Another consequence of the drive towards boosting proved reserves in the late 1990s was the introduction of proved reserves addition targets in scorecards for variable pay, both for individuals and for groups. This led to some aggressive attempts at booking of proved reserves at the immature end of the Group reserves spectrum. The prevailing mood at the time is best reflected by the often-posed question: "Tell me where it says in your guidelines that I can't do this". The consequent discussions about the appropriateness of such bookings led to immense pressure on e.g. reserves coordination staff in SIEP and on anyone suggesting a more moderate approach.

The SEC have not issued guidance on the appropriateness of individuals' pay being influenced by the amount of proved reserves booked by them. The SPE have issued such guidance and they clearly condemn such influence as unacceptable (Ref. 12). Concern was expressed about the proved reserves addition targets in a succession of Group Reserves Auditor reports identifying these as potential integrity threats to the Group's proved reserves filings (Ref. 11, 2000-2002), but the targets are still in effect.

The proponents of proved reserves addition targets will maintain that the controls in place (e.g. guidelines, reserves audits, end-year submission reviews and now end-year challenge sessions) should prevent inappropriate reserves being booked. However, these controls can only be effective if control resource levels are adequate. This has not been the case. Examples are the wholly inappropriate moratoria on proved reserves introduced by PDO and SPDC in 2001, which could have been detected by a higher frequency in reserves audits (see below). The more fundamental objection against the setting of reserves addition targets, i.e. that it affects the objectivity of the reserves estimator, stands unchallenged.

SEC definitions and Group Reserves Guidelines

Until 2001, there were only a few relatively small differences between the 1978 SEC reserves definitions and the Group proved reserves guidelines (see Table 2). The most significant difference in this period was the oil price assumption for PSCs and similar contracts, which the SEC required to be at end-year price levels and which Group guidelines set at mid-PSV levels. Because the latter were set conservatively, this implied an overstatement of Group PSC proved reserves, which has been maintained until 2003.

It is important to note that the SEC rules of 1978 made <u>no</u> reference to the (un)certainty that undeveloped reserves would actually become developed. The only general reference was to 'reasonable certainty' (see Table 1). The Group guidelines were, if anything, more specific about the issue. Since 1993 there was a requirement in the Group guidelines that undeveloped reserves should be based on identified projects, with associated well targets, costs and economics. However, these projects could be notional or simply based on analogies with similar fields or reservoirs.

During the period pre-2001, most US based companies seem to have settled on a practice whereby proved reserves would generally only be booked when projects were close to being committed. The explanation for this could be that, once evaluated and quantified (making reserves bookable), a property would be developed quickly because there were very few physical or bureaucratic hindrances standing in the way. Development costs also tended to be low initially and risks were small. SOC (later SEPCo) adopted this self-imposed practice (of waiting for full FDP or even FID) in 1986, following some embarrassment from a series of negative reserves revisions.

In 2001, following pre-announcement during the preceding year, the SEC published 'guidance' on their website, giving clarification about how they wished to see the original 1978 reserves definitions interpreted by the industry (Ref. 9). The most significant new item in the 2001 guidance was that the SEC wished to see a 'commitment' to those projects for which proved undeveloped reserves had been booked. This 'commitment' requirement was largely in line with reserves booking practice in the US. It was also seen as sensible and desirable, providing a clear criterion against which to assess the appropriateness of booking proved reserves. However, it presented an immediate threat to the SEC compliance of an (at that time unknown) volume of

Group proved reserves, because these had been booked under Group guidelines that were less strict, allowing e.g. notional projects as a basis.

In reaction to the new SEC guidance, the Group guidelines were changed gradually to the point where, at end 2003, they required either FID, a VAR3 or a full FDP for large, medium and small projects respectively before proved reserves could be booked (Ref. 6, 2003). These changes were introduced partly at the recommendation of end-year reserves auditor reports and also to prevent premature reserves bookings for new projects.

The 2001 SEC guidance was followed by an exchange of letters between the Group and the SEC during 2002 and 2003, in which the SEC expressed an even stricter interpretation regarding the LKH issue.

The remaining areas of divergence between the recent SEC guidance and the 2003 Group guidelines are thus the strict definition of the 'proved area' (producibility, LKH and continuity of production) and the price assumptions for PSCs (see Table 1). A stricter requirement for adherence to the 'proved area' concept had already been introduced in the Group guidelines in 2001. The divergence on the need for an improved recovery pilot is not material in the Group's portfolio, with only some exposure in Sakhalin, which will be addressed per end 2003. The FDP/VAR3/FID criterion may not be completely congruent with the SEC 'commitment' requirement, but it can be argued that, if there is a track record of the company to carry out its planned (FDP'd or VAR3'd) projects this can be seen as sufficient commitment.

In summary, the most significant change in the SEC definitions and guidance in 2001 was the introduction of the need for project commitment before proved reserves could be booked. This resulted in an immediate threat of non-compliance to a large (but unknown) volumes of the Group's proved reserves. Group guidelines have largely been brought in agreement with SEC guidance in 2002. Remaining, lesser discrepancies, will be removed in 2004.

Reasons for non-compliance

The new 2003 Group guidelines were applied in two proved reserves audits late in 2003, one in SPDC and one in PDO. Both companies had been challenged in the end-2002 reserves audit report regarding their continued moratorium on proved reserves when it was clear that stagnant production (in SPDC) or indeed production declines (in PDO) made their booked proved reserves questionable. Both companies had started extensive internal reviews to investigate the status of reservoir knowledge and the maturity of their project portfolios forming the basis for undeveloped reserves. When the potential magnitude of exposure in both companies became clear, a thorough scan was made through the Group-wide Business Plan portfolio to identify other areas with volumes that were based on longer term projects for which no VAR3 / FID had been taken yet. This resulted in the list of Table 2.

From this list it can be seen that the requirement of project commitment formed by far the largest reason for compliance failure in the list of exposed proved volumes.

The conclusion is therefore that it was the 2001 insistence on project commitment by the SEC that caused the compliance failure of the large majority of the reserves to be de-booked per end 2003. As demonstrated by Table 1, these reserves were in compliance with both Group and SEC guidelines before 2001, because the guidelines were either not very strict or non-existent on this issue.

Group Reserves Audits

Group reserves guidelines were the only technical control document distributed throughout the Group on the issue of estimating and booking proved reserves. Hence, these were also the only reference against which proved reserves audits in the OUs and at end-year in SIEP could be (and should have been) carried out.

The historically set frequency of OU reserves audits had been once every four years, or more frequently if indicated by e.g. unsatisfactory audit results. The experience, particularly in the last few years, has been that this frequency has been too low. Repeat audits in various OUs have shown that an OU's reserves reporting procedures can deteriorate quite quickly upon critical staff re-assignments or re-organisations. A more intensive programme of OU audits (at least once every two years) has now been agreed as desirable and this is being implemented. Such a higher frequency could have detected the inappropriateness of e.g. the SPDC and PDO proved reserves moratoria in a much earlier stage.

As the potential conflicts between SEC definitions and guidance and Group reserves guidelines became clearer, these were generally flagged in audit reports. Group reserves guidelines were then gradually adapted to ensure closer alignment with SEC requirements where possible and when deemed appropriate.

Other follow-up from the reserves audits included the setting up by SIEP of an 'Exposure Register' of volumes that were potentially non-compliant with either Group or SEC requirements. The total volume in this register was deemed to be less than material in relation to the total Group portfolio and any associated de-bookings were held pending until more data, positive or negative, would become available.

Conclusions

In summary, it is the writer's opinion that the following factors have played a role in the build-up towards project Rockford:

- The inappropriate notion that Group reserves guidelines were in full compliance with SEC definitions, perpetuated in the series of Group reserves guidelines since 1980
- The lack of awareness of the significance of SEC reporting requirements among the Group's petroleum engineering community,
- The significant drive for proved reserves additions in mature fields in the late 1990s, without paying heed to the requirements for constraining proved reserves in immature fields,
- The introduction of proved reserves addition targets in individuals' scorecards, which removed much of the objectivity required in proved reserves evaluations, and which prevented reserves de-bookings when these would have been appropriate,
- The historical lack of perception within the Group of the need for some form of project commitment before proved reserves should be booked, which left the Group vulnerable to new SEC guidance in 2001.

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Subject	1978 SEC Definition	Group guidelines pre-2001	2001-2003 SEC Guidance	Group guidelines end-2003
Reservoir 'Proved Area':				
Producibility	Producibility proven by production test or log and core based analogue	Producibility proven by production test or log or core based analogue	Producibility proven by production test or log and core based analogue	Producibility proven by production test or log or core based analogue
LKH	If no information on fluid levels: no proved reserves below LKH	Proved reserves below LKH if indicated by pressures or seismic amplitude mapping, or included in probabilistic estimate	No proved reserves below LKH under any circumstances	Proved reserves below LKH if indicated by pressures or seismic amplitude mapping
'Continuity of production'	Continuity of production must be certain (max. 9 well spacings around existing wells)	'Continuity of production' uncertainty included in probabilistic or multi-scenario estimate	Continuity of production must be certain (max. 9 well spacings around existing wells)	'Continuity of production' uncertainty included in probabilistic or multi-scenario estimate
'Improved Recovery'	Successful (pilot) test required, either in the reservoir itself or in the same reservoir in a different field in the area	Successful pilot test required unless the project can go ahead without it ('Value of Information' approach)	Successful (pilot) test required, either in the reservoir itself or in the same reservoir in a different field in the area	Successful pilot test required unless the project can go ahead without it ('Value of Information' approach)
'Existing Conditions'	Existing (year-end) prices and cost estimate assumptions required for confirming economic viability	Mid PSV prices and cost assumptions, also for PSCs	Existing (year-end) prices and cost estimate assumptions required for confirming economic viability	Mid PSV prices and cost assumptions, also for PSCs
'Reasonable Certainty'	'No 'reasonable doubt' about geology, reservoir or economic factors	Proved undeveloped reserves must be based on an identified project, which may be notional	Proved undeveloped reserves must have a commitment to the project	Proved undeveloped reserves must have an FDP / VAR3 / FID for small / medium / large projects

Table 1 - Main elements and differences of successive proved reserves definitions