StatoilHydro ASA

US Securities and Exchange Commission
Attn.: Secretary
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20549-1090 Washington DC
USA

17 CFR Parts 210, 229, and 249 [Release Nos. 33–8935; 34–58030; File No.S7–15–08]

Modernization of the Oil and Gas Reporting Requirements

Principal comments

StatoilHydro would first of all like to thank the Commission for taking these bold steps to improve oil and gas reporting requirements and for the opportunity to take part in this initiative through the comments process. StatoilHydro is of the opinion that in general, the proposed rules will result in a more meaningful and comprehensive understanding of filers' oil and gas reserves.

With due respect for the great advances proposed by the SEC, StatoilHydro would like to point out some key areas that we feel warrant further attention:

- In its constructive efforts to help investors evaluate the relative value of oil and gas companies, greater attention should be paid to the direct indicators of value. In particular, further attention should be paid to the reporting of the legal rights related to oil and gas production, whether embedded in concessions, production sharing agreements, service and other agreements joint ventures or affiliated (equity accounted) companies. By the same token, operational and other information that is weakly correlated to value should be scrutinised for potential deletion from the reporting requirement, not necessarily preventing filers from disclosing such information as part of their regular information about their activities. A move to more direct indicators of value will make it less necessary to increase the granularity of reporting to a point where users gain insight into specific projects or areas, threatening the destruction of commercial values.

- In moving toward global standards, the SEC is commended for leaning on classifications that hold potential for being building blocks for global standards, not only in financial reporting, but also in other areas such as business process management and government resource management. We recommend that this line be continued and strengthened in the work leading to final rules, looking closely at the UN efforts in uniting the initiatives which are widely recognised across the extractive industry as well as among foreign governments, regulators and filers. Global multi-purpose terminology for extractive activities will provide clarity and efficiencies for preparers and users.

- We recommend the use of future prices. Ideally they represent risk discounted price forecasts. In the past they have however been reflective of current prices as shown on the enclosed graph. The move from year-end prices should therefore not be dramatic. StatoilHydro agrees with the

Commission that the applications of price in the proposed rules makes it appropriate to look to the future and not to the past. In addition to being relevant with respect to direction, we expect them also to be less affected by short term volatility caused by well understood and short lived supply disruptions or demand swings. We also agree that the future prices may not always be available for all qualities and locations, but this also applies to year end prices. A mixed procedure of using relevant futures prices and observed differentials would reflect current practise and should be acceptable. As in other areas of accounting, sound judgement will be required, but not beyond the ordinary. We strongly object to a scheme where two different prices are used for accounting and reserves reporting purposes. Historical prices cannot be applied to all areas of accounting. This further supports our view to use future prices.

- StatoilHydro appreciates the efforts put into the convergence between US and international accounting standards, and praises the Commission for its involvement in this process. To the extent possible, the revised oil and gas reporting requirements should be as closely aligned with the overall objective of international conversion as possible.

- StatoilHydro recognises the importance of discussing the use of external experts, but submits that a functional requirement to maintain and report on the quality of internal controls surrounding the reserves (and value) estimation process is more important and easier to implement than prescribing in details how to report on the use of external parties.

Please see the enclosed document for detailed replies to the questions raised by the Commission.

StatoilHydro is prepared to discuss the replies in further details upon request.

Kind regards
StatoilHydro ASA

/s/ Eldar Sætre
CFO

Enclosed: Detailed responses

SECURITIES AND EXCHANGE COMMISSION

17 CFR Parts 210, 229, and 249 [Release Nos. 33–8935; 34–58030; File No.S7–15–08]

Modernization of the Oil and Gas Reporting Requirements

Response to proposed rules

App A Revisions and Additions to the Definition Section in Rule 4–10 of Regulation S–X

A.1 B. Year-End Pricing

A.1.1 12-Month Average Price

. Should the economic producibility of a company's oil and gas reserves be based on a 12-month historical average price? Should we consider an historical average price over a shorter period of time, such as three, six, or nine months?

Should we consider a longer period of time, such as two years? If so, why?

The starting point should be that the filers use the most relevant information about future prices. Forward prices are available for several years into the future and for various qualities of crude oil. Unfortunately, such forward prices are not available for all crude oil qualities, nor natural gas liquids or dry gas. To the extent forward prices are available for a crude oil quality or natural gas reserve in question, forward prices may not be relevant due to geographic location of the resources in question. Year-end prices, on the other hand, are typically more readily available, and can, if necessary be adjusted for quality and location differentials based on recent transactions. The adjustment for quality and geographical spreads is of course a matter of judgement and not an exact science, but so is much else in the reserves estimation process.

Furthermore, as illustrated in the attached graph, spot prices represent a reasonably good estimate of forward prices, but with the reduced short term volatility that the Commission seeks.

StatoilHydro is therefore of the opinion that oil and gas reserves should not be based on a 12-month historical average price.

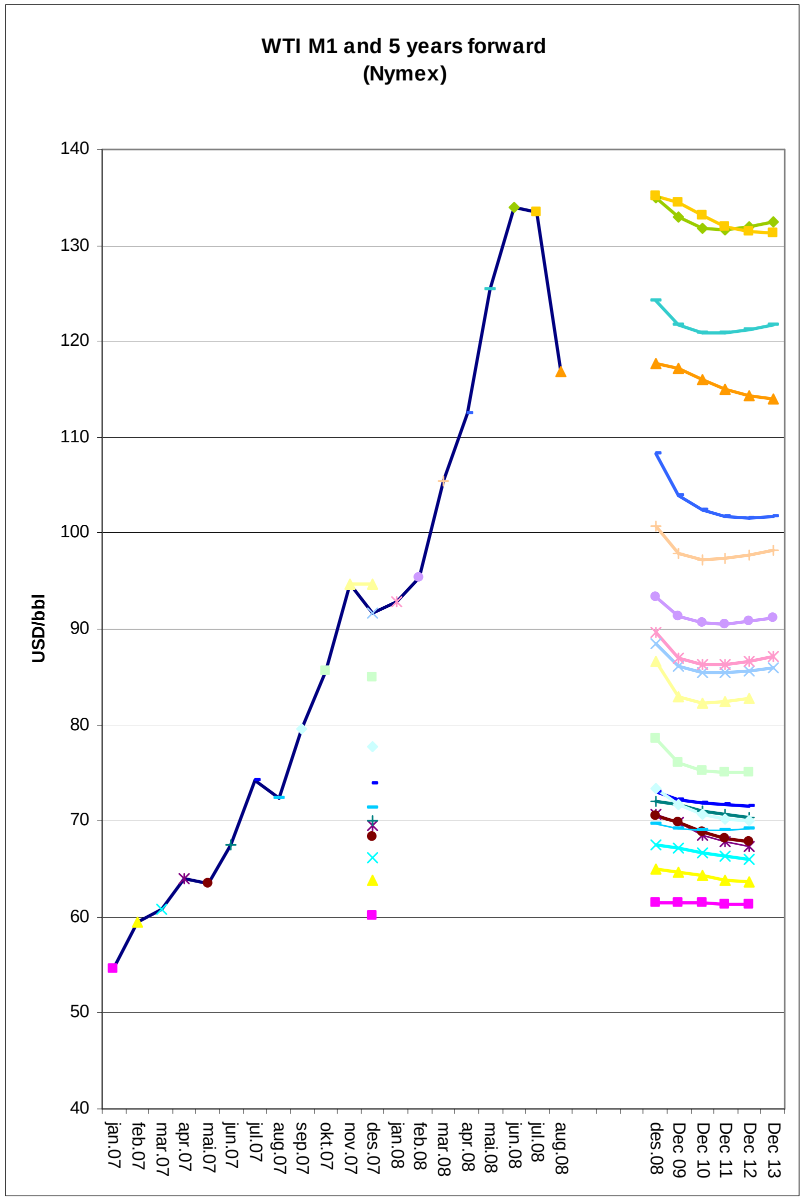
. Should we require a different pricing method? Should we require the use of futures prices instead of historical prices? Is here enough information on futures prices and appropriate differentials for all products in all geographic areas to provide sufficient reporting consistency and comparability?

. Should the average price be calculated based on the prices on the last day of each month during the 12- month period, as proposed? Is there another method to calculate the price that would be more representative of the 12-month average, such as prices on the first day of each month? Why would such a method be preferable?

. Should we require, rather than merely permit, disclosure based on several different pricing methods? If so, which different methods should we require?

. Should we require a different price, or supplemental disclosure, if circumstances indicate a consistent trend in prices, such as if prices at yearend are materially above or below the average price for that year? If so, should we specify the particular circumstances that would trigger such disclosure, such as a 10%, 20%, or 30% differential between the average price and the yearend price? If so, what circumstances should we specify?

The starting point should be that the filers use the most relevant information about future prices. Forward prices are available for several years into the future and for various qualities of crude oil. Unfortunately, such forward prices are not available for all crude oil qualities, nor natural gas liquids or dry gas. To the extent forward prices are available for a crude oil quality or natural gas reserve in question, forward prices may not be relevant due to geographic location of the resources in question. Year-end prices, on the other hand, are typically more readily available, and can, if necessary be adjusted for quality and location differentials based on recent transactions.



The adjustment for quality and geographical spreads is of course a matter of judgement and not an exact science, but so it much else in the reserves estimation process and most other aspects of financial reporting. The use of a directly observable quality differential over time does not add significant quality to the estimate, and if so, only objectivity. Financial reporting is increasingly focused on providing forward looking information since it is more relevant to the users. This should be the case with reserves estimates too.

Furthermore, as illustrated in graph below, forward prices for the next five years (Forward curves are the coloured lines to the right, each corresponding to a spot price in the curve to the left) are normally fairly flat compared to spot prices. As such, spot prices represent a reasonably good estimate of forward prices. Although not a perfect substitute, one can argue that the quality adjusted spot price at year-end represents a reasonable alternative to forward prices. This alternative also has the benefit of reducing the degree of management judgement about future prices beyond the observable forward curves.

The use of historical prices on the other hand has the merit of being objectively observable. Unfortunately, such data is also irrelevant. The graph can again serve to illustrate the point; hardly any average of any period can represent what an active market predicts about future prices.

StatoilHydro strongly recommends the use of relevant prices, even if tainted by some degrees of uncertainty, and opposes the use of historical prices, even if such prices are directly observable and objective.

StatoilHydro is therefore of the opinion that oil and gas reserves should not be based on a 12-month historical average price.

A.1.2 Trailing Year-End

. Should the price used to determine the economic producibility of oil and gas reserves be based on a time period other than the fiscal year, as some commenters have suggested? If so, how would such pricing be useful? Would the use of a pricing period other than the fiscal year be misleading to investors?

. Is a lag time between the close of the pricing period and the end of the company's fiscal year necessary? If so, should the pricing period close one month, two months, three months, or more before the end of the fiscal year? Explain why a particular lag time is preferable or necessary. Do accelerated filing deadlines for the periodic reports of larger companies justify using a pricing period ending before the fiscal year end?

A lag time between the close of the pricing period and the end of the fiscal year will leave time to improve the precision of the estimates. It will however make them less relevant. StatoilHydro does not support a lag time. We believe that the process which must take place after the close of the fiscal year may include corrections for the difference between the price assumptions used to prepare the report earlier in the year and the observed prices, and that the requirement for relevance, under these circumstances, takes precedence over the requirement for perceived precision.

A.1.3 Prices Used for Accounting Purposes

Proved reserves should only be one number, not two based on different price assumptions. StatoilHydro thinks that one should only use one set of price assumptions; preferably forward prices or adjusted for relevant quality and location differentials.

. Should we require companies to use the same prices for accounting purposes as for disclosure outside of the financial statements?

Yes. To the extent we have to report on proved reserves, it should only be one number for all reporting purposes, not two based on different price assumptions. StatoilHydro is of the opinion that one should only use one set of price assumptions; preferably forward prices or at least year-end prices adjusted for relevant quality and location differentials.

. Is there a basis to continue to treat companies using the full cost accounting method differently from companies using the successful efforts accounting method? For example, should we require, or allow, a company using the successful efforts accounting method to use an average price but require companies using the full cost accounting method to use a single-day,

All filers should use forward prices, or year-end prices as a substitute for forward prices.

. Should we require companies using the full cost accounting method to use a single-day, year-end price to calculate the limitation on capitalized costs under that accounting method, as proposed? If such a company were to use an average price and prices are higher than the average at year end or at the time the company issues its financial statements, should that company be required to record an impairment charge?

No comment.

. Should the disclosures required by SFAS 69 be prepared based on different prices than the disclosures required by proposed Section 1200?

No.

. If proved reserves, for purposes of disclosure outside of the financial statements, other than supplemental information provided pursuant to SFAS 69, are defined differently from reserves for purposes of determining depreciation, should we require disclosure of that fact, including quantification of the difference, if the effect on depreciation is material?

If material, yes.

. What concerns would be raised by rules that require the use of different prices for accounting and disclosure purposes? For example, is it consistent to use an average price to estimate the amount of reserves, but then apply a single-day price to calculate the ceiling test under the full cost accounting method? Would companies have sufficient time to prepare separate

reserves estimates for purposes of reserves disclosure on one hand, and calculation of depreciation on the other? Would such a requirement impose an unnecessary burden on companies?

The use of different prices leaves an inconsistency in the definition of proved reserves, will add confusion within financial reports and represents a significant administrative burden, while it does not add any value to the financial report.

. Will our proposed change to the definitions of proved reserves and proved developed reserves for accounting purposes have an impact on current depreciation amounts or net income and to what degree?

Everything else equal, the proposed changes to the definitions will lead to an increase in proved reserves and proved developed reserves. Annual production of oil and gas in proportion to proved reserves will consequently decrease, and so will depreciation. The effects will vary between fields, and will likely be least significant for mature fields. The overall effect for the portfolio has not been estimated, but is expected to slightly increase operating income.

. If we change the definitions of proved reserves and proved developed reserves to use average pricing for accounting purposes, what would be the impact of that change on current depreciation amounts and on the ceiling test? Would the differences be significant?

No basis for comment.

A.2 C. Extraction of Bitumen and Other Non-Traditional Resources

. Should we consider the extraction of bitumen from oil sands, extraction of synthetic oil from oil shales, and production of natural gas and synthetic oil and gas from coal beds to be considered oil and gas producing activities, as proposed?

Yes.

Are there other non-traditional resources whose extraction should be considered oil and gas producing activities? If so, why?

We recommend a functional approach based on the commodity that is sold and thus exposed to market prices and price uncertainties. If the product is oil and gas, then the projects of extracting and producing them should be included without regard to how they are produced physically.

Both the UN Framework Classification for Fossil Energy and Mineral Resources (UNFC) and the SPE PRMS have introduced the concept of a reserves reference point that the Commission has embedded in its proposed reserves definition. This facilitates the writing of a functional and commodity independent requirement.

. The extraction of coal raises issues because it is most often used directly as mined fuel, although hydrocarbons can be extracted from it. As noted above, we propose to include the extraction of coalbed methane as an oil and gas producing activity. However, the actual mining of coal has traditionally been viewed as a mining activity. In most cases, extracted coal is used as feedstock for energy production rather than refined further to extract hydrocarbons. However, as technologies progress, certain processes to extract hydrocarbons from extracted coal, such as coal gasification, may become more prevalent. Applying rules to coal based on the ultimate use of the resource could lead to different disclosure and accounting implications for similar coal mining companies based solely on the coal's end use. How should we address these concerns? Should all coal extraction be considered an oil and gas producing activity? Should it all be considered mining activity? Should the treatment be based on the end use of the coal? Please provide a detailed explanation for your comments.

Once the Commission defines the commodity at the reserves reference point this issue is resolved. If the quantities crossing that point are quantities of oil and gas, the activities of producing them should be reported as oil and gas activities. If it is coal sold or delivered as raw material for further processing, the activities should be considered to be coal mining activities.

. Similar issues could arise regarding oil shales, although to a significantly less extent, because those resources currently are used as direct fuel only in limited applications. How should we treat the extraction of oil shales?

See response above

. If adopted, how would the proposed changes affect the financial statements of producers of non-traditional resources and mining producers?

They would be required to report in accordance with the rules following from this proposal.

The project status based procedure proposed is in principle commodity independent.

A.3 D. Reasonable Certainty and Proved Oil and Gas Reserves

. Is the proposed definition of ''reasonable certainty'' as ''much more likely to be achieved than not'' a clear standard? Is the standard in the proposed definition appropriate? Would a different standard be more appropriate?

. Is the proposed 90% threshold appropriate for defining reasonable certainty when probabilistic methods are used? Should we use another percentage value? If so, what value?

A 90% probability that the reported quantity will be exceeded is in line with the SPE/WPC definitions of 1997. It is repeated in the SPE/WPC/AAPG classification of 2000, the UNFC of 2004 and the SPE PRMS. It is well established and an appropriate threshold to apply. When deterministic methods are applied, the estimates should be equivalent to the ones obtained by probabilistic estimates. This defines reasonable certainty.

A.3.1 New Technology

. Is our proposed definition of ''reliable technology'' appropriate? Should we change any of its proposed criteria, such as widespread acceptance, consistency, or 90% reliability?

We propose to define ''reliable technology'' as ''technology (including <u>estimation and</u> computational methods) that, when applied using high quality geoscience and engineering data, is widely accepted within the oil and gas industry, has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation.''

By analogous formation we understand in this context a formation that has analogous properties and an analogous geological history in terms of the physical and chemical processes. Geographic proximity is not related to properties directly. Introducing this as a criterion will penalise new basins unjustifiably.

We believe that it will be very difficult to measure the reliability of technology objectively to the accuracy proposed. The requirement of 90% reliability on technology is too strict. Information of lower reliability may cross check with other information to provide greater or lesser confidence than that which can be obtained by technology of high recognised technological reliability alone.

The reliability criterion is covered by the definition of reasonable certainty. It should not be weakened by further specification.

. Is the open-ended type of definition of ''reliable technology'' that we propose appropriate? Would permitting the company to determine which technologies to use to determine their reserves estimates be subject to abuse? Do investors have the capacity to distinguish whether a particular technology is reasonable for use in a particular situation? What are the risks associated with adoption of such a definition?

See response above. While one can never guard against abuse 100%, a functional requirement with accountability as proposed will deter from such abuse. It will be a stricter requirement in the sense that it will not be possible in hindsight to defend a wrong estimate by referring to having used prescribed procedure.

We propose that disclosure of the technology used should not be required, it should be up to management to decide which volumes to include in proved, probable and possible reserves within guidelines given.

It is also difficult to point to only one type of technology used as basis for reserve estimate establishment (basis for field development plan). Normally several different technologies used for the same field. TheMoreover, the type technology used will vary from field to field. To give a full picture a large amount of detailed information must be provided, down to field level? Information on . Finally, information of technology used may be confidential and could give loss of competitive advantage.

Investors should not be required to do complete project reviews including engineering analyses, acknowledging that the information required is too extensive relative to what can be realistically communicated in the public domain.

Filers may not be free to disclose confidential information on technology, whether it is their own, or belongs to a third party.

. Is the proposed disclosure of the technology used to establish the appropriate level of certainty for material properties in a company's first filing with the Commission and for material additions to reserves estimates in subsequent filings appropriate?

Should we require disclosure of the technology used for all properties? Should we require companies currently filing reports with the Commission to disclose the technology used to establish appropriate levels of certainty regarding their currently disclosed reserves estimates?

The Commission should be silent on disclosures of technologies used. A filer will, in general, use the technologies and procedures required for a particular estimate to meet the functional requirements. Voluntary disclosures should not be prohibited.

A.3.2 Probabilistic Methods

. Are the proposed definitions of ‘‘deterministic estimate’’ and ‘‘probabilistic estimate’’ appropriate? Should we revise either of these definitions in any way? If so, how?

. Are the statements regarding the use of deterministic and probabilistic estimates in the proposed definition of ‘‘reasonable certainty’’ appropriate? Should we change them in any way? If so, how?

The proposed definition of reasonable certainty as *"much more likely to be achieved than not"* does not add materially to the meaning of the text. It is clearer as a naked text in the context of the 90% threshold required for probabilistic estimates and a requirement that deterministic and probabilistic estimates should be of comparable certainty.

The definition of probabilistic methods is appropriate provided the materiality criterion applies. It is not realistic to require that the full range of values that could reasonably occur from each unknown parameter is used to generate a full range of possible outcomes. Emphasis in a requirement of this sort should be on the range of outcomes, not on the inputs, allowing the reporter to use only the inputs that have effect on the outcomes.

. Should an oil and gas company have the choice of using deterministic or probabilistic methods for reserves estimation, or should we require one method? If we were to require a single method, which one should it be? Why? Would there be greater comparability between companies if only one method was used?

Yes, there should be a choice.

Enhanced comparability would follow from comment A3 above.

. Should we require companies to disclose whether they use deterministic or probabilistic methods for their reserves estimates?

Yes.

A.3.3 Other Revisions Related to Proved Oil and Gas Reserves

. Should we permit the use of technologies that do not provide direct information on fluid contacts to establish reservoir fluid contacts, provided that they meet the definition of ‘‘reliable technology’’ as proposed?

Yes.

. Should there be other requirements to establish that reserves are proved? For example, for a project to be reasonably certain of implementation, is it necessary for the issuer to demonstrate either that it will be able to finance the project from internal cash flow or that it has secured external financing?

The issue here is to define reserves. The project status based classification classifies the projects and then provide the uncertain quantities that the projects will produce. A line defining reserves, is drawn between justified projects and contingent projects.

Even in a case where the reporter has exclusive rights to produce the oil and gas, and a plan for development and operation is approved by the authorities and committed financially and otherwise by the reporter, there are permissions to be obtained. These may be internal in the form of approval of each well and perforation, or external in the form of consent to start operations upon completion of the development works, confirming compliance with all laws, regulations and other requirements in force.

We believe that a project should qualify for producing reserves once the exclusive rights are in place and principal approvals to implement the project (internal and if required external) have been secured. The detailed approvals should not be required unless they represent a clear and probable threat to the implementation of the project as a whole.

Some undeveloped reserves may be produced through justified but not committed projects in the case where the rights are in place and it is justified beyond doubt that the quantities may be produced, but where implementation of the project is sufficiently far into the future that project implementation in detail and in the form of specific financial commitment is not yet required and considered. This could be the late phases of gas developments where production capacity will be replaced or expanded as and when required, often depending on the performance of the initial projects. It could also be large recoverable quantities in the Middle East or elsewhere, that for obvious reasons are communicated as reserves, although strategic considerations do not call for their immediate development leading to a postponement in the planning and commitment to a physical project.

A part of this issue was discussed at the IASB Meeting on the 20th of June 2008. The SPE-PRMS addresses it in its section 2.1.2 Determination of Commerciality.

A.4 E. Unproved Reserves—''Probable Reserves'' and ''Possible Reserves''

. Should we permit a company to disclose its probable or possible reserves, as proposed? If so, why?

Yes, you should permit the reporting of proved plus probable reserves. It is exceedingly important that these recoverable quantities be disclosed. They are close to the expected values of the quantities that the projects will produce. As a result they play a much more important role in the investment decision than the other two. Their arithmetic sum is also relevant measures of the sum of quantities that a portfolio of projects will produce.

We caution against the disclosure of possible reserves. This is a useful disclosure for a single project, but not one that will meet concerns for reliability. The chance that all projects turn out better than expected is negligible for a large enough portfolio. The law of large numbers will therefore cause the arithmetic sum of high estimates to be irrelevant in the sense that they lie outside and above the reasonable range of estimates for the portfolio. To disclose the sum will therefore easily mislead the reader to believe that the quantities can become higher than what there is a reasonable basis for assuming. If the recoverable quantities resulting from large enough portfolios of projects are aggregated stochastically, the aggregated value, having a 10% probability of being exceeded, is relevant. It is very demanding to produce but possibly reliable.

The same concern for relevance applies to proved reserves. We therefore reiterate the statement we made in our comments to the Concept release that the report should be based on proved plus probable (near expected value) quantities as the principal measure. We do not see the need to report the other two, if not to allow for a continuation of the time series developed through earlier reporting. This may be a basis for reporting proved reserves in addition, in a transition period, but then as additional information.

. Should we require, rather than permit, disclosure of probable or possible reserves? If so why?

Reporting the quantities of reserves with a 50% probability of being exceeded of reserves should be required.

. Should we adopt the proposed definitions of probable reserves and possible reserves? Should we make any revisions to those proposed definitions? If so, how should we revise them?

We support the use of the definitions proposed with the addition that the deterministic and probabilistic estimates should be equivalent. This provides clarity to the meaning of the deterministic terms, and conformance between the results obtained from the two methods.

. Are the proposed 50% and 10% probability thresholds appropriate for estimating probable and possible reserves quantities when a company uses probabilistic methods? Should probable reserves have a 60% or 70% probability threshold? Should possible reserves have a 15% or 20% probability threshold? If not, how should we modify them?

The UNFC and the SPE/PRMS thresholds of 50% and 10% are well established and respected. They should be used.

From a purist point of view, one could argue that the expected value (mean value) should replace the 50% threshold value. It is however recognised that the determination of probabilities in reserves evaluation cannot be done objectively based on measured observations. It must be based to some extent on judgement. The ability to judge probabilities is not of such a quality as to ascertain with confidence the difference between the mean value and the 50% threshold value. Additionally, a 50% threshold value as a proxy for the mean will normally err on low side, considering the log-normal nature of the probability distributions for the volume of geometric bodies.

A.5 F. Definition of ‘‘Proved Developed Oil and Gas Reserves’’

. Should we revise the definition of proved developed oil and gas reserves, as proposed? Should we make any other revisions to that definition? If so, how should we revise it?

Yes, you should revise the definition of proved developed oil and gas reserves as proposed.

A.6 G. Definition of ‘‘Proved Undeveloped Reserves’’

A.6.1 Proposed Replacement of Certainty Threshold

. Are the proposed revisions appropriate? Would the proposed expansion of the PUDs definition create potential for abuses?

No. It is not appropriate to define proved undeveloped reserves, as they are implicitly defined as the difference between proved reserves and proved developed reserves. This is reflected in the current rules by not requiring filers to report proved undeveloped reserves.

Alternatively, one of the other two definitions must be deleted or a fourth category of reserves must be introduced for the residual. However, the substance contained in the proposed definition of proved undeveloped reserves may be introduced in the definitions that the Commission chooses to retain. They act to clarify the definition of proved reserves as does the current definition.

. Should we replace the current ‘‘certainty’’ threshold for reserves in drilling units beyond immediately adjacent drilling units with a ‘‘reasonable certainty’’ threshold as proposed?

Yes.

. Is it appropriate to prohibit a company from assigning proved status to undrilled locations if the locations are not scheduled to be drilled more than five years, absent unusual circumstances, as proposed? Should the proposed time period be shorter or longer than five years? Should it be three years? Should it be longer, such as seven or ten years?

Both the UNFC and the SPE PRMS subdivide reserves into three categories:

1. **On production**
2. **Approved for development**
3. **Justified for development**

We recommend the Commission to use this subdivision where the quantities affected by "unusual circumstances" are recognised as quantities justified for development and distinguished from quantities approved for development. There will be less need to assign a time period to the quantities that are justified for development. If one is desired, the proposed text is supported.

. Should the proposed definition specify the types of unusual circumstances that would justify a development schedule longer than five years for reserves that are classified as proved undeveloped reserves?

Yes. See our comment under A3.3 above.

A.6.2 Proposed Definitions for Continuous and Conventional Accumulations

. Should we provide separate definitions of conventional and continuous accumulations, as proposed? Would separate disclosure of these accumulations be helpful to investors?

Yes, definitions should be provided as proposed. However, the word conventional should be avoided as it is likely to be short lived. In 10 years or less, production from certain continuous accumulations will be considered to be conventional production.

. Should we revise our proposed definition of ''continuous accumulations'' in any way? For example, should the proposed definition provide examples of such accumulations? If so, how should we revise it?

No, you should not revise it. In the definition of reserves, you propose to introduce a reserves reference point at which the (uncertain) quantities produced by a project (reserves) are defined; the need for prescriptive detail with respect to the source of these quantities is reduced. Emphasis shifts to the projects, their costs, products and value.

. Should we revise our proposed definition of ''conventional accumulations'' in any way? If so, how should we revise it?

No, you should not change your proposed definition, except for the name. "Pools" or some such short generic description, aligning with the term "continuous accumulations" would be equally appropriate and clearer in the longer term.

A.6.3 Proposed Treatment of Improved Recovery Projects

. Should we expand the definition of proved undeveloped reserves to permit the use of techniques that have been proven effective by actual production from projects in an analogous reservoir in the same geologic formation in the immediate area or by other evidence using reliable technology that establishes reasonable certainty?

Yes.

A.7 H. Proposed Definition of Reserves

. Is the proposed definition of ‘‘reserves’’ appropriate? Should we change it in any way? If so, how?

No, it is not fully appropriate.

The proposed definition of reserves is not sufficiently clear with respect to projects. In the UNFC and the SPE PRMS it is clear that the object of classification is the project and the proved probable and possible quantities are the low best and high estimates of what the project will produce. It is not possible to have different projects underlying the three estimates. If different projects are considered, they would each be classified independently as reserves, contingent or in the case of undiscovered resources, prospective resources depending on their maturity.

Should different projects be allowed to underlie the three estimates, then the 90% threshold value on proved reserves would be affected by the projects producing unproved reserves loading the high end of the probability distribution.

We recommend adaptation of the SPE PRMS definition. The SPE PRMS definition is as follows:

> ***“Reserves are those quantities of petroleum anticipated to be commercially recoverable by the application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.”***

The term “defined conditions” should be specified.

The word “commercial” is of critical importance in separating the projects qualifying for producing reserves from those producing contingent resources. The SPE-PRMS provides the following specification:

> **“2.1.2 Determination of Commerciality**
>
> **Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:**
>
> - **Evidence to support a reasonable timetable for development.**
> - **A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:**
> - **A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.**
> - **Evidence that the necessary production and transportation facilities are available or can be made available:**

- **Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.**

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests."

The UNFC and the SPE PRMS provides further clarity in delineating reserves through their definition of Contingent Resources.

A.8 I. Other Proposed Definitions and Reorganization of Definitions

. Are these additional proposed definitions appropriate? Should we revise them in any way?

Our comments are:

. ''Analogous formation in the immediate area,'' which appears in the definition of proved reserves;

The acceptability of this definition is contingent upon the latter part of the sentence allowing the use of other evidence using reliable technology that establishes the reasonable certainty of the engineering analysis on which the project or program is based. If this is deleted for any reason, we would recommend that the geographic proximity criterion be removed from the definition of analogous formation. It is not the location of the analogue that matters, but its properties established through geologic history.

. ''Condensate''

No comment

. ''Development project''

No comment

. ''Estimated ultimate recovery,'' which appears in the definition of proved reserves;

No comment

. ''Resources,'' which are often confused with reserves.

No comment

. Are there other terms that we have used in the proposal that need to be defined? If so, which terms and how should we define them?

No comment

. Should we alphabetize the definitions, as proposed?

Yes

Would any undue confusion result from the reordering of existing definitions?

No

App B Proposed Amendments To Codify the Oil and Gas Disclosure Requirements in Regulation S–K

B.1 A. Proposed Revisions to Items 102, 801, and 802 of Regulation S–K

. Is the proposed amendment to Instruction 3, limiting it to extractive activities other than oil and gas activities, appropriate? Should we simply call them mining activities?

. Are there any other aspects of Item 102 that we should revise? If so, what are they and how should they be revised?

No Comment

B.2 B. Proposed New Subpart 1200 to Regulation S-K Codifying Industry Guide 2 Regarding Disclosures by Companies Engaged in Oil and Gas Producing Activities

B.2.1 2. Proposed Item 1201 (General Instructions to Oil and Gas Industry-Specific Disclosures)

. Are the proposed general instructions to Subpart 1200 clear and appropriate? Are there any other general instructions that we should include in this proposed Item?

Yes we find it clear but refer to our comments to the different disclosure proposed (Item 1202 to 1209) under the relevant questions raised regarding the relevance of the proposed disclosure.

. For disclosure items requiring tabulated information, should we require companies to adhere to a specified tabular format, instead of permitting companies to reorganize, supplement, or combine the tables?

Your proposal to permit companies to reorganize, supplement or combine tables is supported. Your proposed introduction of XBRL impacts our view in this respect.

. In particular, should we permit a company to disclose reserves estimates from conventional accumulations in the same table as it discloses its reserves estimates from continuous accumulations?

Yes

B.2.2 3. Proposed Item 1202 (Disclosure of Reserves)

B.2.2.1 i. Oil and Gas Reserves Tables

. Should we permit companies to disclose their probable reserves or possible reserves? Is the probable reserves category, the possible reserves category (or both categories) too uncertain to be included as disclosure in a company's public filings? Should we only permit disclosure of probable reserves? What are the advantages and disadvantages of permitting disclosure of probable and possible reserves, from the perspective of both an oil and gas company and an investor in an oil and gas company that chooses to provide such disclosure? Would investors be concerned by such disclosure? Would they understand the risks involved with probable or possible reserves?

Proved plus probable reserves (the best estimate/ the quantity with a 50% chance of being exceeded) should not only be permitted but also required to be disclosed. The definition should make the reader aware of the uncertainty of the estimate. Informed investors are well trained to understand the risks involved. The advantage of disclosing this quantity is that it is near relevant in the sense that the sum will be near the 50% threshold for the aggregate, and in the sense that business decisions are guided more by the expectation than by the high and low estimates. The high and low estimates are mostly used to assess uncertainties and to establish the value of their associated options to capture the opportunities and mitigate the risks in an operational sense. Many of these opportunities and risks are non-systematic and of less concern to a well diversified investor.

. Would the proposed disclosure requirements provide sufficient disclosure for investors to understand how companies classified their reserves?

Yes

. Should the proposed Item require more disclosure regarding the technologies used to establish certainty levels and assumptions made to determine the reserves estimates for each classification?

No. There should not be a prescriptive requirement with respect to technologies as that will weaken the functional requirement for accuracy of the estimates. Consequently, there should not be a requirement to disclose the technologies used. On the other hand, the filer should not be prevented from disclosing such information at its own discretion. The Commission should remain silent with respect to such disclosures.

. Should companies be required to provide risk factor disclosure regarding the relative uncertainty associated with the estimation of probable and possible reserves?

No. It is inherent in the definition that there must be equivalence in deterministic and probabilistic estimation. This defines the uncertainty. The risk that this uncertainty represents depends on the consequences that the outcomes have. That must be dealt with in a wider context.

This comment applies to the risk of misjudging the quantities of reserves and not to the risk of misjudging their value.

. Should we allow filers to report sums of proved and probable reserves or sums of proved, probable, and possible reserves? Or, to avoid misleading investors, should we allow only disclosure of each category of reserves by itself and not in sum with others, as proposed?

Sums of proved plus probable reserves should be reported. Other sums are misleading for reasons explained.

. Should we require disclosure of probable or possible reserves estimates in a company's public filings if that company otherwise discloses such estimates outside of its filings?

Proved plus probable reserves should be required under all circumstances.

. Should we require all reported reserves to be simple arithmetic sums of all estimates, as proposed? Alternatively, should we allow probabilistic aggregation of reserves estimated probabilistically up to the company level? If we do so, will company reserves estimated and aggregated deterministically be comparable to company reserves estimated and aggregated probabilistically?

Only arithmetic sums of proved plus probable reserves should be disclosed. Before considering a requirement to disclose a probabilistic aggregation of proved only or proved plus probable plus possible reserves, it will be important to revisit how these aggregates relate to their equivalent values. We believe that in general, it will not be possible for the reader to correlate these estimates of reserves to their values with any degree of accuracy. Not only do the costs, revenues, taxes and time schedules vary between projects, but they may also vary in nonlinear ways for individual projects. Economies of scale make high outcomes disproportionately more valuable than low ones. Contracts often distribute high and low values obtained differently. He combined effect is that the value of 90%, 50% or 10% thresholds of reserves does not, in general, correspond to the 90%, 50% or 10% thresholds of the economic project values that accrue to the filer.

We believe therefore that probabilistic aggregates should be permitted, but since their correlation to value is likely to be low, they should not be required.

. Should we revise the proposed form and content of the table? If so, how should we revise the table's form or content?

Yes. There should be a focus on indicators of the value of reserves.

. Should we eliminate the current exception regarding the disclosure of estimates of resources in the context of an acquisition, merger, or consolidation if the company previously provided those estimates to a person that is offering to acquire, merge, or consolidate with the company or otherwise to acquire the company's securities? If so, would this create a significant imbalance in the disclosures being made to the possible acquirer, as opposed to the company's shareholders?

No comment.

B.2.2.2 ii. Optional Reserves Sensitivity Analysis Table

. Should we adopt such an optional reserves sensitivity analysis table? Would such a table be beneficial to investors? Is such a table necessary or appropriate?

Yes to all three questions.

. Should we require a sensitivity analysis if there has been a significant decline in prices at the end of the year? If so, should we specify a certain percentage decline that would trigger such disclosure?

We do not support the use of historical prices. This question does therefore not arise.

. Should we revise the proposed form and content of the table? If so, how should we revise the table's form or content?

In conformance with the view that the revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves, which should help investors evaluate the relative value of oil and gas companies, we believe this effort should be focused more directly on values, showing sensitivities of the value indicators that the Commission may choose to use, such as the Standardized measure of net present value of future cash flow.

. As noted above in this release, SFAS 69 currently uses single-day, yearend prices to estimate reserves, while the reserves estimates in the proposed tables would be based on 12-month average year-end prices. If the FASB elects not to change its SFAS 69 disclosures to be based on 12-month average year-end prices, should we require reconciliation between the proposed Item 1202 disclosures and the SFAS 69 disclosures? What other means should we adopt to promote comparability between these disclosures?

Our primary view is that reserves estimates should be based on the same assumptions, whether for reserves reporting purposes or accounting purposes. Should the Commission maintain the view that different price assumptions should be made for the two purposes, then presumably the difference in price would also be the only reconciling item. The most important disclosure should therefore be on why one would use two different sets of price assumptions rather than reconciling tables. In short, we oppose the use of different price assumptions, and a reconciliation should not be necessary.

B.2.2.3 iii. Geographic Specificity With Respect to Reserves Disclosures

. Should we provide the proposed guidance about the level of specificity required when a company discloses its oil and gas reserves by ''geographic area''?

No.

We disagree with this and propose that the geographic subdivision that currently applies be continued. The reasons for recommending not requiring the granularity proposed is:

1. **It can easily lead to disclosure of field or project specific information, particularly if one considers the aggregate effect of own and partner disclosures.**
2. **Such field and project specific information is sensitive commercially.**
3. **Many E&P contracts define the information to be confidential, not to be disclosed without the specific agreement of all partners in the partnerships, including at times Government.**
4. **Individual field and project specific information is of much lower reliability than aggregated numbers for a portfolio. While management may assume responsibility for aggregated estimates being materially correct, this is much more difficult, or impossible, in the case of individual estimates where a range of values may be considered to be equally probable. The party carrying the burden of proof will be prone to loose the argument unless very extensive efforts are made. If these do not affect the aggregated values or the business decisions that need to be taken, the efforts will be of no value to the investor, or to the filer.**

. Are the proposed 15% and 10% thresholds appropriate? Should either, or both, of these percentages be different? For example, should both be 15%? Should both be 10%? Would 5% or 20% be a more appropriate threshold for either or both?

If thresholds need to be introduced, they should be 20% or more for both in order to mitigate the undesired effects.

. What would be the impact to investors if companies are permitted to omit disclosures based on the individual field or basin due to concerns related to competitive sensitivities? Would investors be harmed if disclosure based on the individual field or basin is omitted due to concerns related to competitive sensitivities? Is there a better way to provide disclosure that a company heavily dependent on a particular field or basin may be subject to risks related to the concentration of its reserves?

Disclosure that reduces competitive value is to the detriment of the existing investors while, in the case of disaggregated information about proved reserves and wells drilled, of only marginal value to prospective investors.

Project specific information may assist an analyst in assessing the value of the project, particularly since the reserves and other information covered in the Proposed rule is only indirectly correlated to value. To compensate for this disadvantage, we recommend that the Commission looks into ways of enhancing the communication of project value.

Dominant risks related to resource concentration are best communicated through the MD&A[1].

. Would greater specificity cause competitive harm?

Yes.

If so, how can the rules mitigate the risk of harm?

Do not change existing requirements.

. In the event that the FASB does not amend SFAS 69, should we require companies to supplement their SFAS 69 disclosure with greater geographic specificity? If the FASB does not amend SFAS 69, should we require that companies reconcile the differences between the reserves estimates shown in the SFAS 69 disclosure with the estimates presented in the proposed tables?

SFAS 69 should apply.

B.2.2.4 iv. Separate Disclosure of Conventional and Continuous Accumulations

. Should we require separate disclosure of conventional accumulations and continuous accumulations, as proposed?

No. You should permit it.

. Should we permit combining of columns if the product of the oil and gas producing activity is the same, such as natural gas, regardless of whether the reserves are in conventional or continuous accumulations?

Yes.

B.2.2.5 v. Preparation of Reserves Estimates or Reserves Audits

. Should we require companies to disclose whether the person primarily responsible for preparing reserves estimates or conducting reserves audits meets the specified qualification standards, as proposed? Should we, instead, simply require companies to disclose such a person's qualifications?

. Should we require disclosure regarding a person's objectivity when a company prepares its reserves estimates in-house? Should the proposed disclosures regarding objectivity be required only if a company hires a third party to prepare its reserve estimates or conduct a reserves audit, as proposed?

. If a company prepares its reserves estimates in-house, should we require disclosure of any procedures that the company has taken to preserve that person's objectivity? Should we require disclosure of whether the internal person meets specified objectivity criteria? For example, should we apply the some of the same criteria that we propose to apply to third party preparers? If so, which ones?

. Consistent with the SPE's auditing guidance regarding internal auditors, should we require companies to disclose whether that person (1) is assigned to an internal-audit group which is (a) accountable to senior level management or the

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[1] When we refer to MD&A we support the Commissions view that it can be placed adjacent to the tables where the quantitative information is disclosed where appropriate and not necessarily in the formal MD&A section of Form 20-F.

board of directors of the company and (b) separate and independent from the operating and investment decision making process of the company and (2) is granted complete and unrestricted freedom to report, to one or more principal executives or the board of directors, any substantive or procedural irregularities of which that person becomes aware?

. Should we require disclosure with other specific independence or objectivity standards and, if so, what?

. Should we revise any of the proposed provisions regarding a person's objectivity or technical qualifications? Should the proposal require disclosure of other criteria that would have bearing on determining whether the person is objective or qualified?

. Should a company be required to present risk factor disclosure if its reserves estimates were not prepared by a person meeting the objectivity and technical qualifications?

. Because of the inherent uncertainty regarding estimates of probable and possible reserves, should we require the proposed disclosure only if a company chooses to disclose probable or possible reserves?

. Should we require that a third party prepare reserves estimates or conduct a reserves audit if a company chooses to disclose probable or possible reserves estimates?

. Should we require the proposed disclosure only if the company is using technologies other than those which are allowed in our current definitions to establish levels of certainty?

First of all, CEO and CFO are ultimately responsible for the content of the filed report as well as the design and workings of internal controls in place to secure the quality of the filed report, including the report on oil and gas reserves and activities. Secondly, StatoilHydro is in general in support of a functional requirement including disclosure of the internal control measures that the filer has implemented, operated and assessed to ensure that the report on oil and gas reserves and activities is correct rather than prescriptive requirements on the level of individuals or organisational units. If anything, the Commission could consider the need for additional guidance on required internal controls over the reporting of oil and gas reserves and activities, unless the existing guidance on internal controls over financial reporting is also applicable for the reporting of oil and gas reserves and activities.

B.2.2.6 vi. Contents of Third Party Preparer and Reserves Audit Reports

Should we require a company to file reports from third party reserves preparers and reserves auditors containing the proposed disclosure when the company represents that a third party prepared its reserves estimates or conducted a reserves audit?

Yes.

As an alternative, should we not require that the third party's report be filed, but that the company must provide a description of the third party's report? If so, should we specify that the company's description of the third party's report should contain the information that we propose to require in the third party's report?

Should we specify the disclosures that need to be included in third party reports?

Yes.

If so, is the disclosure that we have proposed for the reserves estimate preparer's and reserves auditor's reports appropriate?

Yes.

Should these reports contain more or less information? If they should include more information, what other information should they include? If less, what proposed information is not necessary?

In an audit, should we specify the minimum percentage of reserves that should be examined and determined to be reasonable? If so, what should that percentage be? Should it be 50%, 75%, 90% or some other percentage? If so, why?

80% would likely be sufficient recognising that the last 20% may be contained in a large number of less material assets that might require a disproportionate amount of work to little effect.

If the company engages multiple third parties to conduct reserves audits on different portions of its reserves, should the definition of reserves audit be conditioned on each third party evaluating at least 80% of the reserves covered by its reserves audit, as proposed?

No. The requirement should be on the company's reserve base.

Is the scope of a reserves audit defined by geographic areas? If so, should the definition of a reserves audit be based on the third party's evaluation of 80% of the reserves located in the geographic areas covered by the reserves audit?

No. The requirement should be on the company's reserve base.

Would disclosure that a company has hired a third party to audit only a portion of its reserves be confusing to investors? Is there a danger that investors will not be able to ascertain the extent of the reserves audit? Should we require that a company could not disclose that it has conducted a reserves audit unless 80% of all of its reserves have been evaluated by a third party or, if the company hires multiple third parties, by all of the third parties collectively?

In any case the company should disclose its internal control procedures. A partial audit could be part of such procedures, but not necessarily the full procedure.

Is the proposed definition of ‘‘reserves audit’’ appropriate?

Yes.

Should we revise this proposed definition in any way?

No.

B.2.2.7 vii. Solicitation of Comments on Process Reviews

. Should we require disclosure of whether a company has conducted a process review? Notwithstanding the relative lack of rigor of a process review compared to a reserves audit, would investors find such information useful?

. The proposal does not prohibit disclosure of process reviews. Is there a danger that the public may be confused by such disclosure? Should we prohibit disclosure of any type of reserves related activity other than the preparation of the reserves estimates or a reserves audit?

The internal control procedures should be disclosed in summary form. They may or may not include process reviews by third parties.

B.2.3 4. Proposed Item 1203 (Proved Undeveloped Reserves)

. Should we adopt the proposed table? Alternatively, should we simply require companies to reclassify their PUDs after five years?

We refer to our comment to item G. Definition of ''Proved Undeveloped Reserves'' we propose to subdivide the undeveloped reserves into the quantities produced through projects that have been approved for development and those produced through projects that have been justified for development. This will inform investors of the quantities demanding financial resources in the near term and quantities that will not. The disclosures should reflect this subdivision. The measure would make it less necessary to impose a time limit on proved undeveloped reserves. There should not be a requirement to reclassify reserves after 5 years.

. Should the table require disclosure of other categories of changes to the status of PUDs, such as acquisitions, removals, and production? Should we add any categories?

Yes. You should add a category for quantities produced through justified projects and define them in accordance with the SPE PRMS definition.

. Some of the abuse related to PUD disclosure may be related to companies' desire to show proved reserves in light of our prohibition on disclosure of probable reserves. Would the proposed rules permitting disclosure of probable reserves reduce the incentive to categorize reserves as PUDs?

No. In currently accepted terminology (UNFC and SPE PRMS) proved, probable and possible reserves are low, best and high estimates of the quantities to be produced by the same projects, not different projects. Undeveloped reserves are by definition produced by projects that are additional to the ones producing Developed reserves.

If so, is the proposed table necessary?

No. With a subdivision of Undeveloped reserves, there is not a need to disclose the aging of Undeveloped reserves. The cost of converting undeveloped to developed reserves should be considered in the broader context of providing direct indicators of reserve values.

. Should we require disclosure of the reasons for maintaining PUDs that have been classified as PUDs for more than five years, as proposed? If not, why not?

This should be handled in the MD&A.

. Should we require a company to disclose its plans to develop PUDs and to further develop proved oil and gas reserves, as proposed? If not, why not?

Reference is made to our comment to "iii. Geographic Specificity With Respect to Reserves Disclosures". The company should report at the portfolio level and not at the project level. This would preclude a rule requiring discussion of individual development plans. Plans that affect the company materially should be discussed in the MD&A.

. Should we require the company to discuss any material changes to PUDs that are disclosed in the table?

Yes.

If not, why not?

B.2.4 5. Proposed Item 1204 (Oil and gas production)

. Should we adopt the proposed table?

Yes, subject to keeping the existing SFAS 69 geographic subdivision.

. Should the disclosure be made based on the proposed definition of ‘‘geographic area,’’ or should we continue to follow the definition set forth in SFAS 69?

You should continue to use SFAS 69 for reasons explained in our comment to “iii. Geographic Specificity With Respect to Reserves Disclosures” above.

. Should we eliminate the instructions listed above, as proposed? If not, which instructions should we retain? Please explain why those instructions continue to be useful.

Provided the concept of a reserves reference point is implemented rigorously, the listed instructions should be eliminated as proposed.

B.2.5 6. Proposed Item 1205 (Drilling and other exploratory and development activities)

. Should we adopt the proposed table? Should the disclosures be made based on the definition of ‘‘geographic area’’ in proposed Item 1201(d)?

No.

. Should we require separate disclosure about the two new proposed categories of wells-extension wells and suspended wells?

No.

Does distinguishing these types of wells from exploratory wells and dry wells provide enough clarity regarding the types of exploratory or development activities?

No.

The correlation between the detailed well information and the company value is, in general, too weak to justify the continuation of reporting these details. The Commission should be silent on the issue, not requiring, encouraging, or preventing the company to disclose this information in its filings or outside as part of its regular information to the public.

B.2.6 7. Proposed Item 1206 (Present activities) Proposed Item 1206 would codify existing Item 7 of Industry Guide 2, which calls for disclosure of present activities, including the number of wells in the process of being drilled

. Should the disclosure of present activities be made based on the definition of ‘‘geographic area’’ in proposed Item 1201(d)?

No.

. Should we adopt any other changes to the disclosures currently set forth in existing Item 7 of Industry Guide 2 that we propose to codify in Item 1206?

For the reasons mentioned in our comment above, the Commission should be silent on the issue, not requiring, encouraging, or preventing the company to disclose this information in its filings or outside as part of its regular information to the public.

B.2.7 8. Proposed Item 1207 (Delivery Commitments)

. Are the proposed revisions appropriate? Do the proposed revisions make any unintended substantive changes to the existing disclosures?

. Should we adopt any substantive changes to the disclosures currently set forth in Item 8 of Industry Guide 2 that we propose to codify in Item 1207?

. Is this disclosure requirement still necessary? Do oil and gas companies still enter into such delivery commitments? Are they material?

While perhaps not material for most filers, delivery commitments could still arise from the creative processes of adapting contracts to a fiercely competitive environment.

B.2.8 9. Proposed Item 1208 (Oil and gas properties, wells, operations, and acreage)

B.2.8.1 i. Enhanced Description of Properties Disclosure Requirement

. Are the proposed disclosure enhancements regarding oil and gas properties appropriate?

Yes, in part.

Would this enhanced disclosure be helpful to investors?

It helps the reader understand the report. It is directly useful only to the extent the information is directly correlated to company value. Well information should not be required, but should be permitted. There may be other factors of equal or greater importance affecting the cumulative production of a project during a license term, and company value.

. Should the disclosures be made based on the definition of ‘‘geographic area’’ in proposed Item 1201(d)?

No.

. Do we need to define any of the terms in the proposed language?

Not when the requirement to report wells is removed.

B.2.8.2 ii. Wells and Acreage

. Is the proposed table appropriate? Is there a better way to disclose such information?

. Should the disclosures be made based on the definition of ‘‘geographic area’’ in proposed Item 1201(d)?

. Is it necessary to disclose wells and acreage in conventional accumulations separate from wells and acreage in continuous accumulations, as proposed?

. Is this disclosure requirement still necessary? Is disclosure of the number of wells and acreage material? Should we require the disclosures related to wells and acreage only if there is a high concentration of production or reserves attributable to a few wells or limited acreage? If so, should we specify what that concentration would be?

The correlation between this information and company value is too weak to justify a reporting requirement. The commission should remain silent on wells and acres thus

permitting the company to report it where appropriate as part of its general public information activity.

B.2.8.3 iii. New Proposed Disclosures Regarding Extraction Techniques and Acreage

. Should we require more specific disclosure regarding extraction activities that do not involve wells?

No.

Should this proposed item remain open-ended to permit description of unanticipated technologies?

Yes.

. Is the proposed disclosure for unproved properties appropriate?

It should be by geographic area as defined in SFAS 69.

Should the proposed disclosure for unproved properties be set forth in proposed Item 1208?

Yes.

Should we move such disclosure to the reserves table in proposed Item 1202, where reserves are discussed?

No. It should not be easy to confuse unproved properties with unproved reserves. Unproved properties may hold prospective resources only and not reserves.

B.2.9 10. Proposed Item 1209 (Discussion and Analysis for Registrants Engaged in Oil and Gas Activities)

. Proposed Item 1209 is not intended to increase a company's disclosure requirements, but specify disclosures already required generally by MD&A. Is such an item helpful?

. Are the proposed topics that an oil and gas company should consider discussing as part of MD&A, whether in the main MD&A section or in conjunction with the relevant table, appropriate?

While it is appropriate to require an account of the company's ability to convert undeveloped reserve to developed reserves, it is not appropriate to require the company to report on its conversion of possible reserves to probable reserves and probable reserves to proved reserves. This follows from the fact that proved, probable and possible reserves do not reflect project status, but the uncertainty associated with the production from a project with a given status (developed or undeveloped). Efforts will be made to reduce this uncertainty when required to make prudent decisions. If the resolution of the uncertainty does not impact the decisions to be made, the information will be of no value to the project. Requiring it in the financial reporting will destroy value for the investor. Many of the uncertainties at hand are non-systematic in nature and of limited consequence to a well diversified investor.

Are there other topics that an oil and gas company should consider discussing?

. Should we permit such discussions in conjunction with the relevant table as proposed? Would this aid comparability of the disclosures? Or should we keep MD&A as a self-contained section?

You should keep the MD&A as a self-contained section. To the extent that such a discussion is important for the understanding of the business and the company's performance and prospects, our interpretation is that the filer is already required to make such disclosures in the annual report. It should therefore not be required to make additional disclosures in conjunction with the reserves report.

App C Proposed Conforming Changes to Form 20–F

. Should we delete Appendix A and refer to Subpart 1200 with respect to Form 20–F, as proposed? Why? Should we expand the requirements of Form 20–F to require more disclosure than currently required by Appendix A, as proposed?

Relevant disclosure requirements should be the same for all filers.

. Conversely, should we only update Appendix A to reflect the proposed new definitions and formats for disclosing reserves and production?

No comment.

. Would the proposed reference to Subpart 1200 in Form 20–F significantly change the information currently disclosed by foreign private issuers? If so how? Would such a change be appropriate?

The proposed change would potentially increase the disclosure requirements. Special care should therefore be taken to ensure that the increased disclosures are of relevance and significant importance to the users of the financial information. Information that is merely "nice to know" should not be required but optional.

. Is the proposed exception for foreign laws that prohibit disclosure about reserves and agreements appropriate? Do such laws affect domestic companies as well? Should Subpart 1200 have a general instruction with respect to such foreign laws?

The exception is relevant to the industry; domestic as well as foreign filers and a general instruction with respect to such foreign laws is appropriate.

. Are the proposed revisions to Instructions to Item 4.D appropriate with respect to foreign private issuers that have extractive activities other than oil and gas producing activities?

No comment

App D Impact of Proposed Amendments on Accounting Literature

D.1 B. Change in Accounting Principle or Estimate

. Are the proposed changes more properly characterized as a change in accounting principle or a change in estimate under SFAS 154?

The proposed changes should be considered changes in estimate because the fundamental principles are the same, while the estimates have changed due to new assumptions.

. Would it be appropriate to consider the changes as a change in accounting principle, but specify that no retroactive revision of past years would be required?

Yes. Prior year figures should not have to be restated since that would effectively entail backdating of estimates; one can not make estimates today with today's knowledge and pretend as if estimating based on only prior year knowledge.

. If we required retroactive revision of past years, would companies have the historical engineering and scientific data to make such revisions? If not, are there alternatives to retroactive revision that we should consider?

While the data might be available, one can not pretend not knowing what we know today, and this knowledge will surely affect judgements that must be made for all estimates. One mitigating alternative to retroactive revision could be a table that, on the aggregate reconcile the closing balance of last year with the restated opening balance of the current year.

D.2 C. Differing Capitalization Thresholds Between Mining Activities and Oil and Gas Producing Activities

. How should we address these inconsistencies between oil and gas accounting rules and mining accounting rules?

The adoption of a project status based classification will lessen the differences.

. Should we permit companies that extract, through mining methods, materials from which oil and gas can be produced to continue to capitalize costs under mining rules, or should we require them to capitalize costs based on oil and gas rules? Are there circumstances involved with mining operations, different from oil and gas operations, that justify capitalization of costs of proved plus probable reserves, as opposed to only costs of proved reserves?

Consistent with other comments above, the main output should determine which rules should apply; If the project objective is to produce oil, then that should be the basis for recognising oil reserves irrespective of how the oil is extracted from the ground. The same should apply for accounting; if the project goal is to produce oil, then oil and gas rules should apply, even if mining methods are applied to extract the oil.

The same argument can be made for reporting of project value; the investor is interested in the overall value of the project, not merely the value of different extractive activities or of upstream activities if mid-stream activities represent an integral part of the project.

D.3 D. Price Used To Determine Proved Reserves for Purposes of Capitalizing Costs

. Would the effect of such changes be material or have a material effect on historical amortization levels?

. Would the effect of such changes be material or have a material effect on comparability? Please provide any empirical evidence to support your conclusion.

. Would it be appropriate to continue to require the use of the year-end price for purposes of determining reserves for purposes of amortization expense while using a different price for purposes of disclosing reserves estimates in Commission filings? This would result in a different value associated with the use of the term ''proved reserves'' for purposes of disclosure, as opposed to the use of that term for purposes of accounting. Would this be confusing? Should we use a different term? Should we otherwise clarify the two different meanings of that term in different contexts?

The effects will vary significantly between assets but are not expected to be material at a consolidated level, and are as such deemed to not materially affect comparability between

companies and periods. We strongly oppose any requirement to use different sets of price assumptions for reserves reporting and accounting purposes, respectively.

App E Impact of the Proposed Codification of Industry Guide 2 on Other Industry Guides

. Is it appropriate to codify Industry Guide 2 separately from the other industry guides? Should we merely amend Industry Guide 2 and codify it with all of the other industry guides when they have been updated?

No comment

. Would the codification of Industry Guide 2 overrule or otherwise affect any of the disclosures required in the other Industry Guides?

No comment

App F Solicitation of Comment Regarding the Application of Interactive Data Format to Oil and Gas Disclosures

. Should we adopt rules that require oil and gas disclosures to be provided in interactive data format? Instead of requiring such formatting, should we only permit the filing of oil and gas disclosures in interactive data format? What are the principal factors that we should consider in making these decisions?

We support the introduction of electronic tagged oil and gas disclosures and that this frame should be required within a reasonable time.

. If we require oil and gas disclosures to be filed in interactive data format, should we provide for a voluntary phase-in period to create a well developed standard list of electronic tags? Without a requirement, would the development of products for using interactive data meet the needs of investors, analysts, and others who seek to use interactive data? Would a large percentage of oil and gas companies provide interactive data voluntarily and follow the same standard, if not required to do so?

We believe that a voluntary period is needed in order for companies to prepare solutions for this type of reporting and also for developing and verification of the needed tag standard.

. Would investors, analysts, and others find presentation of oil and gas disclosures helpful if presented in interactive data format? In what ways would such users of the information find such a format beneficial?

We believe that an interactive data format will provide for more effective and precise analyses of these disclosures.

. As we note above, there is not currently a well-developed standard list of electronic tags for the oil and gas disclosures. Are there any obstacles to creating a useful standard list of electronic tags for the oil and gas disclosures? Is the type of data presented in the proposed table conducive to interactive data format? Would it be particularly difficult to create standard electronic tags for any of the proposed data? Would there be any obstacles to providing comparable data in interactive format?

No, we see no obstacles or particular difficulties in creating a tag standard for the proposed data.

. Would it be useful for the data in the proposed tables to interact with other data in Commission filings? If so, which data?

No comment

. If we adopt rules requiring oil and gas disclosures in interactive data format, should we require the use of the eXtensible Business Reporting Language (XBRL) standard? Are any other standards becoming more widely used or otherwise superior to XBRL? What would the advantages of any such other standards be over XBRL?

We support a solution and requirement according to the eXtensible Business Reporting Language (XBRL) standard.

App G Proposed Implementation Date

. Should we provide a delayed compliance date, as proposed above? If so, is the proposed date appropriate? Should we provide more or less time for companies to familiarize themselves with the proposed amendments?

. If we provide a delayed compliance date, should we permit early adoption by companies?

We support the proposed the proposed date of January 1, 2010, as the date for company's reporting to be compliant with the new requirements and we believe that an optional early adoption is not beneficial.

App H General Request for Comment

We request and encourage any interested person to submit comments regarding:

. The proposed rule changes and additions that are the subject of this release;

. Additional or different changes; or

. Other matters that may have an effect on the proposals contained in this release. We request comment from the point of view of registrants, investors, and other users of information about the disclosures that should be required with regard to oil and gas companies and the corresponding definitions of terms used in those disclosure requirements.

Reference is made to our cover letter and principal comments

App I Paperwork Reduction Act

We request comment in order to evaluate the accuracy of our estimate of the burden of the collections of information. Any member of the public may direct to us any comments concerning the accuracy of these burden estimates. Persons who desire to submit comments on the collection of information requirements should direct their comments to the OMB, Attention: Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Washington, DC 20503, and should send a copy of the comments to Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090, with reference to File No. S7–15–08. Requests for materials submitted to the OMB by us with regard to this collection of information should be in writing, refer to File No. S7–15–08, and be submitted to the Securities and Exchange Commission, Records Management Branch, 100 F Street, NE., Washington, DC 20549–1110. Because OMB is required to make a decision concerning the collections of information between 30 and 60 days after publication, your comments are best assured of having their full effect if OMB receives them within 30 days of publication.

The estimated average additional burden of 35 hours per annual report or registration statement assumesseems to be significantly underestimated.

App J Cost-Benefit Analysis

We request comment on all aspects of the Cost-Benefit Analysis, including identification of any additional costs or benefits of, or suggested alternatives to, the proposed amendments. We also request that those submitting comments provide, to the extent possible, empirical data and other factual support for their views.

We have no comment or empirical data to support these analyses.

App K XII. Consideration of Burden on Competition and Promotion of Efficiency, Competition, and Capital Formation

We request comment on whether the proposals, if adopted, would promote efficiency, competition, and capital formation or have an impact or burden on competition. Commenters are requested to provide empirical data and other factual support for their views, if possible.

One of StatoilHydro's main comments to the proposed rules is the lack of reference to value and what drives the value of oil and gas activities; how to distinguish the pre-tax value of proved reserves in concessionary regimes from after-tax reserves under production sharing contracts and the like; how to incorporate forward prices rather than historical averages, and how to report on the value of legal contracts and rights, rather than merely on volumes and well data. StatoilHydro thinks that such attributes would better promote efficiency, competition and capital formation. Unfortunately, the proposed rules fail to some extent to provide the users with this valuable information, while it adds a significant administrative burden in other areas.

App L Initial Regulatory Flexibility Analysis

No comment