1. **Group Management**

100. As noted, the Shell Group is made up of two public parent companies: Royal Dutch and Shell Transport. They remain separate in terms of management and location. Indeed, the parent companies have separate management and boards of directors. This management structure is duplicative, cumbersome and unresponsive to the challenges associated with operating an integrated energy company, and encouraged, permitted and failed to prevent the fraud alleged herein.

101. Shell Transport, which has repeatedly represented in its Annual Reports that it is "committed to the highest standards of integrity and transparency in its governance of the Company," has a board of directors that is comprised of non-executive directors, "at least two Managing Directors of the Company, who [are] also Group Managing Directors," and a Chairman, "who [is] also one of the Managing Directors."

102. Royal Dutch, which also has repeatedly represented in its Annual Reports that it is "committed to upholding the highest standards of integrity and transparency in [its] governance of the Company," is managed by a Supervisory Board and Board of Management. The Supervisory Board is appointed by the General Meeting of Shareholders from the persons nominated by the meeting of holders of priority shares. (Royal Dutch has 1,500 priority shares outstanding, held by members of the Supervisory Board, the members of the Board of Management, and the Royal Dutch Priority Shares Foundation. The Board of the Foundation consists of all the members of the Supervisory Board and the members of the Board of Management.)

103. The Board of Management consists of at least two Managing Directors under the supervision of the Supervisory Board. Managing Directors are appointed by Royal Dutch shareholders and by the Supervisory Board. The Managing Director appointed by the

Supervisory Board serves as President of the Board of Management.

104. The Supervisory Board is responsible for supervising the policies of the Board of Management and the general course of business of Royal Dutch and the Shell Group and further advises the Board of Management.

105. The boards of the parent companies delegate management of the Shell Group to the CMD, which is a committee comprised of senior executives from each of the two public companies. Members of the CMD are known as Group Managing Directors. The CMD considers and develops the Shell Group's business plans and objectives. The CMD is an informal body, with no formal executive authority; the position of chairman is, therefore, also informal.

106. At the beginning of 2002, the members of the CMD were: (1) Watts – Chairman of the CMD from 2001 to 2004, and a Shell Group Managing Director from 1997; (2) van der Veer – now Chief Executive of Shell, was then Vice-Chairman of the CMD; (3) Skinner – who resigned from Shell in September 2003; (4) van de Vijver – responsible for exploration and production, contracting and procurement; (5) Harry Roels – who resigned in June 2002; and (6) Brinded – who succeeded to the CMD following Roels' resignation in July 2002. Boynton joined the CMD in 2003.

107. The CMD reports to a group called the "Conference." The Conference is comprised of all the members of the Supervisory Board and the Board of Management of Royal Dutch and the Directors of Shell Transport. The Conference acts without shareholder accountability.

108. The Conference holds meetings regularly during the year. The purpose of the Conference is to receive information from Group Managing Directors about major developments within the Shell Group and to review and discuss the business and plans of the Shell Group. As

explained in the Shell Group's Annual Reports filed with the SEC on Form 20-F:

> The Conference reviews and discusses: the strategic direction of the businesses and of the Royal Dutch/Shell Group of Companies; the business plans of both the individual businesses and, of the Royal Dutch/Shell Group of Companies as a whole; major or strategic projects and significant capital items; the quarterly and annual financial results of the Royal Dutch/Shell Group of Companies; reports of the Group Audit Committee; appraisals both of the individual businesses and of the Royal Dutch/Shell Group of Companies as a whole; annual or periodic reviews of Group companies' activities within significant countries or regions; governance, business risks and internal control of the Royal Dutch/Shell Group of Companies; a regular programme of insights and briefings on specific aspects of the Royal Dutch/Shell Group of Companies; and any other significant or unusual items on which the Group Managing Directors wish to seek advice.

109. Senior executives of the Shell Group companies also attend meetings of the Conference. Any decision made by the Conference is not legally binding on either Royal Dutch or Shell Transport. The officers of each company must hold separate meetings during which they can make binding, for each parent company, the decisions at which they arrived jointly in the Conference.

110. Royal Dutch and Shell have established three joint committees to assist with the Shell Group's governance responsibilities. All three committees are composed of six members, three of whom are appointed by the Supervisory Board of Royal Dutch from among its members, and three by the Board of Shell Transport from among its members. One of the committees relevant to this action is the GAC.

111. As explained in the Shell Group's Forms 20-F, the GAC "regularly considers the effectiveness of risk management processes and internal controls within the Group and reviews the financial accounts and reports of the Royal Dutch/Shell Group of Companies. The Committee also considers both internal and external audit reports (including the results of the examination of

the Group Financial Statements) and assesses the performance of internal and external audit." As described below, the GAC knowingly or recklessly failed to play a meaningful role in setting priorities or in following up on reserves reporting problems identified by senior executives. The GAC's conduct, or lack thereof, was a direct and material factor in the alleged fraud and its concealment.

B. The Importance of Oil and Gas Reserves

112. In the early days of the oil industry, properties were classified by production rates, in which the practice of oil companies was to produce as much oil as possible, as quickly as possible. The growth of integrated oil companies, with their need to plan sources of supply for refining operations, resulted in the need to measure the ability of a property to produce over a long period of time. This led to the development of methods to quantify original oil-in-place, producible volumes, future productions rates, and other matters that fall under the purview of petroleum engineering. As consideration of economic conditions were added into the analysis (such as discounted cash flow evaluation methods) there existed a need to establish a uniform method of defining "reserves."

113. The term "reserves" generally describes the total volume of future oil production that can be expected to be commercially recovered from a reservoir, assuming that certain physical and economic conditions exist and continue to prevail for however long is required to obtain the production.

114. Reserves can be sub-divided into categories such as proved and unproved; unproved may be further divided into probable and possible. These categories are based on the relative risk of recovery of the reserves in each category. The risk is not, however, in the reserves, but in the likelihood that the expectations for future production and economic conditions

will be met. The risk is accounted for by assigning the anticipated future volume of oil production to a certain category of reserve based upon that risk. The term "reasonable certainty," used by the SEC in Rule 4-10 (see discussion, infra), is intended to express a high degree of confidence that the estimated quantities will be recovered.

115. All integrated oil and gas companies, including foreign companies, trading on U.S. exchanges are subject to oil and gas reporting standards established by the SEC and the Financial Accounting Standards Board ("FASB").

116. Financial Accounting Standard ("FAS") 69 provides the reporting and accounting rules and reporting formats for: (a) proved oil and gas reserve quantities; (b) capitalized costs relating to oil and gas producing activities; (c) costs incurred for property acquisition, exploration, and development activities; (d) results of operations for oil and gas producing activities; and (e) a standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities (it requires future production revenues to be calculated by applying year-end oil and gas prices to year-end reserves, and bases future costs on year-end costs and the assumed continuation of existing economic conditions).

117. Rule 4-10(a) provides the definition of proved reserves for reporting purposes:

> (2) **Proved oil and gas reserves.** Proved oil and gas 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.
>
> * * *
>
> (3) **Proved developed oil and gas reserves.** Proved

developed oil and gas 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.

(4) **Proved undeveloped reserves.** Proved undeveloped oil and gas 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 technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

118. The Shell Group's publicly stated definition of "proved reserves" and "developed proved reserves" – as stated in the Shell Group's Annual Reports filed with the SEC on Form 20-F – is, in all material respects, identical to the SEC's definitions:

Critical Accounting Policies

* * *

Estimation of oil and gas reserves

Oil and gas reserves have been estimated in accordance with industry standards and SEC regulations. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that

> geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
>
> * * *
>
> Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

119. Analysts and investors recognize the importance of reserve reporting in the evaluation of oil and gas companies. As recognized by THE WALL STREET JOURNAL in an article published on January 12, 2004, "reserve growth is a crucial indicator of how well a company is" performing. Reserve reporting is considered "a lifeblood measure of [an oil and gas company's] future prospects." Indeed, as THE WALL STREET JOURNAL recognized two months later, on March 12, 2004, "[r]eserves are a key measure of an oil company's recent performance and longer-term value for investors." If the total volume of the proved reserve declines, the company will be less valuable to investors, which in turn will result in a falling stock price.

120. Although reserve reporting is a crucial metric for investors in evaluating the quality and success of an oil and gas company, it is not the only metric used by analysts and investors to assess the strength – and future prospects – of an energy company. Other important metrics include: (a) Reserve Life, which compares barrels of proved reserves to annual actual production to answer, in terms of years, how long a company's proved reserves will last given the current production level; (b) Reserve Replacement Ratio, which compares additions to proved reserves to production (it puts side-by-side oil newly-claimed to be in the ground to oil taken out of the ground, usually on an annual basis) (a reserve replacement ratio of 100% indicates that a company's proved reserves are being replenished at exactly the rate that the company is extracting/producing oil; a ratio of more than 100% indicates that a company, despite its annual

extraction of oil and gas, is finding more hydrocarbons than it produces, and thus adding to its asset base; and a ratio of less than 100% indicates that a company is depleting its proved reserves); (c) Finding and Development Costs/Barrel, which are the costs of the process that results in the booking of proved reserves and then the extraction and sale of oil or natural gas.

THE GENESIS OF THE FRAUD

A. Economic and Regulatory Conditions Leading Up To The Shell Group's Decision To Overbook Proved Reserves

1. Competitive Pressures and Lack of Organic Growth <u>Create the Need to Overbook Proved Reserves</u>

121. For much of the early 1990s, the Shell Group reigned as the world's largest integrated energy group. By the end of the first half of the 1990s, the Companies came under significant competitive pressure from its key rivals, BPAmoco and ExxonMobil, both of which were building their reserves with discoveries, mergers, and strategic investments.

122. Unlike their competitors, the Companies over-relied on their traditional prowess for finding oil as the engine for growth. As THE WALL STREET JOURNAL observed in an article published on March 12, 2004, new discoveries were becoming harder to find, "as Middle Eastern countries expelled foreign oil companies and fields in the West matured." BPAmoco and ExxonMobil responded by buying up their rivals and selling off poor-performing fields. The Shell Group, however, primarily relied on organic growth through searching for big discoveries, and relied on drilling exploration wells in too many countries and in places where the size of any oil find would not be large enough to make a material difference. Operationally, as reported by LONDON TIMES on March 28, 2004, the Shell Group was "lagging behind competitors in key performance measures instead of just keeping up." Between 1996 and 2000, the Shell Group spent $6 billion per year on finding new reserves. Analysts opined that the figure should have

been higher, closer to $9 billion. As a consequence, the Companies were replacing reserves at a much lower rate than originally represented, and its costs were significantly higher.

123. The Shell Group justified its inaction by arguing that cross-border mergers were messy and often destroyed shareholder value. Instead of creating value through mergers and acquisitions (although the Shell Group did acquire Enterprise in April 2000 for $5.3 billion in equity and $2 billion in debt), Shell sought to create value through cost-cutting, a strategy first implemented in 1998 by Defendant Moody-Stuart. Analysts complained that focusing on cost-cutting diverted the Shell Group's commitment to fund exploration and production when the price of oil began to recover. This strategy cost the Shell Group the opportunity to find millions of barrels of hydrocarbon discoveries, such as the oil fields in the deep waters off Angola, where all of the Shell Group's main competitors have significant investments.

124. The difficulty in finding new reserves translated into higher costs, another key measure for investors. Between 1997 and 2002, Wood Mackenzie, an energy consultancy, estimates that the Shell Group's cost of finding and developing oil was $4.27 a barrel, higher than ExxonMobil's $3.93 and BPAmoco's $3.73.

125. The Shell Group's failure to invest enough in finding new reserves and inability to sustain targeted cost-cutting left managers scurrying for ways to show growth. One internal memorandum noted: "Our reserves replacement performance over the past few years clearly illustrates the emerging problems with our resource base and is becoming a source of competitive disadvantage."

126. In response, according to internal corporate documents and interviews with oil executives and industry analysts identified by the news media, senior management, including the Individual Defendants, embarked on a course of conduct that was designed to manage the Shell

Group's reserve figures much the way non-energy companies manage their earnings – to satisfy investors. This course of conduct was directly contrary to the corporate transparency publicly advocated by Defendant Watts, one of the masterminds of the fraud alleged herein: "It is not surprising trust in business has declined in the wake of a rash of corporate scandals. . . . I think there is every justification for people to question a business climate that allowed those things to happen. . . . We need to be transparent." (From a speech entitled "A Business Approach to Earning Trust in Society," at the KPMG Global Energy Conference, May 2003, quoted in SMARTMONEY June 1, 2004.)

2. The Shell Group Loosens its Reserves Reporting Guidelines

127. Consequently, in 1997, as reported in THE NEW YORK TIMES on March 12, 2004, senior executives instructed the leadership and performance group, known within the Group as "LEAP," to "create value through entrepreneurial management of hydrocarbon resource volumes." The Group created LEAP in the mid-1990s to improve business practices, reduce expenses, and increase income by studying particular issues and consulting experts inside and outside the Group.

128. Pursuant to management's instructions, LEAP sought ways to change the Companies' guidelines with respect to classifying reserves. According to THE NEW YORK TIMES, although other companies implemented similar management programs, industry executives interviewed said that they were unaware of any instances of such a program being used to overhaul a company's accounting guidelines.

129. As the FSA found in its Final Notice to the Companies, dated August 24, 2004 (the "Notice to Take Action"), in September 1997 LEAP issued, and the Companies approved, revised Petroleum Resource Guidance (Volume 1 Resource Classification and Reporting Requirements)

to be used as the basis of reporting proved reserves under SEC rules. In effect, as reported by the LONDON TIMES on March 28, 2004, LEAP proposed that the Shell Group relax the accounting guidelines it used to book reserves.

130. The Group implemented the revised guidelines in four countries for the year ended December 31, 1997. As a consequence, the Group added 145.5 million boe in proved reserves for that year.

131. In 1998, the Group created five Value Creation Teams ("VCTs") to improve EP's profitability. According to the FSA, one VCT was tasked with "creating the maximum value from Shell's hydrocarbon reserves." In a paper dated May 1998 entitled "Creating value through Entrepreneurial Management of Hydrocarbon Resource Values," Group managers recommended, among other things, that the Companies loosen their reserves guidelines. On September 16, 1998, the Companies revised their reserves guidelines, and issued the revised guidance to their operating units.

132. A former Group executive interviewed by THE WALL STREET JOURNAL, as reported in an article published on March 18, 2004, confirmed the foregoing, explaining that the Group loosened the rules to allow gas reserve bookings with only a "reasonable expectation" of an available market.

133. In the Cease and Desist Order, the SEC also confirmed the change in the Companies' guidelines:

> Shell instead revised its guidelines in 1998 to adopt a system under which it maintained its existing probabilistic methods for estimating proved reserves in "immature" fields, but applied more deterministic methods in "mature" fields, directing OUs to increase proved reserves in such fields to equal "expectation" volumes.

134. As the SEC explained, "[a]n oil and gas reserves estimation methodology is

considered 'probabilistic' when the known geological, engineering and economic data are used to generate a range of estimates and their associated probabilities." "An oil and gas reserves estimation methodology is considered 'deterministic' if a single best estimate of reserves is made based on known geological, engineering and economic data."

135. The Companies used the term "expectation reserves" to mean "the most likely estimate of hydrocarbon volumes remaining to be recovered from a project that is technically and commercially mature, or from a producing asset." As noted by the SEC, "[i]f probabilistic techniques are used in reserve estimation, the expectation reserves are the probability weighted average of all possible outcomes (common referred to as the 'P50' outcome). If deterministic techniques are used, expectation reserves correspond to most likely estimate of future recovery." As a general matter, the Shell Group classified a field as "mature" under the revised guidelines if total production was greater than 30% of expectation reserves.

136. This practice deviated from the Shell Group's early 1990s practice, as set forth in the Companies' reserve-booking guidelines (a two-volume document updated each year), that permitted executives to book proved reserves only if the Shell Group had signed a sales contract for the oil or gas.

137. As revealed in the news media, the GAC Report, the Notice to Take Action, and the Cease and Desist Order, the new guidelines significantly inflated the Shell Group's reserves by enabling executives to book proved reserves well before making significant investments to get the oil and gas out of the ground. For example, as noted by the SEC, "nearly 40% of the total proved reserves Shell added in 1998 resulted from this guideline revision." For the two years ended December 31, 1999, the Shell Group's revised guidelines resulted in an overstatement of the Group's proved reserves of 940 million boe. For the period 1998 through 2001, the SEC

found that the change in guidelines caused the Shell Group to add more than 1.2 billion boe to reported proved reserves. These new guidelines were contrary to the SEC definition of proved reserves, which, as alleged herein, requires, among other things, data indicating there is a "reasonable certainty" that oil or natural gas can be recovered through existing wells and equipment, and/or a plan of development has been approved.

138. Numerous former employees who had first-hand knowledge of these issues while employed by the Companies have emphasized that the Companies made no effort to apprise employees in the field of the SEC's requirements for classifying reserves as proved. CS 2 stated that the Companies had internal rule books dictating how reserves were to be reported, but that those books contained no mention of SEC guidelines. CS 3, who provided reserves data to The Hague for various fields in Nigeria, stated that CS 3 never saw any material that described SEC guidelines for reporting proved reserves. CS 4, whose responsibilities included not only estimating reserves, but also training engineers about how to estimate reserves, stated that CS 4 had never seen the SEC guidelines until he/she read about them in newspaper accounts earlier this year. Similarly, CS 5 stated that he/she never used SEC guidelines in calculating reserves, and that few technical people at the Companies would have been aware of those guidelines.

139. The former Shell executive interviewed by THE WALL STREET JOURNAL (as reported in the article of March 18, 2004) also said that the Companies amended their guidelines again at the end of 2001 to warn that gas from "major" projects should not be booked as reserves until agreements had been signed concerning the Shell Group's commitment to invest money in the project. However, even this amendment did not go far enough to comply with SEC and accounting rules. This was confirmed by the SEC in the complaint it filed in connection with the Cease and Desist Order: "Before September 2003, with respect to frontier developments [, such

as Gorgon,] Shell's guidelines required neither a currently existing market for a field's hydrocarbons nor a commitment by Shell to develop the field or the infrastructure necessary to bring the hydrocarbons to market." Only with the 2003 guideline revisions did the Companies require, for the first time, certainty of an existing market and a "Final Investment Decision" on significant projects before reserves associated with the project could be classified as proved.

140. According to an internal report dated December 8, 2003 (a 42-page report to senior Group executives describing significant overstatement of the Companies' proved oil and gas reserves by 2.1 billion to 3.6 billion boe) (the "December 8th Report"), the original amendments "corrected the group's under-reporting of mature reserve fields relative to competitors, [b]ut with the benefit of hindsight it left the group vulnerable to net over-reporting of immature field reserves, brought about, for example, by registering reserves well in advance of the commitment to develop and including reserves outside the proven area as it would be defined by the S.E.C."

141. Taking advantage of the changes, the Group Defendants were able to reverse the trend of declining reserves – and more important, they were able to report that the Shell Group was replacing reserves far faster than it was producing them. According to a confidential internal review code-named Project Rockford (which led to the December 8th Report), the changes LEAP recommended allowed the Group to increase its oil and gas reserves not by discovering major new sources, but by changing its accounting to add reserves it was uncertain could ever be produced.

142. Thus, as reported in THE LONDON TIMES on March 22, 2004, Watts, then the senior executive in charge of the EP unit, was able to tell 600 Group executives at a conference in the Dutch city of Maastricht in June 1998 of the success of a special management program that had recently addressed a fundamental problem at the Companies – that the Companies were

producing oil and gas faster than they were finding new reserves. At that time, Watts did not disclose that the problem of declining reserves was resolved by relaxing the Companies' reserves reporting guidelines in violation of SEC Rule 4-10.

3. **The SEC Increases Its Scrutiny of the Industry's Reserves Reporting**

143. By 1999, concerns were rising over a push by U.S. oil companies into overseas projects and a boom in joint ventures, trends that made it more difficult to get a clear picture of reserves. Consequently, the SEC began to intensify its scrutiny of oil company reserves, in particular with respect to the manner in which oil companies calculated reserves in deepwater fields, such as in the Gulf of Mexico. According to the Shell Group, less than 10% of the reclassified reserves are related to the SEC's Gulf of Mexico review.

144. According to a March 12, 2004 article published in THE WALL STREET JOURNAL, the SEC hired two engineers dedicated to reviewing reserve estimates for oil and gas companies, Jim Murphy and Ron Winfrey. Murphy and Winfrey soon put the industry under greater scrutiny. In 2000 and 2001, the SEC issued guidelines requiring companies to have investment commitments and other supporting evidence to show why they believed their oil and gas fields would be developed under prevailing financial, political, and technical factors. For example, on March 31, 2001, the SEC issued the guidance on the application of Rule 4-10. Specifically, the SEC:

- emphasized the conservatism underlying the definition of proved reserves;
- observed that "economic uncertainty such as the lack of a market (e.g. stranded hydrocarbons) . . . can also prevent reserves from being classified as proved";
- specifically advised that, in "developing frontier areas . . . issuers must demonstrate that there reasonable certainty that a market exists for the hydrocarbons and that an economic method of extracting, treating and transporting them to market exists or is feasible and is likely to exist in

the near future . . . significant lack of progress on the development of such reserves may be evidence of a lack of commitment. Affirmation of this commitment may take the form of signed sales contracts for the products"; and

- with respect to hydrocarbon volumes whose production depends on the extension of government permits or licenses, indicated that automatic renewal of such permits or licenses "cannot be expected . . . unless there is a long and clear track record which supports the conclusion that such approval and renewals are a matter of course."

145. The GAC Report notes that, as a general matter, "[b]eginning in 2001, recognition of the strictures of SEC rules, in place since 1978, increased within the Company, in part due to the publication on the SEC website of SEC guidance regarding the importance of investment commitments and other indicia of 'reasonable certainty,' with a growing recognition that the Company's reserve numbers were not in full compliance with these rules."

146. In letters to oil companies in 2002, the SEC chastised companies for not obeying reserves rules, demanding explanations of how calculations were made. In industry forums, SEC engineers cited as "red flags" reserve calculations in countries where the government had not approved the project.

147. In 2002, as SEC officials were beginning to offer tougher interpretations of the accounting rules for reserves, executives at the Shell Group developed a Potential Reserves Exposure Catalogue, which listed the major concerns of the current inventory. Modest reductions in the volume of booked reserves were made, but most booked reserves were retained. According to the December 8th Report, "The view was taken that the exposures should indeed be highlighted and addressed as a matter of priority, but that no corrective action was warranted in the meantime in relation to external disclosures." This course of action did not comport with SEC rules. Under Rule 4-10, when previously reported proved reserves no longer satisfy the requirements of the

rule, they can no longer be included in proved reserves disclosures. The Companies' guidelines did not require the Group to de-book the reserves that no longer qualified as proved under the SEC rules. Instead, as noted in the SEC complaint, "the guidelines urged Shell personnel to 'exert caution' in de-booking reserves to 'minimize fluctuations [in proved reserves] over time.'"

148. The December 8th Report also indicated that there were financial incentives for executives to overstate reserves: "Through the linkage of proven reserves additions to business and individual score cards, it is possible that situations occurred in which staff involved with reserves estimation were subjected to pressure to propose proved reserves changes that might not have been fully compliant." As reported in THE WALL STREET JOURNAL EUROPE on July 15, 2004, the Companies' Group Reserves Auditor ("GRA"), Anton Barendregt ("Barendregt") – the lone, part-time, former Shell employee who was responsible for auditing the Group's proved reserves worldwide – "prominently flagged" in two reports written in January 2002 and 2003 (both of which were sent to senior managers and the accounting defendants) that the Companies' "scorecard" bonus system encouraged the inflation of reserves bookings. In the January 2003 warning, Barendregt devoted a lengthy section to the scorecard bonus system. In that memorandum, Barendregt wrote that senior managers in the EP division rejected doing away with reserves-related bonuses. That decision did not sit well with Barendregt, who wrote, "it is the auditor's firmly held belief that the reserves-addition targets in these score cards present a potential threat to the integrity of the Group's reserves estimates." As Colin Allcard, a former senior manager in Shell Transport's Ethiopian oil products division, was quoted as saying in a March 12, 2004 article in THE NEW YORK TIMES, "They set clearly defined targets, and created motivational schemes. Your performance was measured and rewarded."

B. Defendants' Knowledge of the Group's Overbookings

149. On January 31, 2000, Group managers made a presentation that showed an RRR of 37% for the year ended December 31, 1999. As noted by the FSA, "This RRR figure was robustly rejected and on 11 April 2000 Shell announced an RRR for 1999 of 56%." According to the FSA, the presentation also highlighted concerns in Nigeria that a substantial portion of the SPDC's reported proved reserves (in excess of 600 million boe) were vulnerable as non-compliant with SEC rules – these reserves were "constrained by license expiry and depended on unrealistic production forecasts that appeared to have been 'reverse engineered' solely to support the reserve figures." (Emphasis added.) The presentation also cautioned that proved reserves could not be booked in Gorgon because of "limited market availability and already large uncommitted proved gas reserves." Significantly, the presentation noted that reported proved reserves in Gorgon had been a point of contention for the previous two years with external auditors.

150. In June 2000, Shell Group planners made an internal presentation to senior managers (believed to be the "executive committee" of the EP unit, as reported by THE WALL STREET JOURNAL on April 1, 2004), warning that the Companies risked disappointing financial markets with overly optimistic assumptions about exploration and production projects around the world.

151. In the introductory pages of the presentation – under the heading "The Bad News" – the planners warned that senior executives "run the risk of initiating an over-promise, under-delivery cycle." At the time, Shell Transport was publicly portraying the upstream business as poised for continued growth. In a December 2000 slideshow for investors presented by Watts, the Companies said their upstream business was "delivering on promises," including a commitment

to boost annual oil and natural gas output by 5% between 2000 to 2005. But internally, as set forth in the June 2000 presentation, Group planners had already warned senior managers about significant reserve calculation problems. In one page of the June 2000 document – titled "Exploration: Overstated Delivery?" – Group analysts wrote that internal estimates for initial oil production at a number of projects are "very optimistic and unrelated to historical performances." The presentation went on to cite a number of new projects with "possibly overstated value promises."

152. The Group planners questioned whether the Companies could deliver on their production-growth targets as output from existing fields was decreasing by 10% each year. According to the June 2000 presentation, that decline came at the same time that planners raised questions about how funds were being allocated between exploration and production projects. The June 2000 presentation concluded, "Growth in production is a major challenge."

153. As the Shell Group continued to report inflated proved reserves, senior Shell Group executives, including Watts and van de Vijver, argued over how to manage reserves to conceal the evidence that the Shell Group had been overstating its reported oil and natural gas proved reserves for years. The GAC Report notes that some of the communications between Watts and van de Vijver were conducted through private e-mails and meetings, as well as CMD meetings. Consequently, "other executives and employees had, over time, varying degrees of exposure to the debate [between Van de Vijver and Watts] and, in various strata of management at Shell's Central Offices and in the field, involvement in the operations that were the subject of the bookings."

154. According to the GAC Report, Watts and van de Vijver spoke, often heatedly, as early as 2001 about the EP unit's ability to meet internal targets and/or public promises to

investors, shareholders, and market analysts, particularly those relating to reserves. Van de Vijver described this dialogue in a March 22, 2004 letter:

> Soon after coming to office as head of EP in June 2001, I observed that the health of the EP business was not as robust as the Company-determined performance targets set under the former EP CEO. In fact, EP was in a far worse state in mid 2001 than was ever portrayed by my predecessor to senior management or the Conference.

154a. Indeed, CW 6 stated that, even before van de Vijver became the CEO of EP in 2001, CW 6 attended high level meetings with senior officers and directors of SEPCo and the Companies, including defendants van de Vijver and Miller, in Houston. CW 6 stated that, at meetings in 2000 and 2001, van de Vijver discussed many of the problems that should have precluded the Companies from booking proved reserves in Nigeria. See ¶¶ 206-46, infra.

155. According to the GAC Report, van de Vijver "consistently pressed the position that reserves booked during Sir Philip's term were aggressive or premature, non-compliant with Shell Guidelines for booking and, implicitly, SEC rules." The improper booking of the reserves had reinforced a false perception in the market, but was viewed "primarily as a serious and immediate business question but not, equally, as a regulatory and disclosure failing."

156. In October 2001, the January 17, 2000 presentation was again called to the attention of Shell Group managers. As noted by the FSA, the Companies did not take any action to address the issues raised by the presentation.

157. Van de Vijver was not the only person within the Shell Group to warn of overstated reserves. As reported in The WALL STREET JOURNAL EUROPE on July 15, 2004, Barendregt, warned in a January 2002 memorandum, marked "confidential," that a portion of 2001 mature reserves (approximately 1,250 million boe) was at risk of being overstated. He also raised questions about the integrity of Shell's overall reserves-reporting system. Barendregt further

warned that the Shell Group's guidelines for booking reserves were not in compliance with SEC guidelines in all cases. Barendregt circulated this memorandum to senior Shell Group executives (in the EP unit) and to KPMG and PwC. As noted in the article, "three people familiar with the situation" confirmed that KPMG and PwC received the memorandum.

158. The GAC Report reveals that senior executives repeatedly generated and circulated reports among other senior Shell Group executives warning that the Companies' internal guidelines for booking reserves were inconsistent with current SEC guidelines. In a Note for Information summarizing the Shell Group's reserves position at December 31, 2001, which van de Vijver forwarded to the CMD on February 11, 2002, van de Vijver warned that proved reserve exposures were as high as 2.3 billion boe because of non-compliance with SEC guidelines:

> **Exposures**
>
> **Securities and Exchange Commission (SEC) Alignment**
> Recently the SEC issued clarifications that make it apparent that the Group guidelines for booking Proved Reserves are no longer fully aligned with the SEC rules. This may expose some 1,000 mln boe of legacy reserves bookings (*e.g.* Gorgon, Ormen Lange, Angola and Waddenzee) where potential environmental, political or commercial showstoppers exist.
>
> **End of License**
> In Oman PDO, Abu Dhabi and Nigeria SPDC (18% of EP's current production) no further proved reserves can be booked since it is no longer reasonably certain that the proved reserves will be produced within license. The overall exposure should the OU business plans not transpire is 1,300 mln boe. Work has begun to address this important issue.

159. According to the GAC Report, "[t]he Note raised issues of sufficient concern to [Watts] that he required . . . a further presentation be made to [the] CMD."

160. On February 20, 2002, EP managers circulated the EP Business Appraisal for 2001, which was presented at a meeting held on February 25 and 26, 2002. According to the

FSA, "[b]oth the 'Main Issues' section and the main body of the Appraisal stated that the SEC's guidance made it clear that the approach advocated by Shell guidelines was, in many cases, too aggressive and would be likely to affect future bookings in new fields such as Nigeria and possibly existing bookings representing some 1,000 million boe." The FSA also noted that the "Appraisal also referred to reserves which could no longer be booked because of license expiry issues and production limitations amounting to an additional 1,000 million boe."

161. Notwithstanding the foregoing, on May 28, 2002, in an e-mail to van de Vijver, Watts directed van de Vijver to leave "no stone unturned" to achieve a 100% RRR for 2002, a result inconsistent with significant debooking:

> You will be bringing the issue to CMD shortly. I do hope that this review will include consideration of all ways and means of achieving more than 100% in 2002 – to mix metaphors . . . considering the whole spectrum of possibilities and leaving no stone unturned.

162. CS 5 stated that Watts put extremely high demands on the EP engineers to find more reserves. "It was sent down the line as a directive." According to CS 5, the targets Watts set were not technically realistic, but were financially attractive.

163. Shortly thereafter, on July 22, 2002, a second presentation was made to the CMD in a Note for Discussion submitted by van de Vijver. The Note identified oil and gas reserves that were "aggressive[ly]" booked, notably Gorgon and Nigeria. The Note also observed that without the Gorgon and Nigeria bookings, "total proved RRR over the past 10 years would be reduced from 102% to 88%."

164. As the GAC Report concluded, this presentation was part of a plan to conceal the truth by "managing" the inflated reserve problem in hopes that external events would, over time, remedy the problem:

> it is an example of a series of documents which suggest that EP management's plan was to 'manage' the totality of the reserve position over time, in hopes that problematic reserve bookings could be rendered immaterial by project maturation, license extensions, exploration successes and/or strategic activity. Simply put, it is illustrative of a strategy 'to play for time' in the hope that intervening helpful developments would justify, or mitigate, the existing reserve exposures.

165. Internal documents reveal that it was understood that the Companies did not have the luxury of time to manage reserves. For example, the minutes of the July 2002 CMD meeting establish that it was recognized that delay in debooking could not be continued indefinitely:

> It is considered unlikely that potential over-bookings would need to be de-booked in the short-term, but reserves that are exposed to project risk or licence expiry cannot remain on the books indefinitely if little progress is made to convert them to production in a timely manner.

166. On September 2, 2002, van de Vijver submitted a further note to the CMD (with a copy to Defendant Boynton) describing the "dilemmas" faced by the EP unit in "playing for time"/"managing reserves":

> Given the external visibility of our issues (lean organic development portfolio funnel, RRR low, F&D unit costs rising), the market can only be 'fooled' if 1) credibility of the company is high, 2) medium and long-term portfolio refreshment is real and/or 3) positive trends can be shown on key indicators.
>
> Unfortunately . . .:
>
> - We are struggling on all key criteria ("caught in the box").
>
> . . .
>
> The immediate risk that we are facing is on the "negative spiral" of our boxed situation:
>
> . . .
>
> - RRR remains below 100% mainly due to aggressive booking in 1997-2000.

167. In a confidential personal Note to File that he wrote in September, 2002, van de Vijver acknowledged that he and other members of the EP unit knew that the Shell Group's public representations concerning reserves were inaccurate:

> During the last 1.5 years the technical competence and overall integrity of the EP business within Shell has been questioned both internally and externally, most prominently through lowering of the production growth target in August/September 2001 and due to a deteriorating proved reserves replacement ratio. Providing credible explanations for these issues proved near impossible given the disconnects between external promises/expectations and the reality of the state of the business.
>
> . . .
>
> Bottomline was that both reserves replacement and production growth were inflated:
>
> > - Aggressive/premature reserves bookings provided impression of higher growth rate than realistically possible.
>
> . . .
>
> The concerns around the "caught in the box" dilemma and stretch in the EP business plan have been flagged at the highest level in the company, but obviously "transmitted" in a careful fashion as not to compromise/undermine the previous leadership. The severity and magnitude of the EP legacy issues may therefore not have been fully appreciated.

168. Also in September 2002, according to the FSA, the Shell Group created and implemented a reserves exposure catalogue "to ensure a system of awareness and control of the proved reserves inventory." The catalogue detailed seven potential exposures, totaling 905 million boe, of which Gorgon was the largest, with 506 million boe. The notes to the catalogue indicate that the reserves in some operating units would be at risk if production rate increases did not materialize. The notes further stated that certain bookings were threatened by clarifications to the SEC's rules by the Commission, requiring conservatism in the classification of proved reserves.

169. Consistent with the foregoing, on October 22, 2002, van de Vijver wrote to Watts that the Shell Group had been in violation of the U.S. securities laws:

> I must admit that I become sick and tired about arguing about the hard facts and also cannot perform miracles given where we are today. [Emphasis added.]
>
> If I was interpreting the disclosure requirements literally (Sorbanes [sic]-Oxley Act etc) we would have a real problem.

170. On November 15, 2002, van de Vijver circulated a brief outline of business plan issues to members of his EP staff. In the document, van de Vijver concedes that the plan as submitted reflected the concealment of the truth about the Shell Group's reserves:

> We finalized our plan submission and could easily leave the impression that everything is fine.
>
> . . .
>
> The reality is however that we would not have submitted this plan if we
>
> > 1) were not trying to protect the Group reputation externally (promises made) and
> >
> > 2) could have been honest about past failures (business focus w.r.t. aspired portfolio, disconnects with reality, poor performance management, reserves manipulation).

171. On January 31, 2003, Barendregt wrote another "confidential" memorandum that he circulated to senior Shell Group executives (in the EP unit), as well as to KPMG and PwC. As with his January 2002 memorandum, KPMG and PwC received the memorandum. The January 2003 memorandum reviewed the prior year's reserves estimates. Like the January 2002 memorandum, Barendregt's January 2003 memorandum warned that the Shell Group's guidelines for booking reserves did not comport with SEC guidelines in all instances and raised questions about the integrity of the Companies' overall reserves-reporting system. Moreover, according to the FSA, Barendregt "considered areas where there was an issue with product license

constraints." In Nigeria, for example, Barendregt concluded that the Group had overstated proved reserves by approximately 20%, or 600 million boe. In Oman, Barendregt concluded that Petroleum Development Oman ("PDO") had overstated proved reserves by approximately 65 million boe. According to FSA, "this overstatement was in addition to the potential exposure shown in the exposure catalogue of 905 million boe."

172. As noted above, Barendregt also dedicated a significant portion of the 2003 warning to the Shell Group's scorecard bonus system and the threat of that system "to the integrity of the Group's reserves estimates."

173. The GAC Report, the Cease and Desist Order, and the Notice to Take Action provide additional instances in which Defendants were informed of the overbooking of proved reserves and in which Watts and van de Vijver specifically acknowledge their knowledge of the reserves problem and Defendants' false public statements with respect thereto. On February 28, 2003, van de Vijver sent Watts a copy of a February 23, 2003 e-mail in which van de Vijver stated to his EP staff:

> We know we have been walking a fine line recently on external Messages. . . . Promising that future reserves additions are expected in 2003 . . . whilst we know that there is some real uncertainty around this. . . . [W]e know our ongoing exposures on Oman/Nigeria reserves and on early bookings, notably Gorgon and Ormen Lange.

174. On July 17, 2003, managers circulated a memorandum that was discussed on July 22, 2003. According to the FSA, the memorandum included "an updated exposure catalogue and stated that of Shell's 19,350 million boe proved reserves '*some 1040 million boe (5%) is considered to be potentially at risk.*'" (Orig'l emphasis.) The note concluded that, "at this stage, no action in relation to entries in the [Proved Reserves Exposure] Catalogue is recommended . . . . It should be noted that the total potential exposure listed in Appendix C is broadly offset by the

potential to include gas fuel and flare volumes in external reserves disclosures." The Proved Reserves Exposure Catalogue in Appendix C to the Note quantifies exposures at approximately 1,000 million boe and "threats" at approximately 1,600 million boe, for a total of approximately 2,600 million boe potentially at risk of non-compliance with Rule 4-10.

175. On August 25, 2003, van de Vijver directed a draft of his Mid-year 2003 Review Summary to Watts, complaining that: "The single largest issue facing EP is the shrinking opportunity portfolio exacerbated by too aggressive reserves bookings in the past . . . ."

176. The following day, the GAC received a memorandum that addressed possible areas of non-compliance with Rule 4-10. According to the FSA, "[t]he GAC was advised that '"*much, if not all, of the potential exposure arising from interpretation of the factors . . . is offset by Shell's practice of not disclosing reserves in relation to gas production that is consumed on site as fuel or (incidental) flaring and venting.*'" (Orig'l emphasis.) The memorandum included as attachments the proved reserves exposure catalogue, which identified "potential exposures" totaling 1,000 million boe and "threats" of 1,600 million boe.

177. Before the circulation of this memorandum, the potential for booking reserves including fuel and flare was discussed among EP's technical staff. In a note dated July 9, 2003, technicians stated that changing the Companies' policy to include 1,000 million boe should not be considered lightly and that, were the Companies to do so, a detailed explanation would have to be provided as there was a risk that

> the gain would be seen purely as a paper exercise: many analysts have concluded that reserves replacement is the key challenge facing Shell over the next few years and they might react negatively to this one-off adjustment to the figures. Moreover, this difference in reporting practice . . . provides an offset to other elements of existing proved reserves inventory that could be viewed as being potentially at risk . . . . [T]he potential exposure that they represent is also of the order of 1,000 million boe.

178. On November 9, 2003, after receiving what he considered an unfairly critical performance review from Watts, van de Vijver e-mailed Watts, complaining that he was "becoming sick and tired about lying about the extent of our reserves issues and the downward revisions that need to be done because of far too aggressive/optimistic bookings."

179. On November 8, 2003, the day before van de Vijver sent his e-mail to Watts complaining that he was tired of lying about proved reserves, van de Vijver wrote an e-mail to a colleague about the Group's aggressive reserves bookings and the impact on the RRR and the price of the Companies' stock:

> As you know 2003 RRR is the most important share price influencer also as expectations are high and they do not know that we are still paying for aggressive reserves bookings [including thos[e] that have not reached FID yet!!] in the past!

180. Van de Vijver, who was aware RRR was a key performance indicator, had participated in stock analysts' presentations in which the issue of proved reserves and RRR were a focus.

181. At the end of November 2003, a presentation was prepared for a meeting of the Conference, which was scheduled for December 3, 2003. According to the FSA, a draft of the presentation was distributed to some members of the Shell Group's senior staff. Regarding Oman and Nigeria, the draft presentation stated: "the total volume not in compliance with SEC guidelines in the proved reserves filing in the 20-F as per 31/12/02 has become significant (2.1 bln boe or 11% of the Group's total proved reserves)."

182. According to the GAC Report, in December 2002 and November 2003, van de Vijver considered the idea of a comprehensive debooking of all known exposed reserves. In December 2002, van de Vijver asked the Group Reserves Coordinator ("GRC") for an analysis of the effect of a debooking of all questionable reserves. In late November 2003, van de Vijver

stated in a message to the GRC, "I would prefer to re-state our 1/1/03 reserves and de-book all remaining legacies to allow for a clean start." At about the same time, however, van de Vijver delivered an encouraging message on planning goals to all senior EP executives in which he warned: "One final word on 2003. It would be an enormous blow to the Group's credibility with the Market if we do not deliver on RRR this year."

183. In a December 2, 2003 memorandum prepared by the EP staff, entitled "Script for Walter [van de Vijver] on the proved reserves position," the assumption was made that approximately 2.3 billion boe of proved reserves were non-compliant (approximately the same amount identified as exposed on February 11, 2002), and that this was material to the market. Given these facts, the script called for immediate disclosure of the truth:

> If and from the time onwards that it is accepted or acknowledged by the management of the issuers (Royal Dutch and STT), that, when applying the SEC rules, the 2002 proved reserves as reported in the Form 20-F are materially wrong, the issuers are under a legal obligation to disclose that information to all investors at the same time and without delay. Not to disclose it would constitute a violation of US securities law and the multiple listing requirements. It would also increase any potential exposure to liability within and outside the US. Note that the reserves information also appears in the non 20-F Annual Reports.
>
> Disclosure cannot await the next Form 20-F appearing in April, 2004.

184. On the same day that the "Script" was provided to van de Vijver, he immediately e-mailed one of its authors, the EP unit's head of finance, Frank Coopman, demanding that the e-mail be destroyed: "This is absolute dynamite, not at all what I expected and needs to be destroyed."

C. The Geographic Areas in which Reserves Were Reclassified

185. Of the total proved reserves restated, 89% (3,992 million boe) was attributable to Group companies, and the remainder was attributable to associated companies. Twelve percent of the total had been in the proved developed reserves category, and 88% had been categorized as proved undeveloped reserves. Various properties in Nigeria accounted for 36% of the restated volume, the Gorgon field and other properties in Australia accounted for 17%, and the effect of applying year-end pricing accounted for 7% of the total. Additional adjustments include properties in Kazakhstan (8%), the rest of the Middle East (9%), the rest of Asia Pacific (10%), and Europe (9%). After giving effect to the reserves restatement, the proportion of total proved reserves that was accounted for as proved developed reserves at that date increased from 46%, as originally stated, to 56%.

186. For purposes of this Complaint, Lead Plaintiff will address four of the more significant geographic areas in which reserves needed to be reclassified: Australia, Nigeria, Oman, and Norway.

1. Australia (Gorgon)

187. As of December 31, 1997, when Watts was head of EP, the Companies booked as proved approximately 557 million boe of natural gas relating to a single source: the Gorgon fields, which are undeveloped frontier gas fields located 70 miles off the northwestern coast of Western Australia. This amount represents more than 12% of the Companies' total overbooked reserves.

188. To disguise the improper booking, the Companies recorded the reserves not as "new discoveries," which garner more attention from auditors and investors and could have been challenged more easily internally, but instead as "revisions." The "revisions" category, however,

is intended for subsequent adjustments to previously reported reserves, due either to a better understanding of the field or to new technology. It is not intended for reserves that have never before been recorded as proved. According to an analyst with Lehman Brothers, listing Gorgon as a revision "is why it is not really visible to outsiders." Publicly, van de Vijver later portrayed the misclassification as a mistake and an "embarrassment," claiming it was the result of a miscommunication with Shell Australia.

189. Although the Companies now acknowledge that these reserves should not have been recorded as proved at all, whether as revisions or new discoveries, they have also contended that the booking was based upon letters of intent for gas sales and internal-development timetables that ultimately failed. This point was confirmed by the SEC in the Cease and Desist Order: "At that time, Shell did not have a contract to sell Gorgon gas, had no firm development plan and had not made a Final Investment Decision." According to the GAC, the Companies' guidelines at the time allowed proved reserves based on an "expectation of availability of markets," and, for a brief period, commercial expectations for Gorgon arguably met this loose requirement. Analysts, however, have rejected this explanation. Said one analyst quoted in the LONDON TIMES on January 10, 2004, "[e]veryone has letters of intent; it just means they are willing to discuss terms."

190. Moreover, as the GAC Report concedes, "From its inception, the Gorgon 'proved' reserves did not meet the overriding SEC standard of 'reasonable certainty.'" As described below, the history of the Gorgon fields bears this out: the Gorgon reserves unambiguously failed to meet the SEC's "reasonable certainty" standard for proved reserves when they were booked (despite the purported existence of letters of intent). Indeed, they fail to meet that standard even today, more than six years later. To date, neither of the Companies' joint venturers in developing

the Gorgon fields, ChevronTexaco and ExxonMobil, has booked a single cubic foot of Gorgon natural gas as proved – even though ChevronTexaco has already lined up certain customers. Reportedly, ChevronTexaco executives are angry with the Companies for declaring Gorgon gas "commercial" ahead of its partners.

191. According to the website of the Gorgon Venture (defined below) (http://www.gorgon.com.au), the Gorgon area contains certified gas reserves of 12.9 trillion cubic feet, and includes five separate fields: West Tryal Rocks, discovered in 1973; Spar, discovered in 1976; Gorgon, discovered in 1980; Chrysaor, discovered in 1994; and Dionysus, discovered in 1996. Gorgon is the largest, with 12 trillion cubic feet of gas. A broader area, known as the Greater Gorgon reserves, currently represents over 40 trillion cubic feet of gas.

192. Of the three companies participating in the unincorporated joint venture to develop the Gorgon fields (the "Gorgon Venture" or the "Venture"), ChevronTexaco has the largest stake, at 57.1%, and is the operator of the Gorgon fields. The Companies have the next largest interest, at 28.6%, and ExxonMobil has a 14.3% interest.

193. Over a twenty-year period beginning in the early 1980s, the three participants in the Venture spent more than $800 million on exploration, development, and marketing to prepare the Gorgon area for eventual development. In the late 1990s, they determined that the gas processing facility needed for the success of the Venture could not economically and competitively be placed on the Australian mainland, but would have to be built on Barrow Island, a Class A Nature Reserve located some 40 miles east of the Gorgon fields. Thus began a development project that is currently projected to be phased-in over three to fifteen years. As described below, no gas is expected to be recovered and processed before late 2008 – if then – almost eleven years after the Companies booked over 557 million boe of proved gas.

194. In early 2002, the state of Western Australia concluded that a strategic level evaluation of the proposed Gorgon Venture was required for it to make an informed decision about whether to provide in-principle approval for the restricted use of Barrow Island for a gas processing facility. This review was to determine whether the proposed development could generate economic and social benefits, provide net conservation benefits, and mitigate potential on-site impacts. The evaluation consisted of an Environmental, Social and Economic ("ESE") Review that was submitted for state government consideration in February 2003.

195. On September 8, 2003, Western Australia granted in-principle approval for the restricted use of Barrow Island, taking into account the ESE Review, public comment, and the formal advice of the state Environmental Protection Authority, the state Department of Industry and Resources, and the state Conservation Commission. Because this was merely a strategic review, however, in-principle approval did not constitute or imply environmental acceptance of the proposal. Hence, formal environmental assessment under relevant state (of Western Australia) and Commonwealth (of Australia) environmental legislation is still required. That process is ongoing, and environmentalists have vowed to fight approval of the project. According to Chris Tallentire, director of the Western Australia Conservation Council: "Conservationists across Australia are going to be doing all we can to make sure that the proposal doesn't go ahead. It would be quite wrong for any company to say that the gas reserves in the Gorgon field are bookable or in the pocket."

196. Numerous documents on the Gorgon Venture website underscore the multiple contingencies to be resolved and tasks to be accomplished before natural gas can be collected from the Gorgon fields and processed on Barrow Island. As Paul Oen, the team leader of the Gorgon Venture (and a ChevronTexaco employee), stated in a presentation on November 21,

2003: "I . . . need to stress today that while much has been achieved, there is still a lot of hard work and effort required to make this development happen." Oen emphasized the technical obstacles presented by the Venture, resulting from the fact that the gas is "remote," "in deep water," "high in carbon dioxide," and "low in liquids." Oen also emphasized that the Venture had to progress along three tracks simultaneously: "Marketing – which involves signing up customers to underpin the project; Engineering – to firm up the cost and design of the project; and Approvals – to obtain government and investor approvals for the project." Oen underscored that these three tracks would take time: "We're targeting a market window of 2008 to 2010 . . . to launch the Gorgon project. And we're aiming to have the project ready to produce as early as possible within that window."

197. Each of these tracks is enormously complex. The environmental impact assessment currently being undertaken, for example, is far more burdensome than the ESE Review already completed. It differs in the level of detail required, the scope of field investigations and modeling required, and the need for a comprehensive management framework. The assessment will include consideration of environmental, social, and economic factors, and will consider the level of risk posed to the community and the environment, and provide evidence of whether the risk can be managed to an acceptably low level.

198. The assessment will require the participants in the venture to undertake numerous studies, including: (a) a literature review of past studies; (b) field surveys and sampling to describe various aspects of the terrestrial and marine biophysical environments, and to assess the potential impact of the development on key environmental factors; (c) an assessment of potential impacts associated with dredging, and dumping of dredge material; (d) modeling studies to predict the behavior and potential impacts of emissions and spills; (e) the collection of baseline

data for the ongoing monitoring of environmental parameters; and (f) a description of socio-economic environment, and assessment of the potential benefits and impacts.

199. The process will culminate in separate decisions by the Commonwealth Minister for the Environment and Heritage and the Western Australian Minister for Environment, both of whom must determine whether the development can proceed, and, if so, under what conditions.

200. In addition to environmental approvals, the joint venturers must secure pipeline and gas plant approvals under various state and Commonwealth statutes, including the Explosives and Dangerous Goods Act of 1961 (state), the Petroleum Act of 1967 (state), the Petroleum Pipelines Act of 1969 (state), the Petroleum (Submerged Lands) Act of 1967 (Commonwealth), the Petroleum (Submerged Lands) Act of 1982 (state), and the Petroleum (Submerged Lands) (Management of Environment) Regulations of 1999 (Commonwealth).

201. Assuming the Venture secures the various necessary approvals, the technical aspects of the project are daunting and will require years of work. Specifically, according to the Guidelines for an Environmental Impact Statement and Environmental Scoping Document for an Environmental Review and Management Programme for the Proposed Gorgon Development, dated April 8, 2004, the proposed development comprises a number of distinct components:

- A subsea gathering system – at water depths on the order of 200 meters;
- Offshore infrastructure – for the production and transport of gas from the Gorgon area gas fields to Barrow Island, forty miles away;
- Onshore pipelines;
- A gas processing facility – LNG processing plant and associated infrastructure on Barrow Island;
- A port facility – materials offloading facility and LNG loadout facilities on the east coast of Barrow Island;