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UNITED STATES DISTRICT COURT
DISTRICT OF NEW JERSEY

IN RE ROYAL DUTCH/SHELL TRANSPORT SECURITIES LITIGATION	**Civil Action No. 04-374 (JAP)** **(Consolidated cases)** **Hon. Joel A. Pisano**

ROYAL DUTCH/SHELL TRANSPORT'S
FACTUAL SUBMISSION TO SPECIAL MASTER
RELATING TO EXTENT OF UNITED-STATES-BASED CONDUCT

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PREFACE

Royal Dutch Petroleum Company ("Royal Dutch") and The "Shell" Transport and Trading Company, p.l.c. ("Shell Transport") (collectively, "Shell") are providing this Factual Submission to Special Master (the "Fact Submission") to present the extensive evidentiary record concerning whether investors who resided or were incorporated outside the United States and who purchased Shell securities on non-U.S. markets may sue under the federal securities laws. Shell has summarized the Fact Submission's evidence in the accompanying Summary of Fact Submission (the "Fact Summary"). The Fact Summary and Fact Submission complement the legal briefs to be filed on whether the plaintiffs have met their burden of satisfying the "conduct test."

The evidence presented in the Fact Summary and Fact Submission is drawn from three sources: depositions, documents, and declarations. To that end, Shell submits such evidence in the form of (*i*) full deposition transcripts and videotaped testimony of witnesses deposed in this action, together with relevant exhibits, or deposition transcripts from the regulatory investigations which preceded this action (*ii*) witness declarations and accompanying exhibits, and (*iii*) certain documents previously designated by the parties. This evidence is being submitted to the Special Master in both hard copy (paper) and electronic form. The hard-copy (paper) evidence is organized in binders with descriptive indices. The electronic version of the same data, including the full video testimony is organized into virtual folders. The two sets of evidence are identical, except that the electronic version also includes the video testimony.

Throughout the Fact Summary and Fact Submission, citations to deposition testimony include the name of the deponent and the page and line references from the relevant transcript; citations to witness declarations include the name of the witness and relevant paragraph references, and citations to documents include a brief description of the document and the relevant Bates number or electronic identification numbers.

TAB 1

FACT SUMMARY

I. COMPANY BACKGROUND

Royal Dutch and Shell Transport were, respectively, incorporated under the laws of the Netherlands and the United Kingdom and based in The Hague and London. In 1907, the two companies formed an alliance by which they agreed to merge their interests while remaining separate and distinct entities. This structure remained until 2005, when Royal Dutch and Shell Transport reorganized into a single company, Royal Dutch Shell plc, incorporated in the United Kingdom and headquartered in The Hague, the Netherlands. Because the 2005 reorganization occurred after the end of the Class Period, this factual summary will discuss Shell's structure as it existed before the reorganization.

A. The Royal Dutch/Shell Group

The two parent companies (Royal Dutch and Shell Transport) had no operational activities. They derived their income from their respective interests in the companies known collectively as the Royal Dutch/Shell Group of Companies (the "Group"). Royal Dutch had a 60% ownership interest in the Group's aggregate net assets, dividends, and interest, and Shell Transport had a 40% ownership interest.

Royal Dutch and Shell Transport held their ownership in the Group through two holding companies (the "Group Holding Companies"): Shell Petroleum N.V., incorporated in the Netherlands, and Shell Petroleum Co., Ltd., incorporated in the United Kingdom.

The Group Holding Companies directly or indirectly held all of Shell's interests in two types of companies: operating companies and service companies. The operating companies operated in 145 countries and territories throughout the world. The service companies functioned largely as advisors and service-providers to other Shell entities, such as the operating companies.

The Committee of Managing Directors ("CMD") managed the Group Holding Companies and was responsible for the high-level management of Shell's businesses. Throughout the Class Period, all CMD meetings were held in Europe, never in the United States

Royal Dutch and Shell Transport exercised oversight of the management of the Group through a Conference composed of the members of Royal Dutch's Supervisory Board and Board of Management and Shell Transport's Board of Directors. The Conference held all of its meetings in Europe during the Class Period. The Conference never met in the United States.

B. **Business Segments**

Shell's business structure consists of two overarching components: the "upstream" businesses and the "downstream" businesses.

The "upstream" businesses locate and extract hydrocarbon resources and complete all of the work necessary to bring them to market. Two Shell businesses perform this work. Shell Exploration and Production ("EP") discovers and extracts hydrocarbon resources throughout the world. Shell Gas and Power, which also operates worldwide, liquefies and transports natural gas, develops natural gas markets and infrastructure, develops gas-fired power plants, and performs other gas-related activities. (Some of Gas and Power's operations might be considered "downstream.")

Shell's "downstream" businesses refine crude oil into a range of products, including fuels, lubricants, and petrochemicals. The Oil Products business refines, supplies, trades, and ships crude-oil products throughout the world and markets fuels and lubricants for domestic, industrial, and transportation use. The Chemicals business produces and sells petrochemicals to industrial customers globally.

C. Shell Exploration and Production

Shell EP – whose activities are at issue in this litigation – was headquartered in the Netherlands and was run by the EP Executive Committee (called the EP Business Committee until 1999). The Executive Committee, which was based in the Netherlands, was responsible for developing the strategy and the business plan for the entire EP business.

The EP Executive Committee consisted of Regional Business Directors – who oversaw EP's businesses in different regions of the world – and the heads of EP service groups. During the Class Period, the EP Executive Committee was based in and held all of its meetings in the Netherlands.

1. Regional Directorates

From the beginning of the Class Period until mid-2003, Shell had four Regional Directorates responsible for specified geographic locations: EPG, EPM, EPA, and EPN. EPG covered sub-Saharan Africa and Central and South America. EPM covered the Middle East, Russia, Central Asia, Turkey, Egypt, Libya, and India. EPA covered the Far East and Australia. EPN covered North America, Europe, Algeria, Tunisia, and Morocco. In mid-2003, EP underwent a significant reorganization that led to various changes in the regional reporting lines. As part of this organization, EPN was split into EPE, responsible primarily for Europe, and EPW, responsible primarily for the Americas.

Regional Business Directors headed Shell's Regional Directorates and were based in the Netherlands. Each Directorate also employed Regional Business Advisors, who reported to the Regional Business Directors, oversaw the management of Shell's operating units in their region, and served as liaisons between the operating units and EP management.

2. **Operating Units**

Shell EP supervised some 25 to 35 operating units throughout the world. These operating units, often working with other oil companies and/or governments, were dedicated to maturing the hydrocarbon resources under their jurisdiction.

Each operating unit typically was run by a General Manager or Managing Director, who was responsible only for a particular country and was based in that country or, for some small operating units, at EP headquarters in the Netherlands. Operating units also employed Asset Managers, who oversaw particular fields or blocks (*i.e.*, the "assets") within an operating unit and reported to the unit's General Manager.

Each year, each operating unit had to estimate and report to Shell's EP headquarters its various categories of hydrocarbon resources, including any "proved" reserves. This process required the operating units to assess not only the volumes of hydrocarbons in the ground but also a host of other economic, business-planning, capital-allocation, and commercial factors. In performing these evaluations, some operating units sought technical assistance from Shell service companies, but the operating units themselves remained responsible for their own estimating and reporting. The reporting process is discussed below in greater detail.

3. **Resource Maturation Process**

As a business that extracts and sells oil and gas, EP focuses chiefly on resource maturation – the process of discovering hydrocarbon resources and moving them to production. One Shell official explained that "the resource maturation life cycle from glimmer in the explorer's eye to molecules left in the ground when you abandon a field is the basic business of the exploration and production business."[1] Shell describes this process as a five-part "Resource Maturation Funnel": exploration, appraisal, planning, development, and production.

Exploration. The exploration stage involves looking for new hydrocarbon resources, usually by drilling one or more exploration wells. Exploration work often involves seismic surveying, which allows scientists to create a "picture" of the rock layer structure by using sound waves to map the subsurface.

Appraisal. If an exploration well locates oil or gas with good geological potential, Shell might drill one or more appraisal wells (as necessary) to obtain a better understanding of the reservoir. These appraisal wells help Shell to decide how – or whether – to develop the field. Scientists and engineers use rock cuttings, core samples, and geophysical data from well surveys to gain information during the drilling process.

Planning. If the appraisal process shows a promising amount of hydrocarbons, Shell then formulates a development and production plan for the reservoir. This planning requires an integrated effort among geologists and petrophysicists, reservoir, production, design, and drilling engineers, and production operations staff. This group constructs complex geological models, with sophisticated modeling programs run on powerful super-computers, and uses multi-component reservoir-simulation programs to assess alternatives for developing the field and recovering the resources. The end product of this work is a field-development plan that will specify a number of "development wells" to produce and drain the reservoir effectively.

Economics are important at all times. A field usually is most profitable in its early years, when production is highest and when operating costs are only a small part of expenditure. But the cost of producing each extra barrel from a maturing field increases as

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1 Warren Dep. at 73:8-12.

production declines and maintenance becomes more expensive. The field-development plan therefore must be matched to the anticipated economics of the field's lifetime.

Development. Shell implements the field-development plan in the development stage of the resource-maturation process.

Production. As soon as reasonably possible after development begins, a field goes into production. A field that took three to seven years to find and develop might typically produce hydrocarbons for some 20 to 50 years. Teams of geologists and engineers re-evaluate each field many times during its life cycle, from discovery, development, and production to decommissioning.

FACT SUPPORT

I. COMPANY BACKGROUND

A. Historical Perspective

1. Incorporation

a) Royal Dutch Petroleum Company N.V. ("Royal Dutch") was incorporated on June 16, 1890, under the laws of the Netherlands.

b) The "Shell" Transport and Trading Company, Public Limited Company ("Shell Transport") was incorporated on October 18, 1897, under the laws of England.

(1) Annual Report on Form 20-F 2002, Introduction (RJW00890152-329).

2. Joint-Venture Partnership

a) For close to a century, from 1907 to 2005, Royal Dutch and Shell Transport (collectively "Royal Dutch/Shell" or the "Parent Companies") had been 60:40 joint-venture partners.

(1) Annual Report on Form 20-F 2002, pg. 2 (RJW00890152-329).

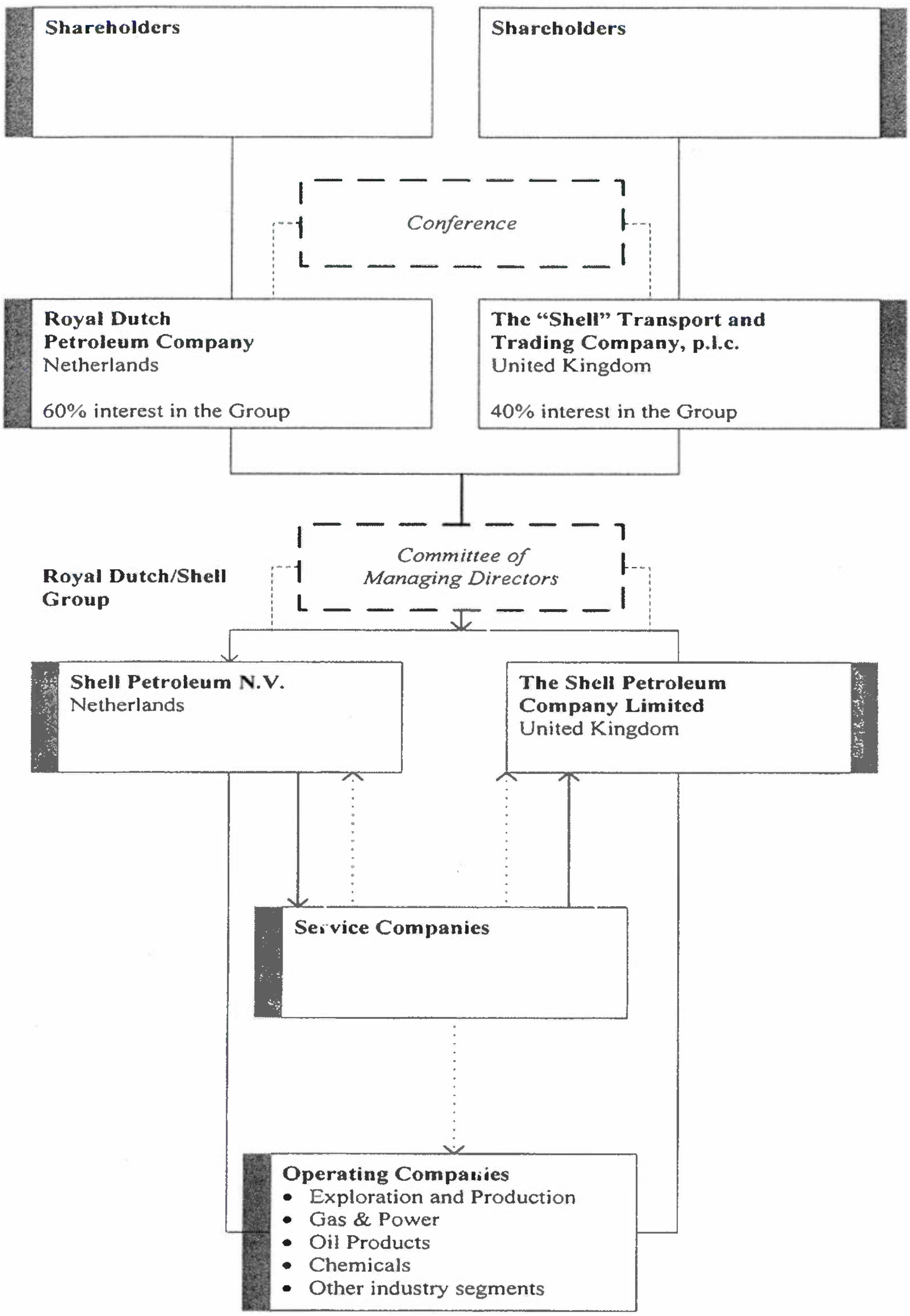
3. 2005 Reorganization

a) In 2005, the Royal Dutch/Shell Group underwent a major structural reorganization. The partnership between Royal Dutch and Shell Transport was dissolved, and a single company – Royal Dutch Shell plc, headquartered in The Hague, the Netherlands – was created.

b) The class period, from April 8, 1999 to March 18, 2004 (the "Class Period") predates the reorganization, so this Factual Submission will focus on the structure of the Group before the reorganization.

c) The following chart (adapted from the Annual Report and Accounts of 2003, pg. 6) (MISC00080427-554) depicts the corporate structure of the Royal Dutch/Shell Group during the Class Period.

B. Structure of the Royal Dutch/Shell Group



1. The Parent Companies

a) The Parent Companies had no operational activities and derived their income from their respective interests in the companies known collectively as the Royal Dutch/Shell Group of Companies.

(1) Annual Report on Form 20-F 2002, Introduction. (RJW00890152-329). (This document provides factual support for all statements in Section I.B.)

2. Royal Dutch/Shell Group of Companies

a) The numerous companies in which Royal Dutch and Shell Transport owned investments were collectively referred to as the Royal Dutch/Shell Group of Companies. Royal Dutch and Shell Transport were the Parent Companies of the Group but were not themselves part of it.

b) In 1907, Royal Dutch and Shell Transport formed an alliance by which they agreed to merge their interests on a 60:40 basis while remaining separate and distinct entities. Arrangements between Royal Dutch and Shell Transport provided that, notwithstanding variations in shareholdings, Royal Dutch and Shell Transport would share in the aggregate net assets, dividends and interest received from Group companies in the proportion of 60:40. The burden of all income taxes leviable in respect of such dividends and interests was shared in the same proportion.

3. Group Holding Companies

a) There were two Group Holding Companies: Shell Petroleum N.V., in the Netherlands, and The Shell Petroleum Company Limited, in the U.K. The Group Holding Companies between them held all the shares in the Service Companies and, directly or indirectly, all Group interests in the Operating Companies.

b) Royal Dutch was entitled to elect its nominees as a majority of the members of the Boards of Directors of the two Group Holding Companies, and Shell Transport was entitled to elect its nominees as the balance.

c) Every member of the Board of Management of Royal Dutch and every Managing Director of Shell Transport was also a member of the Presidium of the Board of Directors of Shell Petroleum N.V. and a Managing Director of The Shell Petroleum Company Limited. Accordingly, they were generally known as "Group Managing Directors."

d) They were also appointed by the Boards of Shell Petroleum N.V. and The Shell Petroleum Company Limited to a joint committee known as the Committee of Managing Directors.

4. Service Companies

a) The main business of the Service Companies was to provide advice and services to other Shell companies.

5. Operating Companies

a) Present in more than 145 countries and territories around the world, the companies of the Royal Dutch/Shell Group are engaged in the business of Exploration and Production, Gas & Power, Oil Products, Chemicals, and Other industry segments, including Renewables, Shell Consumer, and Shell Hydrogen.

b) The management of each Operating Company was responsible for the performance and long-term viability of its own operations.

C. <u>Business Segments</u>

Shell's business is divided into two components: Upstream and Downstream.

1. Upstream

a) Shell's two "Upstream" businesses – Exploration & Production ("EP") and Gas & Power ("GP") – explore for and extract hydrocarbons and build and operate the infrastructure necessary to deliver them to market. (Some of GP's operations might be considered "downstream.")

b) EP is the subject of scrutiny in this litigation. EP explores for and extracts crude oil and natural gas around the globe. It is active in more than 38 countries and normally acts as a partner in joint-venture operations.

c) GP liquefies and transports natural gas, develops natural gas markets and infrastructure, and develops gas-fired power plants. It also markets and trades natural gas and electricity, and converts natural gas to liquids to provide clean fuels.

(1) Annual Report on Form 20-F 2002, pg. 22 (RJW00890152-329).

(2) Van de Vijver

(a) "Upstream is all about finding and getting the hydrocarbons out of the ground, and downstream, just like you have the oil products business, is about marketing and ultimately the distribution of those products." (Dep. pg. 22:7-11)

2. Downstream

a) Shell's "Downstream" businesses refine crude oil into a range of products including fuels, lubricants and petrochemicals. Shell operates the world's largest single-branded retail network.

(1) Van Driel

(a) "Downstream is . . . retail, refineries, that sort of thing. Q. So downstream is where you do the actual selling? A. Correct, to the customers." (Dep. pg. 224:3-7)

(2) Aalbers

(a) "Upstream, that's E&P, so basically exploration and production, versus downstream, which is basically the marketing side." (Dep. pg. 174:2-4)

D. Shell Exploration and Production

1. From its headquarters in the Hague, Shell's Exploration and Production ("EP") business explores for and extracts oil and natural gas around the globe.

a) Henry

(1) "E&P was responsible for identifying hydrocarbon deposits in the ground and extracting them." (Decl. ¶ 13)

E. Leadership of EP Business

1. The leadership of EP resided in the Executive Committee ("ExCom"), which until January 1999 was called the Business Committee ("BusCom"). BusCom supervised the operation of the EP business but did not have executive authority. ExCom was created to give the EP leadership executive authority over EP operations.

2. ExCom was responsible for strategy and business planning. It developed and approved an annual EP business plan and developed and supervised

EP's strategy. It took actions to implement the business plan and strategy and monitored the results. It also made financial and operational decisions concerning the business. The ExCom member with direct responsibility for strategy and planning supervised the work of the Group Hydrocarbon Resources Coordinator, also known as the Group Reserves Coordinator ("GRC"), who compiled the information concerning EP's oil and gas resources.

a) Brass

(1) "[ExCom] was the leadership team of Exploration and Production. It agreed to the strategy of E&P; it developed and agreed to a Business Plan for E&P; it reviewed and took actions as a result of the results, be it financial or operational, of E&P; it decided on levels of expenditure for E&P." (Dep. pg. 88:18-24)

(2) "From 2000 (when I became head of Strategy Planning and Business Development for EP-B) until 2003, the reporting of oil and gas reserves fell under my supervision." (Decl. ¶ 8)

(3) "The Executive Committee was responsible for EP strategy and business planning. . . . The EP Executive Committee held its meetings in The Netherlands." (Decl. ¶ 12)

(4) *See also* Brass Decl. ¶¶ 7, 9, 10.

b) Gardy

(1) "[T]he thing we were discussing at ExCom was fundamentals of the business, which is basically to explore, to find, to develop and to produce." (Dep. pg. 44:4-7)

3. ExCom met once per month in The Hague. Reading material was provided before the meeting about the topics to be addressed. When a decision was required, ExCom members would discuss the matter, and the CEO of EP, who chaired the ExCom, would summarize the discussion and present the conclusion.

a) Gardy

(1) "Q. How often did ExCom meet? A. . . . I think it was once a month. Q. [W]ere minutes kept of the ExCom meetings? A. Yes. . . . Q. . . . [W]as someone in charge? A. . . . We were all part of ExCom, and we had one boss: Mr. Watts. Q. Did ExCom operate as a democracy? Did you take votes on issues? . . . A: We received some pre-

reading before ExCom, and when we discussed the various topics, then decisions were made and minuted. Q. Did Mr. Watts have the final say on any decisions that were made? . . . A. Again the decision was made, depending on the topic, around the table, and was minuted." (Dep. pg. 36:21-38:5)

b) Brass

(1) "Q. Did the ExCom meet regularly? A. Yes. Q. How regularly? A. In 2000, as I recall, it was approximately monthly. Q. When there were decisions to be made at the ExCom level, were they made by the group collectively? A. The process, as I remember it, is that there was – for those that needed decisions and could be taken at the level of the ExCom, financially and otherwise, debate would be – issues would be discussed that had been given pre-read into the ExCom materials. Everyone was looked to for their views, and at the conclusion of which typically, while Mr. Watts, Phil Watts, was on the Chair, to be sure, he many times went around the room and asked everyone their views, and then he stated the decision." (Dep. pg. 88:25-89:19)

(2) "The Committee typically met on a monthly basis to set business strategy, develop the business plan, review group results, and take any financial or operational actions it deemed necessary in light of those results. . . . The EP Executive Committee held its meetings in the Netherlands." (Decl. ¶ 12)

4. ExCom was composed of Regional Business Directors ("RBDs"), who supervised the activities of EP operating units within their geographic region, and the heads of EP's service groups, such as Technology, New Business Development, Exploration, and Human Resources.

a) Darley

(1) "The structure around the operating units was that of what we call regional directorates at that time. There were five regional directorates covering the major geographic divisions. Within each of those geographic divisions [there] were individual operating units dealing with the matters of the day of the production of oil and gas, exploration, production and development of oil and gas. Supporting the operating units and the activities of the business were a number of corporate organizations, so

finance organization, HR organization, and EP technology, the organization which – of which I became director." (Dep. pg. 8:18-9:12)

b) J. Bell

(1) "Q. Do you recall who the members of the Ex Com were at the time of this presentation of February 4, 2002? A. Yes, I do. Q. And who were they? A. You want all 12 of them? Q. Yes. A. All right. Okay. The Regional Director for Europe was Bob Sprague. For the Middle East was Din Megat. For the – for Africa it was Brian Ward. For Asia it was Tim Warren. And for the Americas it was Raoul Restucci. And then we had John Darley who was the Head of the Technical Group. Lorin Brass, Head of New Business Development and Planning. Matthias Bichsel was the Head of Exploration. Carol Dubnicki was the Head of HR. At this time, Dominique Gardy still as the CFO, and Walter as the CEO, and I think Curtis Frasier was at that time or about to become the Legal Director." (Dep. pg. 163:4-22)

c) Brass

(1) "The Committee consisted of the heads of the EP service groups and [RBDs]. RBDs are Shell managers responsible for particular geographic areas." (Decl. ¶ 12)

5. As with other EP matters, ExCom supervised the estimation and reporting of operating units' oil and gas resources, including proved reserves. ExCom received reports on the oil and gas resources associated with projects whose funding was contemplated. As discussed below, ExCom also received a year-end summary of changes in operating units' proved reserves and an estimate of EP's aggregate proved-reserves portfolio. ExCom's approval of the aggregate proved-reserves estimate was necessary for Shell to report the proved reserves externally.

a) Aalbers

(1) "The . . . regional business directors are responsible of their respective areas, so if there would be an issue with any specific reserve booking for a specific country, that would go – that would be escalated through the regional business advisor, and – and the regional business director would get involved." (Dep. pg. 181:11-17)

F. Regional Directorates

1. From the beginning of the Class Period until late 2003, there were four regional directorates: EPG (covering sub-Saharan Africa and Central and South America), EPA (covering the Far East and Australasia), EPM (covering the Middle East, Russia, Central Asia, Turkey, Egypt, Libya, and the Indian Sub-Continent), and EPN (covering North America, Europe, Algeria, Tunisia and Morocco). *See* EP ExCom 1999 Business Plan – Volume 2 (RJW00861093-203).

a) Van Driel

(1) "Q. [What does EPM stand for? A. Roughly Middle East. Q. And that covered which OUs, other than Oman? A. Well, Egypt, Syria, Abu Dhabi. Q. Okay. And with regard to the regions you at least undertook originally, what does EPN stand for? A. North America and Europe, essentially that's what it amounts to." (Dep. pg. 155:3-12)

2. Following the late 2003 reorganization, EPN ceased to exist, and EPE (covering Europe) and EPW (covering the Americas, including Central and South America) were created.

a) Knight

(1) "I recall . . . the changes occurred after . . . late 2003. . . . The changes I believe were going from individual operating units around the world [to] try to connect them together. The example I would give is in the North Sea where I'm at present where we had different operating units around the North Sea. And now they are combined together in one company called EPE." (Dep. pg. 66:4-21)

3. RBDs were the appointed heads of each Regional Directorate and were based in The Hague. In the late 2003 reorganization, each RBD assumed the title of CEO for EP activities in his region.

a) Ward

(1) "Q. [C]an you describe how the reorganization affected your position? A. It affected my position in the sense that in the first case we went from an advisory role as regional business directors, to CEOs, chief executive officers for the region. And secondly, I moved regions over to Africa. Q. So after the reorganization what was your title? A. CEO Africa, exploration and production. Q. Is that also known as EPG? A. EPG was my department. Q. What do you mean by your department? A. The people who worked for

me myself were collectively referred to as EPG." (Dep. pg. 27:2-21)

4. Regional Business Advisors ("RBAs") reported to the RBDs and oversaw the management of individual operating units in various countries.

a) Roosch

(1) "Q. Is there a difference between a regional business advisor and a regional business director? A. Yes. The advisor works for the director." (Dep. pg. 150:15-19)

b) Aalbers

(1) "Q. . . . Is there a difference between a regional business advisor and a regional business director? A. Yes. The regional business director is actually the responsible actor for one of the four regions that we had at the time, and he has a number of regional business advisors reporting to him who look after one or two or sometimes three specific countries." (Dep. pg. 110:8-16)

c) Parry

(1) "The regional business advisor position was responsible for generating new activity, new exploration activity, and also possible divestments of existing activities. We were also involved in the governments of various Shell entities within our areas. So, for instance, in sub-Saharan Africa, I was looking after various exploration ventures including Namibia, Angola, Congo, Ivory Coast, ventures that were purely exploration, not production." (Dep. pg. 16:8-17)

(2) "Q. How many business advisors were there, regional business advisors, within EPG? A. At any one time, there would have been eight or nine, to my recollection." (Dep. pg. 19:7-10)

d) Duhon

(1) "An RBA . . . was essentially an internal governance role in which the RBA had duties to work with particular Operating Units, either to steer and advise what they were doing or in some cases to champion what they were doing internally, or in other cases to assist with new business development activities within the scope of that Business Unit." (Dep. pg. 15:4-11)

e) Harper

(1) "[RBAs] would review the performance of the operating units, we would review the plans of the operating units, and we would provide advice to the, to the Regional Business Director." (Dep. pg. 21:15-19)

5. RBAs were liaisons between EP and the operating units.

a) Graham

(1) "Q. What do you understand the role of a regional business advisor to be? . . . A. He facilitates the conversation between the operating unit and the center. So he would come from The Hague and be the face of the center to the operating unit, but conversely, in any meetings in the center he would be the face of SDA. Q. So he's kind of a liaison? A. Yes. Q. Who's stationed in The Hague? A. Yes." (Dep. pg. 57:10-25)

G. <u>Operating Units</u>

1. Within EP, 25 to 35 operating units existed around the globe at different times.

a) J. Bell

(1) "The EP, prior to the end of 2003, beginning of 2004, was a – I would describe it as a federation of relatively autonomous relatively self-sufficient and relatively lightly governed Operating Units, some 25 to 35 of them." (Dep. pg. 184:7-11)

2. An operating unit was run by a Managing Director or General Manager, who was responsible for directing the operating unit's activities, including supervising the maturation of the unit's resources.

a) Van de Vijver

(1) "Q. Now, is there a difference between a Managing Director and a Regional Business Director? A. . . . [T]he Regional Business Director has responsibility for a particular region, and someone sitting in a country only has responsibility for the country where he is located." (Dep. pg. 98:24-99:13)

3. Asset Managers oversaw particular fields or blocks (*i.e.*, "assets") within an operating unit.

a) Newberry

(1) "Q. So the record is clear, what do you mean by 'Asset Manager'? A. . . . [F]rom a business and commercial standpoint, he was responsible for Shell's interest within Angola Block 18." (Dep. pg. 123:7-11)

H. Resource Maturation Process

1. Resource Maturation as Shell's Chief Focus

a) The primary commercial objective of EP was, as its name suggests, the exploration and production of oil and gas resources. The estimation and reporting of "proved reserves" was not the focus of EP's hydrocarbon-maturation effort. Instead, it was merely a mandatory consequence of the fact that Shell securities traded in the United States and that Shell therefore filed financial statements with the United States Securities and Exchange Commission ("SEC").

(1) Warren

(a) "[T]he whole business value chain of an exploration and production business is discovering hydrocarbons in the exploration phase, having the confidence to go in and discover them in the first place, to having discovered them, to appraise them to a stage where you're willing to invest in their development. Ultimately to produce them, sell them, operate them until you're at the stage where you have to abandon a field." (Dep. pg. 105:9-18)

(b) "The speed at which we were moving resources across the broad resource classification was of concern to us. . . . This captures within the company a much larger initiative, as I say, which was to discover, develop, and produce our resources faster and more cost effectively than we had done before." (Dep. pg. 96:22-24, 97:22-25, 98:2)

2. EP's chief goal was efficiently to mature hydrocarbons through the various stages of field maturity, from exploration (the locating of oil and gas reservoirs in subsurface areas) through appraisal (the gathering of technical data concerning those reservoirs), planning (the formulation of a plan to extract the oil and gas from the subsurface in an economical

manner), and development (the execution of the development plan) to the income-generating production phase (the extraction of the hydrocarbons for sale).

a) Sears

(1) Described the stages of maturation as "exploration, appraisal, development, production, abandonment." (Dep. pg. 42:4-7)

TAB 2

FACT SUMMARY

II. TRADING OF SHELL SECURITIES

Royal Dutch's shares were primarily listed on the company's home exchange in the Netherlands, the Euronext Amsterdam. Its shares also traded on exchanges in the United Kingdom, Belgium, Germany, Luxembourg, France, Switzerland, and Austria, as well as on the New York Stock Exchange (the "NYSE").

Similarly, Shell Transport's ordinary shares were primarily listed on its home exchange in the United Kingdom, the London Stock Exchange (the "LSE"). Its shares also traded on exchanges in Belgium, Germany, and France, and its American Depository Receipts ("ADRs") were listed on the NYSE.

The geographic distribution of Shell's securities is not mere background information in this case. Rather, it is important because it determines the portion of the worldwide putative class that may assert claims under the federal securities laws. If most of the Shell shares had been available for trading and actually had traded in the United States, the conduct-test issue presented to the Special Master (and the Court) would have assumed far less prominence than it has done to date. But where, as here, most of the shares were available for trading and actually traded only *outside* the United States, the conduct test becomes a critical and dispositive issue for the vast majority of the putative class.

The unrefuted evidence demonstrates that the overwhelming majority of Shell's shares were registered in Europe and were traded on European markets by Non-U.S. Purchasers during the Class Period.

- Approximately 92% of the combined total of Royal Dutch and Shell Transport shares were registered in Amsterdam and London; only about 8% were registered in the United States.

- Approximately 88.4% of the combined Royal Dutch and Shell Transport shares traded during the Class Period were traded in Amsterdam and London; only about 11.6% were traded in the United States.

- Non-U.S. Purchasers' trading on non-U.S. markets accounted for about 85% of the total shares traded during the Class Period. Trading on the NYSE by all persons, regardless of their domicile, plus U.S. investors' trading on non-U.S. markets accounted for only about 15% of the shares traded during the Class Period.

A. **Geographic Distribution of Registered Shares**

Only a minimal number of Shell shares were registered for trading in the United States; most were registered on European exchanges. According to Shell's Annual Report on Form 20-F for 2003, the number of Shell shares registered in New York as of June 14, 2004 was as follows:

- 513,969,157 outstanding shares of Royal Dutch New York Registry (or New York Ordinary) Shares ("NYOs"), representing about 24.7% of Royal Dutch's ordinary share capital and held by about 17,800 holders of record, and

- 69,584,433 outstanding Shell Transport ADRs, each of which represented six ordinary shares of Shell Transport stock, representing about 4.32% of Shell Transport's ordinary share capital and held by 2,100 holders of record.

These approximately 931.4 million shares constituted only 8% of Royal Dutch and Shell Transport's combined total of approximately 11.75 billion shares. The remaining amount of the combined shares – approximately 10.8 billion shares, or 92% – was registered in Amsterdam and London.[2]

B. **Volumetric Distribution of Shares Actually Traded During Class Period**

Of the registered shares discussed above, the overwhelming majority of shares actually traded during the Class Period were traded in Europe, not in the United States.

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2 Clark Decl. ¶¶ 9-10.

Lexecon Inc. compiled the publicly available data on the volume of Royal Dutch and Shell Transport securities actually traded on the primary exchanges during the Class Period.[3] The volumetric data show that:

- 10,272,341,132 Royal Dutch ordinary shares, representing about 17.1% of all Shell securities traded during the Class Period, were traded on Euronext Amsterdam.
- 3,584,043,057 Royal Dutch NYOs, representing about 6.0% of all Shell securities traded during the Class Period, were traded on the NYSE.
- 43,396,789,823 Shell Transport ordinary shares, representing about 72.2% of all Shell securities traded during the Class Period, were traded on the LSE.
- 468,930,745 Shell Transport ADRs (which were equivalent to 2,813,584,470 ordinary shares), representing about 4.7% of all Shell securities traded during the Class Period, were traded on the NYSE.

These reported volumes also were adjusted to account for possible "double-counting" of reported purchases due to activities of specialists, dealers, and market-makers, as well as other intraday trading. In securities cases, reported volume commonly is reduced for auction markets such as the NYSE by 20% and for dealer markets such as the NASDAQ by 60%. The LSE is structured like the NYSE, so its reported volume was reduced by 20%. The Euronext Amsterdam is structured like the NASDAQ, so its reported volume was reduced by 60%. The adjusted volumetric distribution is as follows:

- 4,108,936,453 Royal Dutch ordinary shares, representing about 9.4% of all Shell securities traded during the Class Period, were traded on Euronext Amsterdam.
- 2,867,234,446 Royal Dutch NYOs, representing about 6.5% of all Shell securities traded during the Class Period, were traded on the NYSE.

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[3] The volumes of Royal Dutch and Shell Transport shares traded on exchanges in Austria, Belgium, France, Germany, Luxembourg, and Switzerland, and of Royal Dutch shares traded in the United Kingdom, were not included in these calculations, because the overwhelming majority of shares were traded on Euronext Amsterdam, the LSE, and the NYSE.

- 34,717,431,858 Shell Transport ordinary shares, representing about 79% of all Shell securities traded during the Class Period, were traded on the LSE.
- 375,144,596 Shell Transport ADRs (which were equivalent to 2,250,867,576 ordinary shares), representing about 5.1% of all Shell securities traded during the Class Period, were traded on the NYSE.

Thus, based on the reported volume data, approximately 89.3% of Royal Dutch and Shell Transport's combined shares that were traded during the Class Period were traded in Amsterdam and London, while approximately 10.7% of the combined shares were traded in the United States. Based on the adjusted volume data, approximately 88.4% of Royal Dutch and Shell Transport's combined shares traded during the Class Period were traded in Amsterdam and London, while approximately 11.6% of the combined shares were traded in the United States.[4] (For purposes of this narrative, Shell will use the lower number, *i.e.*, 88.4%.)

C. **Non-U.S. Purchasers' Share of Non-U.S. Trading**

Plaintiffs have contended that some unspecified portion of the Shell shares actually traded in Europe during the Class Period (*i.e.*, the 88.4% discussed above) was traded by investors from the United States ("U.S. Investors"), not by Non-U.S. Purchasers. After extensive analysis, however, Shell has determined that no more than 3% of the trading on European exchanges during the Class Period was done by U.S. Investors. Thus, approximately 85% of the Royal Dutch and Shell Transport shares traded on European exchanges were traded by Non-U.S. Purchasers, not by U.S. Investors. While plaintiffs have disputed these figures, they have not offered a shred of evidence to refute them.

Shell retained Thomson Corporate Advisory Services ("Thomson") to identify the number of Shell shares that investors from the United States purchased on *all* relevant markets – whether Royal Dutch or Shell Transport ordinary shares registered in Amsterdam or London, or

4 Clark Decl. ¶¶ 11-16.

Royal Dutch NYOs or Shell Transport ADRs registered in New York. That number then could be compared with the total trading volume to determine how much of the non-U.S. trading was done by Non-U.S. Purchasers, whose claims are at issue here.

Thomson was able to obtain sufficient trading data to calculate the total number of Royal Dutch and Shell Transport ordinary shares, Royal Dutch NYOs, and Shell Transport ADRs purchased from October 1999 through March 2004 (the "Report Period"), a period close to the length of the Class Period (which began on April 8, 1999 and ended on March 18, 2004). Thomson used (*i*) real-time data fees from the stock exchanges, (*ii*) custodian bank lists from HSBC, State Street Bank, Investors Bank & Trust Company, Depository Trust Company, Bank of New York, Northern Trust Corporation, JPMorgan Chase, and other custodians, (*iii*) institutional investment managers' public filings, and (*iv*) data from Broadridge Financial Solutions Inc. ("Broadridge"), which is the largest processor of beneficial proxies in the United States and has extensive lists of investors.[5]

Thomson then researched the residence or domicile of investors to determine whether the investor was a U.S. Investor or an investor from outside the United States. In identifying U.S. Investors, Thomson examined literally billions of shares to ascertain ownership.

- For Royal Dutch, Thomson examined approximately 1.047 billion Ordinary Shares and approximately 713 million NYOs.
- For Shell Transport, Thomson examined approximately 3.502 billion Ordinary Shares and approximately 123 million ADRs.

Thomson sometimes was able to determine the beneficial owners' geography based on the information in the custodian-bank lists. Other times, Thomson determined the beneficial owners of NYOs and ADRs based on lists obtained from Broadridge. Where the

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[5] Clark Decl. ¶¶ 17-49.

beneficial owners' geography was not immediately apparent, Thomson consulted institutional investors' public prospectuses and made direct inquiries to those funds.[6]

Based on these detailed studies, Thomson concluded that no more than 3% of the European trading in Royal Dutch and Shell Transport securities (*i.e.*, the 88.4% discussed above in Section II.B) was conducted by U.S. Investors during the Report Period. Thus, trading by Non-U.S. Purchasers outside the United States accounted for approximately 85% of the total shares traded during the Class Period (*i.e.*, 88.4% less 3%). Trading by U.S. Investors on non-U.S. markets plus trading by U.S. Investors and non-U.S. investors in the United States accounted for only about 15% of the shares traded during the Class Period.[7]

Accordingly, by any measure, this case predominately involves non-U.S. investors who purchased non-U.S. securities on non-U.S. markets and who are complaining about a non-U.S. company's alleged conduct outside the United States.

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6 Clark Decl. ¶¶ 50-56.

7 Clark Decl. ¶ 21.

FACT SUPPORT

II. TRADING OF SHELL SECURITIES

A. Introduction

1. During the Class Period, the securities of Royal Dutch and Shell Transport traded on a number of different exchanges.

a) Royal Dutch

(1) Royal Dutch's shares were primarily listed on the Euronext Amsterdam stock exchange, but its shares also traded on exchanges in Austria, Belgium, France, Germany, Luxembourg, and the United Kingdom, as well as on the New York Stock Exchange ("NYSE").

(a) *See* Henry Decl. ¶ 6.

(2) Royal Dutch shares registered in Amsterdam and traded on European exchanges are hereinafter referred to as "Royal Dutch Ordinary Shares."

(3) Royal Dutch shares registered and traded on the NYSE are hereinafter referred to as "Royal Dutch New York Ordinary Shares" or "Royal Dutch NYOs."

b) Shell Transport

(1) Shell Transport's ordinary shares were primarily listed on the London Stock Exchange ("LSE"), but its shares also traded on exchanges in Belgium, France, and Germany. In addition, American Depository Receipts ("ADRs"), each representing six ordinary shares of Shell Transport, were traded on the NYSE.

(a) *See* Henry Decl. ¶ 7.

(2) Shell Transport shares registered in London and traded on European exchanges are hereinafter referred to as "Shell Transport Ordinary Shares."

(3) Shell Transport ADRs registered and traded on the NYSE are hereinafter referred to as "Shell Transport ADRs."

B. Geographic Distribution of Registered Shares

1. Foreign private issuers such as Shell must make certain filings with the SEC, including Annual Reports on Form 20-F.

   a) *See* Clark Decl. ¶ 8.

2. Only a minimal number of Shell shares were registered for trading in the United States; most were registered on European exchanges. According to Shell's Annual Report on Form 20-F for the year 2003, the number of Shell shares registered in New York as of June 14, 2004 was as follows:

   a) Royal Dutch

      (1) 513,969,157 outstanding Royal Dutch NYOs, representing about 24.7% of Royal Dutch's ordinary share capital and held by about 17,800 holders of record.

         (a) *See* Clark Decl. ¶ 9(a).

         (b) *See* Scaturro Decl. ¶ 4(a).

   b) Shell Transport

      (1) 69,584,433 outstanding Shell Transport ADRs (each ADR being equal to six Ordinary Shares), representing about 4.32% of Shell Transport's ordinary share capital and held by 2,100 holders of record;

         (a) *See* Clark Decl. ¶ 9(b).

         (b) *See* Scaturro Decl. ¶ 4(b).

   c) Combined Shell Group

      (1) Thus, for Royal Dutch and Shell Transport's combined total of approximately 11.75 billion shares, approximately 931.4 million shares – or 8% – were registered in the United States.

      (2) The remaining amount of the combined shares – approximately 10.8 billion shares, or 92% - was registered in Amsterdam and London.

         (a) *See* Clark Decl. ¶ 10.

         (b) *See* Scaturro Decl. ¶ 4(c).

C. Volumetric Distribution of Shares Actually Traded During Class Period

1. Of the registered shares discussed above, the overwhelming majority of shares actually traded during the Class Period were traded in Europe, not in the United States.

2. Lexecon Inc. compiled the publicly available data on the volume of Royal Dutch and Shell Transport securities actually traded on the primary exchanges during the Class Period.[1]

   a) *See* Clark Decl. ¶ 11.

3. The reported volumetric data show that:

   a) Royal Dutch

      (1) 10,272,341,132 Royal Dutch Ordinary Shares, representing about 17.1% of all Shell securities traded during the Class Period, were traded on Euronext Amsterdam.

         (a) *See* Clark Decl. ¶ 13(a).

         (b) *See* Scaturro Decl. ¶ 6(a).

      (2) 3,584,043,057 Royal Dutch NYOs, representing about 6.0% of all Shell securities traded during the Class Period, were traded on the NYSE.

         (a) *See* Clark Decl. ¶ 13(b).

         (b) *See* Scaturro Decl. ¶ 6(b).

   b) Shell Transport

      (1) 43,396,789,823 Shell Transport Ordinary Shares, representing about 72.2% of all Shell securities traded during the Class Period, were traded on the LSE.

         (a) *See* Clark Decl. ¶ 13(c).

         (b) *See* Scaturro Decl. ¶ 6(c).

[1] The overwhelming majority of Royal Dutch and Shell Transport shares traded during the Class Period were traded on Euronext Amsterdam, the LSE, and the NYSE. Accordingly, the volumes of Royal Dutch and Shell Transport shares traded on exchanges in Austria, Belgium, France, Germany, Luxembourg, and Switzerland, as well as the volume of Royal Dutch shares traded in the United Kingdom, were not included in these calculations. *See* Clark Decl. ¶ 15.

(2) 468,930,745 Shell Transport ADRs (which are equivalent to 2,813,584,470 Shell Transport Ordinary Shares), representing about 4.7% of all Shell securities traded during the Class Period, were traded on the NYSE.

(a) *See* Clark Decl. ¶ 13(d).

(b) *See* Scaturro Decl. ¶ 6(d).

4. These reported volumes also were adjusted to account for possible "double-counting" of reported purchases due to activities of specialists, dealers, and market-makers, as well as other intraday trading.

a) In securities cases, reported volume commonly is reduced for auction markets such as the NYSE by 20% and for dealer markets such as the NASDAQ by 60%. The LSE is structured like the NYSE, so its reported volume was reduced by 20%. The Euronext Amsterdam is structured like the NASDAQ, so its reported volume was reduced by 60%.

(1) *See* Clark Decl. ¶ 12.

b) The adjusted volumetric distribution is as follows:

(1) Royal Dutch

(a) 4,108,936,453 Royal Dutch Ordinary Shares, representing about 9.4% of all Shell securities traded during the Class Period, were traded on Euronext Amsterdam.

(i) *See* Clark Decl. ¶ 14(a).

(b) 2,867,234,446 Royal Dutch NYOs, representing about 6.5% of all Shell securities traded during the Class Period, were traded on the NYSE.

(i) *See* Clark Decl. ¶ 14(b).

(2) Shell Transport

(a) 34,717,431,858 Shell Transport Ordinary Shares, representing about 79% of all Shell securities traded during the Class Period, were traded on the LSE.

(i) *See* Clark Decl. ¶ 14(c).

(b) 375,144,596 Shell Transport ADRs (which are equivalent to 2,250,867,576 Shell Transport Ordinary Shares), representing about 5.1% of all Shell securities traded during the Class Period, were traded on the NYSE.

(i) *See* Clark Decl. ¶ 14(d).

5. Reported and Adjusted Volume for Combined Shell Group

a) Thus, based on the reported volume data, approximately 89.3% of Royal Dutch and Shell Transport's combined shares traded during the Class Period were traded in Amsterdam and London, while approximately 10.7% were traded in the United States.

(1) *See* Clark Decl. ¶ 16.

(2) *See* Scaturro Decl. 6(e).

b) Based on the adjusted volume data, approximately 88.4% of Royal Dutch and Shell Transport's combined shares traded during the Class Period were traded in Amsterdam and London, while approximately 11.6% were traded in the United States.

(1) *See* Clark Decl. ¶ 16.

D. <u>Non-U.S. Investors' Share of Non-U.S. Trading</u>

1. Shell retained Thomson Corporate Advisory Services ("Thomson") to identify the number of Shell shares that investors who resided or were incorporated in the United States ("U.S. Investors") purchased on *all* relevant markets – whether Royal Dutch or Shell Transport Ordinary Shares registered in Amsterdam or London, or Royal Dutch NYOs or Shell Transport ADRs registered in New York.

a) Thus, in addition to the trading volume that Lexecon's volumetric analysis identifies as having taken place in Europe (*i.e.* the 89.3% and 88.4% described above), Thomson quantified the percentage of that foreign trading volume attributable to U.S. Investors.

(1) *See* Clark Decl. ¶¶ 17-18.

(2) *See* Scaturro Decl. ¶ 7.

b) That number then could be compared with the total trading volume to determine how much of the non-U.S. trading was done by investors who resided or were incorporated outside the United States ("Non-U.S. Investors").

2. To perform its assignment, Thomson researched trading activity in Royal Dutch and Shell Transport Ordinary Shares, Royal Dutch NYOs, and Shell Transport ADRs purchased from October 1999 through March 2004 (the "Report Period"), a period close to the length of the Class Period (which began on April 8, 1999 and ended on March 18, 2004). Thomson used the Report Period because only limited data were available for the period from April through September 1999.

   a) *See* Clark Decl. ¶¶17, 19.

   b) *See* Scaturro Decl. ¶ 1.

3. Using a proprietary identification method, Thomson sought to identify the number of ordinary shares, NYOs, and ADRs of Royal Dutch and Shell Transport purchased by U.S. Investors during the Report Period.

   a) First, Thomson collected sufficient trading volume data from various sources to calculate the total number of ordinary shares, NYOs, and ADRs purchased during the Report Period.

   b) Second, Thomson researched the residence or domicile of investors to determine whether an investor was a U.S. Investor or a Non-U.S. Investor.

      (1) *See* Clark Decl. ¶ 20.

4. Data Sources

   a) The first step in Thomson's proprietary identification method was to collect trading volume data from a number of different sources: real-time data feeds, custodian bank lists, public filings, and Broadridge Financial Solutions, Inc. ("Broadridge"). Thomson used this data to calculate the total number of Royal Dutch and Shell Transport Ordinary Shares, Royal Dutch NYOs, and Shell Transport ADRs purchased during the Report Period.

      (1) Trading volume data

         (a) Thomson collected trading volume data from a number of its sources. These sources obtain the trading data directly from the stock exchanges.

            (i) *See* Clark Decl. ¶¶ 23-28.

            (ii) *See* Scaturro Decl. ¶ 8.

      (2) Custodian bank lists

(a) A "custodian" is a bank or other financial institution that keeps custody of stock certificates and other assets of a mutual fund, individual, or corporate client.

(b) Mutual funds and other institutional investors usually hold the largest quantity of shares in a company and, accordingly, are the primary clients of custodians. Individual/retail shareholders, however, also use the services of custodians.

(c) Using the custodian bank lists, Thomson was able to identify specific purchases of shares by specific investors or beneficial owners. Those share purchases that are attributable to identified investors are referred to as "Identified" shares.

(d) In addition, the custodian bank lists usually identify the geographic location of the beneficial owner of shares.

(i) *See* Clark Decl. ¶¶ 29-40.

(ii) *See* Scaturro Decl. ¶ 9.

(3) Broadridge Financial Solutions, Inc.

(a) Broadridge is a leading full-service provider of investor communications for the investor relations industry.

(b) Thomson contacted Broadridge to obtain information about certain purchasers of Royal Dutch NYOs and Shell Transport ADRs on the NYSE.

(i) *See* Clark Decl. ¶¶ 44-49.

(ii) *See* Scaturro Decl. ¶ 10.

(4) Public Filings

(a) Institutional investment managers having equity assets under management of $100 million or more are required to file a quarterly report of their equity holdings with the SEC. These quarterly reports are known as Form 13-F.

(i) *See* Clark Decl. ¶¶ 41-43.

(ii) *See* Scaturro Decl. ¶ 11.

5. Identifying U.S. Investors

a) Thomson's next step was to research the residence or domicile of investors to determine whether the investor was a U.S. Investor or a Non-U.S. Investor.

(1) *See* Clark Decl. ¶¶ 50, 52-54.

b) In identifying U.S. Investors, Thomson examined literally billions of shares to ascertain ownership:

(1) For Royal Dutch, Thomson examined (*i*) approximately 1.047 billion Ordinary Shares and (*ii*) approximately 713 million NYOs.

(2) For Shell Transport, Thomson examined (*i*) approximately 3.502 billion Ordinary Shares and (*ii*) approximately 123 million ADRs.

(a) *See* Clark Decl. ¶ 51.

c) Sometimes, Thomson was able to determine the beneficial owners' geography based on information in the custodian bank lists. Other times, Thomson determined the geography of beneficial owners of NYOs and ADRs based on the non-objecting beneficial owner lists it obtained from Broadridge.

(1) Occasionally, the geography of the beneficial owner of ordinary shares and ADRs was not immediately apparent to Thomson. In such cases, Thomson consulted public prospectuses of funds to ascertain the regions to which funds were marketed. If the beneficial owner's geography was still not apparent, Thomson made a direct inquiry to the fund.

(a) *See* Clark Decl. ¶¶ 55-56.

6. Summary of Thomson's Conclusions

a) Based on its review of this data, Thomson concluded the following:

(1) Of the total Identified Royal Dutch Ordinary Shares purchased in Europe during the Report Period, U.S. Investors accounted for approximately 3%.

(a) *See* Clark Decl. ¶ 62.

(b) *See* Scaturro Decl. ¶ 13(a).

(2) Of the total Identified Shell Transport Ordinary Shares purchased in Europe during the Report Period, U.S. Investors accounted for approximately 2.3%.

(a) *See* Clark Decl. ¶ 64.

(b) *See* Scaturro Decl. ¶ 13(b).

b) In sum, Thomson ultimately concluded that no more than 3% of European trading in Royal Dutch and Shell Transport securities (*i.e.*, the 88.4% to 89.3% described above) was conducted by U.S. Investors during the Report Period. Thus, trading by Non-U.S. Investors outside the United States accounted for approximately 85% to 86% of the total shares traded during the Class Period. Trading by U.S. Investors on non-U.S. markets plus trading by U.S. and Non-U.S. Investors in the United States accounted for about 14% to 15% of the shares traded during the Class Period.

(1) *See* Clark Decl. ¶ 21.

TAB 3

FACT SUMMARY

III. CLASSIFICATION OF HYDROCARBON VOLUMES

To make effective business decisions, an oil and gas company must maintain a thorough inventory and analysis of its hydrocarbon resources. In addition, the SEC prescribes certain reporting requirements for oil and gas companies such as Shell.

The SEC requirements focus only on "proved" reserves, while Shell's internal guidelines consider the whole spectrum of available hydrocarbon resources, not just proved reserves. Shell bases its business decisions on what it calls "expectation reserves," or the most likely amount of reserves to be economically extracted from a reservoir, even if those reserves cannot (yet) be considered "proved."

A. **SEC Reporting Rules**

In 1982, the Financial Accounting Standards Board promulgated Statement of Financial Accounting Standards ("SFAS") 69, which requires publicly traded companies with "significant oil and gas producing activities" to report their "proved" crude-oil, natural-gas, and natural-gas-liquids reserves as supplemental information to their annual financial statements. SFAS 69, ¶ 7. Companies are not permitted to report reserves that are not "proved."

SFAS 69 took its definition of "proved reserves" from Rule 4-10 of the SEC's Regulation S-X, which the SEC had adopted in 1978. Rule 4-10 defines "proved oil and gas reserves" as "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." 17 C.F.R. § 240.4-10(a)(2) (emphasis added).

While Rule 4-10 provides detailed requirements on particular technical issues (such as the definition of a proved area), it gives little concrete guidance about the requisite economic conditions and the meaning of "reasonable certainty." Shell and the rest of the energy industry therefore were left to interpret those phrases through the prisms of their respective business operations and practices.

Finally, on June 30, 2000 – 22 years after Rule 4-10's adoption – the staff of the SEC's Division of Corporation Finance issued informal guidance on several issues pertaining to financial statements, including the definition of "proved reserves." *Current Accounting and Disclosure Issues* (June 30, 2000). The staff acknowledged that it was acting because it had observed "issues of consistency and, therefore, some confusion in the reporting of proved oil and gas reserves." *Id.* at 42. The staff also conceded that the guidance was its own and did not state a formal SEC position. *Id.*

The staff took the position that, for "frontier" areas (an undefined term), an issuer could not report reserves as proved without a "commitment" by the company to develop the hydrocarbons in that field. The staff also warned about booking proved reserves requiring government approvals or licenses without a substantial level of certainty based on "a long and clear track record which supports the conclusion that such approvals and renewal are a matter of course." *Id.* at 44. The staff reissued its guidance more formally on March 31, 2001. *Frequently Requested Accounting and Financial Reporting Interpretations and Guidance* (Mar. 31, 2001).

B. **<u>Shell's Internal Guidelines for Hydrocarbon Classification</u>**

While the SEC's Rule 4-10 focused only on external reporting of hydrocarbon reserves, Shell also needed to consider how to run its own business – how to make worldwide strategy, investment, and planning decisions that were not limited solely to "proved" reserves as defined by the SEC. Instead, Shell needed a broader review of its global resources, whether proved or less than proved. Shell therefore used its own Petroleum Resource Volume Guidelines (the "Shell Guidelines") both to inventory its overall hydrocarbon assets and to comply with SEC reporting requirements.

The Shell Guidelines first divided petroleum resources into two broad categories: Scope for Recovery ("SFR") and Reserves.

The broad term "SFR" covered hydrocarbon volumes "associated with a project that is not yet sufficiently technically and commercially mature to qualify as reserves."[8] SFR was subdivided into five overlapping categories: SFR Undiscovered, SFR Discovered, Non-Commercial SFR, Commercial SFR by Proved Techniques, and Commercial SFR by Unproved Techniques. All of these resources were conditional resources: they might ultimately mature into reserves but were too premature to be considered "Reserves" as defined below. But Shell nevertheless needed to keep track of and pay attention to them for its own business and capital-investment purposes.

The Shell Guidelines defined "Reserves" as resource volumes "associated with a producing asset or with a project that is technically and commercially mature to the extent that funding for the project is reasonably certain to be secured."[9] These Reserves consisted of Expectation Reserves and Proved Reserves (which Shell in turn divided into Proved Developed and Proved Undeveloped).

- Expectation Reserves were those reserves most likely – even if not reasonably certain – to be recovered from a producing asset or from a project that was both technically and commercially mature. One Shell witness (Christopher Kennett) described Expectation Reserves as the volumes "expected to be producible from a reservoir on a 50/50 basis, at least a 50 percent chance that those volumes that you're going to produce will be equal to or greater."[10] Shell used Expectation

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8 Shell Guidelines dated Oct. 2003 (Doc. #RJW01002434-86).

9 *Id.*

10 Kennett Dep. at 50:16-20.

Reserves to assess its profitability, to rank its projects, to make major investment decisions, and to formulate business plans.[11]

- Proved Reserves were the portion of Expectation Reserves that was "reasonably certain to be produced." This definition therefore was intended to match the definition of proved reserves in the SEC's Rule 4-10.

The Shell Guidelines thus were designed both to produce "proved reserves" estimates that complied with Rule 4-10 and also to capture for business-planning purposes the broader set of resources potentially available for production. Shell committed billions of dollars of its own money to capital projects based on how it categorized its hydrocarbon resources under the standards in those Guidelines.

Because the whole array of potentially available resources was so important from a business standpoint, Shell employees generally did not focus solely on publicly reportable proved reserves when they spoke internally of "booking reserves." Instead, Shell employees often used the phrase "booking reserves" to refer to the full scope of reserves – including all expectation reserves – they were reporting internally to EP management.[12]

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11 *See, e.g.,* Roosch Dep. at 26:3-11; Nauta Dep. at 260:17-261:7.

12 *See, e.g.,* Inglis Dep. at 130:25-132:21; Darley Dep. at 336:25-337:10.

FACT SUPPORT

III. CLASSIFICATION OF HYDROCARBON VOLUMES

A. Oil and Gas Companies are Required to Report Their Proved Reserves in Accordance with SEC Rule 4-10

1. Together, Rule 4-10 and Statement of Financial Accounting Standards ("SFAS") 69 require that public companies with significant oil- and gas-producing activities report their proved reserves and certain related information as supplementary information to their annual financial statements.

a) Barendregt

(1) "The estimation of proved reserves by a publicly traded oil and gas company is governed by SEC Rule 4-10(a) of Regulation S-X, which defines what volumes of oil and gas can properly be designated as proved reserves, and by Statement of Financial Accounting Standards 69, which requires that publicly traded oil and gas companies report their estimates of proved reserves as supplementary information to their annual financial statements." (Decl. ¶ 10)

B. Rule 4-10's "Reasonable Certainty" Requirement

1. Rule 4-10 defines "proved oil and gas reserves" as "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." (Emphasis added) (17 C.F.R. § 210.4-10)

a) Pearson

(1) "In my professional opinion, 'reasonable certainty' denotes a high level of confidence that the reserves will be recovered, but the term also inherently recognizes that reserves are estimates that rely on someone's judgment. Reasonable certainty is the standard to which the judgment should conform." (PBW0010642)

b) Harris

(1) Reasonable certainty "means that a reasonable person's going to expect that this property will produce or be produced. Like I said earlier if it's out in the-- what they

refer to frontier areas, a reasonable person might not expect that if it's out in the middle of the jungle with no pipelines, no infrastructure to produce the properties, a reasonable person wouldn't expect that to be produced." (Dep. pg. 77:14-24)

2. Under Rule 4-10, proved reserves are either developed or undeveloped.

a) "Proved <u>developed</u> oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved <u>undeveloped</u> 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 completion." (17 C.F.R. § 210.4-10.)

C. <u>Shell Adopted Internal Petroleum Resource Volume Guidelines That Were Based in Part on Rule 4-10</u>

1. Shell maintained a set of Petroleum Resource Volume Guidelines ("Shell Guidelines" or "Guidelines") that instructed its operating units in the estimation, classification, and internal reporting of hydrocarbon resources that they controlled. The Guidelines' definition of proved reserves were designed to ensure that operating units' classification and reporting of proved reserves complied with Rule 4-10.

a) Roosch

(1) "I revised the annual Petroleum Resource Volume Guidelines, a group of documents that instructed individual Group operating units on the proper way to estimate and categorize their oil and gas resources and to report those estimates to E&P headquarters. The Petroleum Resource Volume Guidelines were designed, among other purposes, to capture the requirements established by the SEC in Rule 4-10(a) of Regulation S-X for the estimation of oil and gas resources that are designated as 'proved reserves' and 'proved developed reserves.' Pursuant to Statement of Financial Accounting Standards 69, public companies with significant oil- and gas- producing operations, such as the Group's parent companies, Royal Dutch Petroleum Company and The 'Shell' Transport and Trading Company, p.l.c., must include estimates of their proved and proved developed reserves in the supplementary information to their financial statements. Proved reserves are defined as those hydrocarbons that are reasonably certain of being

produced under existing economic and operating conditions." (Decl. ¶ 6)

b) Barendregt

(1) "The Guidelines...instructed the operating units on the estimation of 'proved reserves,' the oil and gas volumes that were reasonably certain of being produced in the future based on existing economic and operating conditions." (Decl. ¶ 9)

2. The principal purpose of the Guidelines, however, was to ensure that EP received accurate information on which to base its planning and expenditure decisions.

a) Barendregt

(1) "The principal purpose of the Guidelines was to ensure that E&P received proper estimates of each operating unit's 'expectation reserves,' the volumes of oil and gas resources that were likely to be produced in the future and on which E&P made its internal business-planning decisions." (Decl. ¶ 8)

D. <u>Shell Classified Hydrocarbons into Several Categories for Internal Business Planning</u>

1. All hydrocarbons within EP's purview were classified as Petroleum Resources.

a) Petroleum Resource Volume Guidelines dated October 2003

(1) "A Petroleum Resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located within the company's current exploration and production acreage." (RJW01002434-86)

(2) "Petroleum Resources are subdivided into two broad categories: Scope for Recovery ('SFR') and Reserves." (RJW01002434-86)

2. Those Petroleum Resources that were not mature enough to be classified as reserves were known as Scope for Recovery ("SFR").

a) Petroleum Resource Volume Guidelines dated October 2003

(1) "SFR is any Petroleum Resource Volume associated with a project that is not yet sufficiently technically and commercially mature to qualify as reserves." (RJW01002434-86)

b) Roosch

(1) "Q. What is an SFR definition? A. Scope for recovery in Shellspeak is that. Q. And what does that mean? A. In industryspeak it would be conditional resources. These are resources that could mature into reserves. Q. But were too premature in the process to know one way or the other. Is that correct? A. Yes." (Dep. pg. 235:21-236:7)

c) Aalbers

(1) "Scope for recovery -- I basically identified hydrocarbon resources that are not yet technically and commercially mature." (Dep. pg. 44:17-19)

d) Van Driel

(1) "Q. You mentioned scope for recovery....What is SFR?... A. If you're talking about resources but you don't know yet if you can commercially produce them or whether they are technically mature, then you flag them as something that could be recovered....If you think of reserves maturation as a funnel, it's the...first step of having reserves, having identified resources." (Dep. pg. 38:6-17)

e) SFR volumes were further subdivided into SFR Undiscovered and SFR Discovered, and into Non-commercial SFR, Commercial SFR by Proven Techniques, and Commercial SFR by Unproven Techniques.

(1) SFR Undiscovered were resources that were contained in undrilled, potential accumulations.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "Resources that could be contained in an undrilled potential accumulation and which would be recoverable by any process that has been demonstrated to be technically feasible elsewhere, under similar conditions." (RJW01002434-86)

(b) Warren

(i) "Those scopes for recovery can in one case be undiscovered volumes, undiscovered scope, as we call it, which has to be discovered through exploration. And that uses a lot of exploration technology to take that undiscovered scope and move it to what's called discovered scope for recovery. That's the exploration piece, if you like." (Dep. pg. 135:12-19)

(2) SFR Discovered consisted of hydrocarbons that had been definitively identified through drilling activities.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "Resources that are contained in an accumulation in which the presence of movable hydrocarbons that are potentially of interest has been established through drilling and, where necessary, through associated data gathering activities." (RJW01002434-86)

(b) J. Bell

(i) "Q. What is scope for recovery? A. I'll give you a simple example. When we drill a well, as we're drilling a well today in Algeria, if we are successful then we have discovered something, and that discovery is something that has scope for us to recover in terms of actual production some years hence. So it enters the books as scope for recovery. Discovered scope for recovery. Prior to drilling we have an assessment of what we might discover and we call it undiscovered scope of recovery. And we progressively move our undiscovered scope recovery through discovered, through development processes into a point where we can actually take an investment decision, and generally at that point, if all the economic tests and SEC tests are satisfied, we can begin to move some of that resource into reserve." (Dep. pg. 62:24-63:14)

(3) Non-commercial SFR consisted of hydrocarbon volumes that were associated with projects that did not pass EP's internal economic-screening criteria.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "Resources that are associated with a project that is evaluated as having a negative Net Present Value...or for which there are clear commercial obstacles to development that appear to be insurmountable in the 5-year plan." (RJW01002434-86)

(b) Graham

(i) "SFR commercial is the project screens economically, and it is -- it is just nonmature in a technical sense. Whereas scope for recovery uncommercial it is nonmature in a technical sense but also it doesn't screen economically." (Dep. pg. 59:7-13)

(4) Commercial SFR by Proven Techniques consisted of volumes that EP could produce using established technical methods at a cost that met EP's economic-screening criteria.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "Resources that are associated with a discovered accumulation and with a project that (a) uses a recovery process or technique which has been demonstrated to be technically feasible in the resource concerned or under analogous conditions and (b) is expected to be Commercial." (RJW01002434-86)

(b) Warren

(i) "There's another scope for recovery which is resources in the subsurface that we know we could move but we have not yet shown it to be commercially feasible. In other words, the technology is feasible, the commerciality isn't. Now, if you understand technology, all technologies go through a price return curve. The more you use the technology the more you learn how to do it more cheaply. And so ultimately if you take a technology you can actually say to yourself if I do this with it I will be able to actually use it commercially, the moment I can do that the scope for recovery will become commercially feasible." (Dep. pg. 135:20-136:10)

(5) Commercial SFR by Unproved Techniques consisted of volumes that EP believed could be economically extracted with methods that had not yet been demonstrated to be feasible.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "Resources that are associated with a discovered accumulation and with a project that uses any recovery process or technique which has not been demonstrated to be technically feasible (under conditions applicable to the area or field) and which requires future laboratory tests and field trials (pilot) in order to establish this feasibility. There must exist the reasonable expectation that, once the necessary work has been completed to demonstrate the technical feasibility of the project, it will be Commercial." (RJW01002434-86)

3. Reserves were defined as hydrocarbons that were associated with a producing asset or with a project that was technically and commercially mature.

a) Petroleum Resource Volume Guidelines dated October 2003

(1) "The term 'Reserves' describes any Petroleum Resource Volume that is associated with a producing asset or with a project that is technically and commercially mature to the extent that funding for the project is reasonably certain to be secured." (RJW01002434-86)

(2) Expectation Reserves were the hydrocarbon volumes associated with the median estimate of ultimate recovery from a field or project.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "The most likely estimate of the Resource Volume remaining to be recovered from a project that is technically and commercially mature, or from a producing asset." (RJW01002434-86)

(b) Roosch

(i) "Q. …What kind of information is expectation reserves based on? A. It's based on all the subsurface information, the properties of the subsurface accumulations. It is based on the development method, how many wells, what sort of wells, what sort of lifting methods, and it is based on what surface facilities, pipelines, any restrictions there. And all that is then simulated and then -- with modern computer tools and it's then ending up as a forecast, and that long-term forecast is then accumulated and is a volume." (Dep. pg. 26:12-23)

(c) Kennett

(i) "Q. What is your understanding of the term 'expectation reserves'? A. Volumes -- Volumes expected to be producible from a reservoir on a 50/50 basis, at least a 50 percent chance that those volumes that you're going to produce will be equal to or greater. So there is a good understanding that you cannot define an exact number in the – for volumes. There's a lot of uncertainty. But the expectation is something like 50/50." (Dep. pg. 50:14-23)

(d) Varley

(i) "Expectation reserve is a P50 estimate….On a cumulative distribution curve, a P50 estimate relates to the volume of which chance there's as much likelihood of the actual value being higher than the number as there is being lower than that number . It's the mid case, if you like." (Dep. pg. 41:20-42:4)

(3) Proved Reserves were defined, in accordance with SEC Rule 4-10, as the hydrocarbon volumes that were reasonably certain of ultimate recovery.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "Proved Reserves are the portion of Expectation Reserves that is reasonably certain to be produced." (RJW01002434-86)

(b) Aalbers

(i) "Reasonable certainty is the definition used by the SEC for booking proved reserves." (Dep. pg. 23:13-15)

(4) Developed Reserves were those reserves that could be extracted by infrastructure that was currently in place or required only minor further investment.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "Developed Reserves are that part of reserves (whether Proved or Expectation) that is producible through currently existing completions, with installed facilities, using existing operating methods." (RJW01002434-86)

(b) J. Bell

(i) "Q. And before you made a distinction between proved developed and proved undeveloped reserves. What is the difference between the two? A. When we take a decision to develop a field, the first thing we do is to design what it is we will develop in terms of facility. We put the facilities on the ground, we start to drill wells. When we have the combination of wells and facilities designed and we've made our commitment to spend on that project, then we have a proved undeveloped reserve. It is only developed once you actually have the holes in the ground and you're actually starting to produce." (Dep. pg. 63:15-64:2)

(ii) "Proved developed reserves are [a] subset of other proved reserves." (Dep. pg. 90:11-12)

(c) Duhon

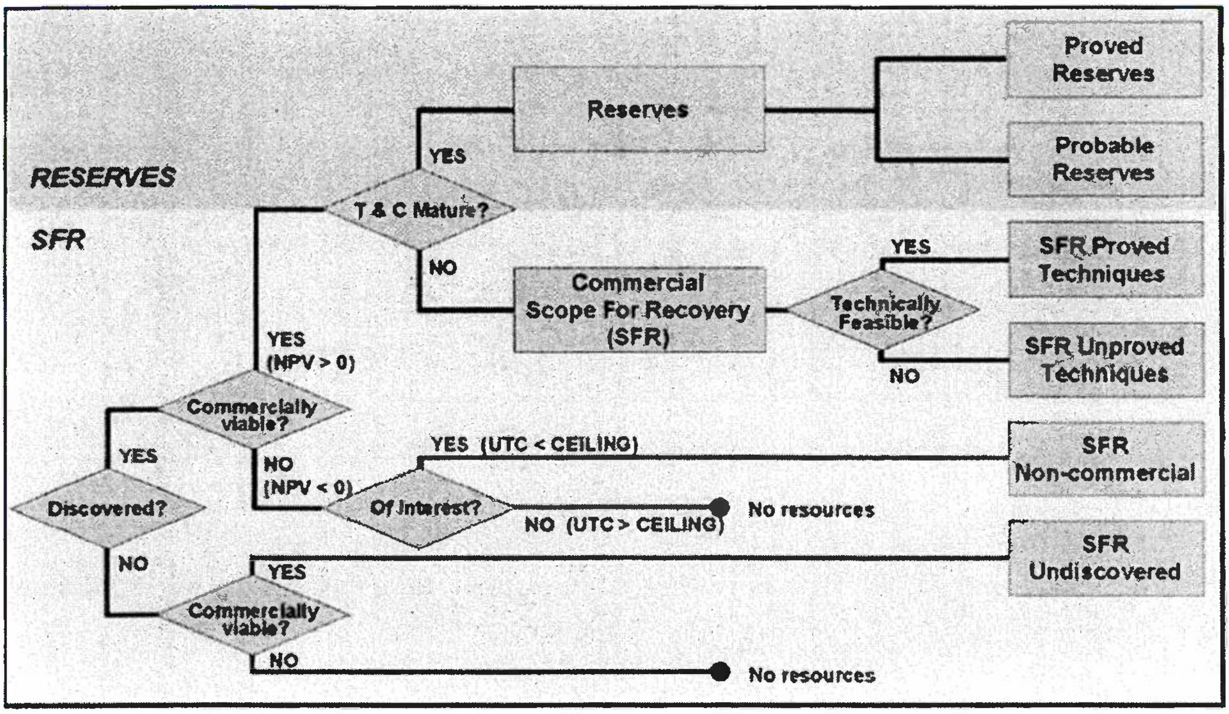
(i) "Proved developed reserves are reserves that are developed, in production. Proved undeveloped have yet to come on stream." (Dep. pg. 23:3-5)

(5) Undeveloped Reserves were those reserves that could not be classified as developed reserves.

(a) Petroleum Resource Volume Guidelines dated October 2003

(i) "Undeveloped Reserves are that part of reserves (whether Proved or Expectation) that cannot be considered Developed Reserves as defined above." (RJW01002434-86)

4. The diagram below, from the Petroleum Resource Volume Guidelines dated October 2003, illustrates the categorizations:



E. <u>EP's Focus Was on Expectation Reserves, Not Proved Reserves</u>

1. EP made investment decisions on the basis of expectation reserves.

a) Ward

(1) "Expectation reserves are the lifeblood of your future growth in the company. Proved reserves are something which are bagged. When you talk about expectation reserves target you're talking about generating resources for future plans and future investment." (Dep. pg. 155:12-18)

b) Warren

(1) "We would have discussed reserves, and I'm now talking about resources and reserves in their largest context, regularly at the BusCom and EP ExCom which it finally became, because that's the blood of our business. As I say, our expectation of reserves are what we actually plan our business around so it's vital. ... I would say at this point that proven reserves have little business significance because we don't develop our oil and gas fields around a concept of proven reserves and we develop them around the concept

of expectations and the uncertainty that we have around those expectations." (Dep. pg. 77:22-78:5, 78:14-20)

(2) "In our industry our concentration is actually on the expectation part of that value chain, because that's actually what we're working with and actually what we make money out of. And that's what the technology is there to support. It's there to enable us to discover oil and gas through seismic, through [provilitry?], through other techniques, including drilling holes and taking measurements from the holes that we put into the subsurface." (Dep. pg. 108:22-109:7)

c) Roosch

(1) "Q. For the record, can you explain what 'expectation reserves' are? A. It is the numbers, the reserve numbers, that commercial corporations use in order to assess their profitability in order to rank their projects, in order to make their investment decision, and in order to project, for their own sake internally, what they're going to earn in terms of money in the future." (Dep. pg. 26:3-11)

d) J. Bell

(1) "The way in which we determine what we will or will not develop is based on expectation reserves. It is not proven reserves." (Dep. pg. 44:1-3)

e) Van Driel

(1) "Q. What are expectation reserves? A. Those are the reserves on the basis of which you make your investment decision." (Dep. pg. 36:17-19)

2. EP Business Plans were formulated on the basis of expectation reserves, not proved reserves.

a) Nauta

(1) "[A]ll that the business planning process is involved with is expectation reserves, investment levels and production levels, as far as volumes is concerned....Changing the booked reserves because they don't meet a particular criterion of the SEC rules for proved reserves does not imply that anything on the platform or the development plan will change. We make our investment decisions on

the basis of expectation reserves not proved reserves." (Dep. pg. 261:3-7, 261:14-24)

b) McKay

(1) "The business is run on expectation reserves...If you were running your business and you wanted to look at trends internally on unit finding and development costs you use expectation reserves because that's the reserves you use for running your business." (Dep. pg. 228:9-10, 228:17-22))

3. Production forecasts were based on expectation reserves.

a) Malcolm

(1) "[E]xpectation reserves are a 50/50 probability. They are based on a middle course on which we therefore base our future production forecast." (Dep. pg. 76:20-23)

4. Shell EP used expectation reserves for these purposes because they reflected the most likely scenario.

a) Platenkamp

(1) "Expectation reserves are the reserves that reflect the most likely outcome if you were to sample ad infinitum the distribution curve of the possible outcomes of all the statistical variations of the parameters that make up the volumetric and recovery distribution of the reservoir." (Dep. pg. 57:23-58:7)

b) Darley

(1) "The most likely or the mid-range estimate, because there are uncertainties around such projections, would constitute the expectation reserves." (Dep. pg. 340:12-15)

F. <u>References to "Booking of Reserves" Did *Not* Typically Refer to SEC Reporting</u>

1. Shell employees used the terms "booking" and "reserves" to refer to the process by which all types of petroleum resources were reported internally.

a) Inglis

(1) "I think we have to be careful about the terminology of booking because some of the explorationists talk about the expectation volumes being booked as meaning that they've

discovered them and that's what they report and saying what our expectation reserves are....[T]he explorationists often talked about booking reserves loosely as meaning the expectation reserves." (Dep. pg. 130:25, 131:2-6, 131:9-11)

(2) "Q. What do you understand booking reserves to mean? A. ...[M]y understanding is that explorationists use that expression to talk about reserves that are captured as the expectation reserves and...nothing to do with the formal process of externally booking proved reserves." (Dep. pg. 132:12-13, 132:17-21)

b) Darley

(1) "We would book proved reserves, we would book expectation reserves. The term 'book' if you like is simply one which indicates that the numbers are being reported." (Dep. pg. 337:7-10)

G. <u>In 2003, EP Created a Reserves Committee to Supervise the Maturation Process</u>

1. The Reserves Committee was made up of the GRC, the Deputy Group Controller and three members of ExCom including the EP CFO.

a) Guide for the Administration of Proved Reserves and Production for External Disclosure (RJW00122186-208)

2. The Reserves Committee had several duties related to the estimation and reporting of proved reserves.

a) Guide for the Administration of Proved Reserves and Production for External Disclosure

(1) Reserves Committee has a duty "[t]o understand, challenge and ultimately to authorize on behalf of the EP Chief Executive Officer the proved reserves figures that are disclosed externally, together with any explanation thereof that is to be published." (RJW00122186-208)

(2) Reserves Committee has a duty "[a]t least annually, to review internal procedures...and the Petroleum Resource Volume Guidelines with a view to determining the need for revision and to direct such revisions where necessary." (RJW00122186-208)

(3) Reserves Committee has a duty "[t]o coordinate relevant correspondence with the United States Securities and

Exchange Commission on behalf of the Group Controller." (RJW00122186-208)

(4) Reserves Committee has a duty "[t]o maintain an interface with external Group Auditors." (RJW00122186-208)

(5) Reserves Committee has a duty "[t]o monitor actions taken by the Regions/Asset Holders or by the EP organization as a whole in response to Group Reserves Auditor recommendations and to inform the external Group Auditors accordingly." (RJW00122186-208)

(6) Reserves Committee has a duty "[t]o assist in the resolution of disagreements between authorizers of proved reserves at different levels in the EP organization." (RJW00122186-208)

3. Barendregt acted as an advisor to the Reserves Committee, which met in the Netherlands.

a) Barendregt

(1) "During 2003, I became a part of the Reserves Committee, a committee within E&P that was established specifically to monitor the Group's oil and gas resource portfolio and to improve the process of estimating and reporting oil and gas resources. The Reserves Committee sat in the Netherlands." (Decl. ¶ 37)

TAB 4

FACT SUMMARY

IV. ESTIMATING PROVED RESERVES: THE ARPR PROCESS

The heart of this case involves Shell's compilation, review, approval, and reporting of its proved-reserves estimates, whose recategorization led to this litigation. The entire process of compiling, reviewing, auditing, and approving Shell's aggregate proved reserves took place in the Netherlands, with inputs of data from operating units around the world. The proved reserves then were reported to the public and the SEC from the Netherlands or the United Kingdom. No part of this process occurred in the United States.

Shell monitored its hydrocarbon resources through an Annual Review of Petroleum Resources (the "ARPR"). The process began in the Netherlands, with the review of the Shell Guidelines and their distribution to operating units around the world. The operating units then reported their hydrocarbon resources to the Netherlands, where they were compiled, reviewed, and approved. The Group Reserves Coordinator (the "GRC"), who was based in the Netherlands, served as the focal point of this process.

A. Review of Shell Guidelines

The ARPR process commenced each year with the GRC's review and revision (where necessary) of the Shell Guidelines. The Group Reserves Auditor (the "GRA"), who also was based in the Netherlands, generally participated in the review and made recommendations to the GRC.[13]

The GRC also circulated the Shell Guidelines to the Netherlands office of KPMG, one of Shell's two external auditors, for its views on the Guidelines' compliance with SEC rules

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13 In one year (2001), the GRA – not the GRC – revised the Shell Guidelines. *See* Barendregt Dep. at 134:7-18.

and regulations. The GRC then submitted the Guidelines to the EP Executive Committee, based in the Netherlands, for approval and endorsement.

B. **Distribution to Operating Units**

Once the EP Executive Committee approved the Shell Guidelines (with any revisions), the GRC sent each operating unit a package containing both the Shell Guidelines and a companion document, "Petroleum Resource Volumes Guidelines: Submissions Requirements for Internal and External Reporting." These Submissions Requirements provided detailed instructions about how the operating units should report their Scope for Recovery, Expectation Reserves, and Proved Reserves to the GRC in the Netherlands.

Operating units bore sole responsibility for estimating and categorizing their hydrocarbon volumes and for reporting them to the GRC. The operating units could – and sometimes did – obtain help from Shell service companies that provided specialized technical expertise unavailable within the operating units. But the operating units themselves remained responsible for making the ultimate decisions about what resources to report to the Netherlands and about how to categorize them.

To make those decisions, the worldwide operating units needed to weigh a host of volumetric, economic, business-planning, and commercial considerations, as required by the SEC's Rule 4-10 and the Shell Guidelines. For example, the operating units had to consider capital-allocation plans, consult with local governments about licensing issues and contractual arrangements, consult with local affiliates of Shell's external auditors, consult with the GRA when he came to perform his audits, and consult with the GRC in the Netherlands. Only then could the operating units send their ARPR submissions to the GRC.

C. **Review and Approval of Operating Units' Submissions**

When the GRC in the Netherlands received the operating units' ARPR reports, he focused on new submissions and revisions that the operating units had proposed. If he had questions about the operating units' proposals, he contacted the units to resolve those issues. The GRC then drafted a report compiling the operating units' proposed reserves estimates (as adjusted, if necessary) into a global reserves estimate for the whole EP business.

The GRA, who also was in the Netherlands, reviewed the GRC's aggregate reserves estimate as well as the individual ARPR estimates submitted by the operating units. The GRA was familiar with various operating units' hydrocarbon resources, because he visited and audited the operating units around the world on a periodic basis. He therefore was able to provide an independent review of the operating units' ARPR submissions.

Based on this review, the GRA issued an opinion about the integrity of the aggregate reserves estimates proposed in the GRC's report. The GRA's opinion, titled "Review of Group End-[Year] Proved Oil and Gas Reserves Summary Preparation" (the "Year-End Review") was sent to Shell's external auditors – KPMG, based in the Netherlands, and PricewaterhouseCoopers ("PwC"), based in England – and to the EP Executive Committee, based in the Netherlands.

A "challenge session" was then held in the Netherlands, to give the GRC, the GRA, the Deputy Group Controller (who was based in London), and the external auditors (KPMG and PwC) a chance to discuss the proposed aggregate reserves estimate that the GRC had compiled and the GRA had reviewed, as well as the GRA's Year-End Review. At the end of this process, the EP Executive Committee in the Netherlands reviewed and approved the proposed aggregate reserves estimate. The proved-reserves portion of that estimate was then published from the Netherlands and England, as discussed in the next section.

In short, the entire process of compiling and approving Shell's reported proved reserves occurred in Europe. None of it occurred in the United States.

FACT SUPPORT

IV. ESTIMATING PROVED RESERVES: THE ARPR PROCESS

A. Introduction to the Annual Review of Petroleum Resources Process

1. The Annual Review of Petroleum Resources ("ARPR") process was conducted for both internal business planning and external reporting purposes. A variety of entities, both internal and external, were involved.

   a) Aalbers

      (1) "ARPR, the Annual Review of Petroleum Resources, is in the process where Shell goes through its reserves estimates annually preparing for the end year reporting of reserves, both internally and also externally, to the SEC and has input into the annual report." (Dep. pg. 65:18-23)

   b) Brass

      (1) "[F]or the reserves process, again the collection of all the data from the Operating Unit comes in at or near the end of the year, that is pulled together by Remco or the equivalent person in that job [the GRC]. He then makes sure that it's, all the corrections and edits are clarified, and reviews it with the likes of a Roelof position, get that input and discusses it with the position I was in [head of EPB]. In that loop the CFO would have gotten involved about at the same time I would. At that point in time our internal review would have been relatively complete. We would have then shown it to the ExCom and gotten any input from them, discussions ....Phil or someone in his position [head of E&P] would be taking their view as to their decisions that need to be made regarding the open issues. Once that is all complete and everyone has reached satisfaction and decisions have been made, then the [letter of representation to the external auditors] is drafted and signed and sent to the auditors....I should mention that there was always a meeting with those auditors and of course, the likes of a Remco and Roelof...and if there's any follow-up questions, et cetera, that occurs." (Dep. pg. 225:19-226:17, 227:24-228:6)

2. A broad range of information was included in the ARPR, which detailed the total volumes in each category of petroleum resources in the particular operating unit's portfolio.

a) Pay

(1) "Q. I think it might be helpful at this point if you can describe briefly what the ARPR process is, how it actually works from its inception to the conclusion of the process. A. Okay. Each operating unit, operating company in the group is required to maintain data on the hydrocarbon resource volumes that it has available within its portfolio and to categorize those volumes....As you drill the wells to discover, as you drill more wells to define the prospect, as you make your development plans and as you execute those plans and bring those assets into production, so the volumes will track through different categories in the system, the categories enabling us to see how mature different elements of the resource portfolio that we have is. So the ARPR exercise...part of that is proved reserves, but it's actually covering the whole resource base. It's essentially a data-gathering exercise where we are required, each of the operating companies to...compile a summary of the resource volumes present in each of the categories, and to provide some detail in terms of the fields in which those volumes were contained." (Dep. pg. 127:2:10, 127:19-128:3, 128:5-13)

b) Van Driel

(1) "Q. What is the ARPR process? A. I understand that to be the process that is all about the reporting of...the resource base of Shell, including proved reserves. Q. What other type of resources bases would that include? A. Expectation, discoveries, as a scope for recovery." (Dep. pg. 36:8-16)

c) J. Bell

(1) "Q. What is the purpose of the ARPR?...A. It allows us to get an overview of the portfolio of your resources. Q. Is there any particular attention to the type of resource, like proved reserves? A. There's attention given to many types of resources, proved reserves being one of them. Q. What other types of resources are looked upon during the ARPR? A. We look at proved reserves, proved developed reserves, expectation reserves, scope of recover, scope of recovery is then broken down into a number of categories." (Dep. pg. 62:8, 62:12-23)

d) Platenkamp

(1) "Q. And what information is included in the submission that is made in connection with the ARPR? A. It's the status of the fields at the end of each calendar year in terms of how many hydrocarbons have been produced and what is left in a number of categories. Q. Does the submission focus on any particular type of resource such as, for instance, proved reserves as opposed to SFR? A. The submission takes the entire spectrum of categories into account. Q. And reports on each of the categories? A. Indeed. Q. What are the categories that are included in the ARPR submission? A. I'm not a specialist, but proved reserves, expectation reserves, and then proved developed, proved undeveloped, scope for recovery, are in general part of that submission." (Dep. pg. 54:22-55:23)

e) Brass

(1) "The reporting of reserves, including but not limited to 'proved' reserves, requires collecting data on Shell's existing hydrocarbon resources from the company's numerous Operating Units around the world. ...Each Operating Unit must report its various categories of hydrocarbon resources, including 'proved' reserves, in accordance with the Petroleum Resource Guidelines, Shell's internal guidelines on reserves reporting." (Decl. ¶¶ 15-16)

B. <u>Group Reserves Auditor Audits of Operating Units</u>

1. For almost all of the period from April 8, 1999 through March 18, 2004 (the "Class Period"), Anton Barendregt was the Group Reserves Auditor ("GRA"), and he was based in the Hague.

a) *See* Barendregt Decl. ¶¶ 1, 5.

2. GRA was responsible for the proved reserves audits of individual operating units.

a) The audits of the operating units typically occurred abroad, in the home country of the operating unit.

(1) Barendregt

(a) "My audits of the reported proved reserves of individual operating units were generally conducted in the country where the operating unit's oil and gas assets were located. For example, my 1999 audit of Shell Petroleum Development Company ("SPDC"), the Group's onshore and shallow-offshore Nigeria operating unit, took place at SPDC headquarters in Nigeria. My contacts for these audits would be personnel in the operating unit who were responsible for overseeing the estimation and reporting of oil and gas resources to E&P headquarters, usually the Chief Reservoir Engineer or Chief Petroleum Engineer." (Decl. ¶ 13)

(2) Barendregt conducted one audit in the Netherlands due to health reasons. (Barendregt Decl. ¶ 14)

(3) Barendregt conducted other audits in The Hague rather than in the country in which the assets of the operating unit were located if the operating unit was based at E&P headquarters. (Barendregt Decl. ¶¶ 15-16)

(4) Barendregt conducted certain operating-unit audits in the United States in cases where there was relevant technical data located in the United States. *See* section IV.B.3 *infra*.

b) The procedures were largely established by Barendregt himself.

(1) Barendregt

(a) "Q. When you first began as the Group Reserves Auditor, did you create an audit program that you followed with regard to conducting the audits of the various operating units? A. Yes. I found that when looking at the reports of my predecessor, that there seemed to be an absence of a sort of a framework along which he would generate or conduct these audits. And even though, of course, I was fully aware that reserves estimating is in the last instance is a matter of opinion taking the Reserves Guidelines as a guiding principle, I still felt that some more structure could be applied. So what I did is I set up a checklist spreadsheet along the -- along the various points in the Reserves Guidelines which would allow me to A, make sure that I had covered all the subjects, all the relevant points in the reserves estimates; but also to have an attempt at scoring the company against that, and thereby get some sore of an aggregate score. I found that a very useful method to be A, consistent, and B, comprehensive in doing my audits." (Dep. pg. 205:20-22, 206:1-22).

c) The audit of an operating unit typically lasted from two to six days.

(1) Barendregt

(a) "Q. Now, just going back to your audits of the various operating units generally speaking, how much time did you spend on an audit? A. Typically two or three to five or six days, depending on the size of the company. The largest one was six days and that was Shell Expro. The smallest one would have been small ventures like Shell at the Port of Brunei where I was for two days." (Dep. pg. 250:17-22, 251:1-3).

d) During the audit of an operating unit, Barendregt would review a sample, ranging from half to three quarters, of the total reserves portfolio of the operating unit.

(1) Barendregt

(a) "Typically in my audits I would cover ... anything between half, maybe three quarters of the total reserves portfolio of that company. So that's how I used to work. You take a few examples, representative examples and I would select them carefully beforehand, and on that basis, you would form an opinion about the soundness of the reserves basis." (Dep. pg. 85:11-19)

e) In conducting the audit, Barendregt reviewed a variety of types of data related to the operating unit's resources.

(1) Barendregt

(a) "I would start about beforehand actually requesting a list of reserves, Proved Reserves and expectation reserves of oil and gas on the basis of which I would select the fields on which I wanted to have a closer discussion....In those discussions, I would typically ask for maps, geological maps, any log data, any panels of log data, which would mean that you put the log data in graphical form next to each other. And as far as those were relevant, I would definitely ask for the mature projects, the producing projects, I would ask for the production performance data, either by field or by reservoir. And normally they would have those available by any ..unit that I would request. So it's those sort of data that I would ask for detailed data; and then I would ask them to explain the field to me, to give me a description of the field, tell me where the challenges of the fields lay, was it low porosity permeability, or was it wells watering out or gassing out, any of those things." (Dep. pg. 251:6-22, 252:1-8)

f) Barendregt used a spreadsheet to score the operating units.

(1) Barendregt

(a) "Essentially, as you will have seen in my report, the method that I used in checking each of these items, is by means of a spreadsheet that I included…in full in my report which gives the various criteria that were dependent – that were important or assessing the quality of the reserves estimates in that particular company. And that would allow me then to add in comments to each of these criteria where they had not [been] so good. I also allowed it to score the company on that particular item." (Dep. pg. 106:12-22, 107:1)

g) Barendregt typically gave the operating unit an opportunity to comment on the draft audit report.

(1) Barendregt

(a) "I liked to strive before leaving, on the last day of my audit, a complete draft of the report that I was going to issue on the auditing question….[U]sually, we then [had] a few days after the end of the audit, I managed to get out a draft report to the company in question for their comments. With that report, I always left instructions to the extent that I said, 'Look, this is my draft report. I want you to go through it and check it on facts – on matters of factual detail; in other words, "Did I get any of the facts wrong? Then please let me know."' Secondly, you can give your opinion about opinions that I have expressed and I will certainly read them. But what I will ultimately do is issue a report that expresses my opinion and my opinion alone." (Dep. pg. 98:9-12, 98:15-22, 99:1-7).

h) In performing his audit, Barendregt applied the Guidelines.

(1) Barendregt

(a) "I would review the procedures and methods in which the reserves estimates have been – would have been prepared, and compare those against the group guidelines, specifically through the spreadsheet that I used in my reports." (Dep. pg. 253:10-14)

(b) "I conducted audits of individual operating units to assess whether their estimation of their oil and gas resources conformed to the requirements of the then-extant Guidelines." (Decl. ¶ 6)

(2) Roosch

(a) "These audits, these retrospective audits, to your understanding were they measured against Shell's internal guidelines? A. Yes. They were. Q. Do you know if they were also measured against the SEC's requirements? A. To my knowledge there was no separate measurements against that because the Shell requirements were deemed compliant with the SEC requirements." (Dep. pg. 85:2-11)

i) KPMG in Europe reviewed the GRA's audit reports.

(1) Barendregt

(a) "Q. What were the reasons for meeting with KPMG three to four times a year? A. It was mostly at their request. They usually took the initiative of asking for a meeting....The main reason, as I saw it, was for them to be able to ask me for any clarification of any audit reports, of any company audit reports that I sent them throughout the year as these audits occurred. So typically I would take anything between six and ten audits a year, and they appeared as I wrote them, as they published and copies were directly sent to KPMG and PricewaterhouseCoopers, and KPMG felt that it would be useful for them to ask for any clarifications from these reports, if they had any questions." (Dep. pg. 61:9-22, 62:1-5).

3. Other than his audit of the U.S.-based operating unit, Barendregt conducted 5 audits of operating units in the United States. In each case, the audit was conducted in the United States because relevant technical data was located there.

a) Barendregt audited the proved reserves for Shell Exploration (China) Ltd. ("SECL") in Houston in 2001 due to the technical work done for SECL by Shell Exploration and Production Technology, Applications and Research ("SEPTAR").

(1) Barendregt

(a) "My audit of SECL in 2001 was conducted in Houston, Texas, because SEPTAR's Houston office was providing technical services to SECL. At all times SECL, not SEPTAR, held the final responsibility for estimating its oil and gas resources and submitting those estimates to E&P. My understanding from my review of the year-end 2003 proved reserves and the recategorization recommendations from Project Rockford is that, although SECL later recategorized certain proved reserves in 2004, this recategorization related to SECL's use of the Group's internal project-screening values rather than year-end prices to calculate its proved reserves entitlements, not to any technical work performed by SEPTAR." (Decl. ¶ 18)

b) Barendregt audited the proved reserves for Shell Nigeria Exploration and Production Company ("SNEPCO") in Houston in 2002 due to the work done for SNEPCO by Shell Deepwater Services ("SDS").

(1) Barendregt

(a) "My audit of SNEPCO in 2002 was conducted in Houston because [SDS], an E&P technical service provider based in Houston, was providing technical services to SNEPCO. At all times, SNEPCO, not SDS, held the final responsibility for estimating its oil and gas resources and submitting those estimates to E&P. Although SNEPCO later recategorized certain proved reserves in 2004, I do not believe that SDS's work was responsible for SNEPCO's reserves overstatement. First, most of the proved reserves that were recategorized by SNEPCO related to the Bonga field, proved reserves for which were first booked before the creation of SDS in 1999. Second, most of the reserves restatement for SNEPCO was due to: (*i*) E&P's decision to report proved reserves for SNEPCO fields before having taken a final investment decision regarding those fields, a decision that was reversed in 2004, and (*ii*) E&P's decision to report proved reserves based on an internal project-screening price rather than the year-end price prescribed by Rule 4-10(a)." (Barendregt Decl. ¶ 19)

(2) Barendregt's audit of SNEPCO's proved reserves is discussed in more detail in Section VII.D.7 *infra*.

c) Barendregt audited the proved reserves for Shell Development Angola ("SDAN") in Houston in 2002 due to the technical work done for SDAN by SDS.

(1) Barendregt

(a) "My audit of SDAN in 2002 was conducted in Houston because SDS was providing technical services to SDAN. Although SDAN later recategorized certain proved reserves in 2004, I understand that SDS's work did not contribute to SDAN's initial reserves overstatement. First, the reserves restatement for SDAN was due to E&P's decision to report proved reserves for SDAN's Block 18 asset before having taken a final investment decision regarding that asset, a decision that was reversed in 2004. Second, SDS's technical work ultimately led to a decrease, rather than an increase, in the amount of reserves that SDAN reported as proved. Third, at all times SDAN had the responsibility for estimating its oil and gas resources and submitting those estimates to E&P. As discussed below, both the GRC and I attended meetings at which the reporting of proved reserves for SDAN was discussed. It was clear at all times that any proved reserves would have to be proposed by SDAN and approved by E&P and by me before being reported externally. For example, it was the GRC and me who suggested to SDAN and SDS that a 'creaming project' targeting only the highest-value resources for initial booking as proved reserves could be pursued and could, according to the Guidelines existing at the time, potentially support a booking of proved reserves." (Barendregt ¶ 21)

d) Barendregt audited the proved reserves for Shell Brazil Exploration & Production ("SBEP") in Houston in 2002 due to the technical work performed for SBEP by SEPCO.

(1) Barendregt

(a) "My audit of SBEP in 2002 was conducted in Houston because SEPCO personnel were providing technical services to SBEP. These technical services, however, related to the Merluza field. I understand that no proved reserves relating to Merluza were recategorized in 2004." (Decl. ¶ 22)

e) Barendregt audited the proved reserves for Pecten Cameroon Company ("PCC") in Dallas in 2003 due to the technical work performed for PCC by Netherland, Sewell & Associates.

(1) Barendregt

(a) "My audit of PCC in 2003 was conducted in Dallas because the Dallas office of Netherland Sewell & Associates had performed study work underlying the PCC ARPR submission. My understanding, however, is that no proved reserves were restated for PCC in 2004." (Decl. ¶ 23)

C. Revision of Guidelines

1. Revision by Group Reserves Coordinator

a) On an annual basis, typically in the fall, the GRC, based in The Hague, would revise the Guidelines and circulate the revised Guidelines to each of the individual operating units.

(1) Aalbers

(a) "Q. Now, how long does the ARPR process last? A. It depends what you call the start of the process versus the end....[I]t basically starts off with updating of the guidelines issuing to the operating units, sending them the...workbooks that they have to fill in and any changes that we've made to those." (Dep. pg. 174:8-15)

(b) "[The revision of the guidelines] normally started after the summer, preparing initially the – the updated guidelines and preparing the – the updates to the [workbooks] that we used and...incorporate all the improvements that I sort of jotted [down] over the last period and thought up over the year, ...and we got those built in to try and build the process on a continuous basis, building in more checks to make sure that errors that people had made in the past were automatically almost caught." (Dep. pg. 187:9-19)

(2) Pay

(a) "Q. What is the Group Reserves Coordinator? A. ...[T]he job did consist of two distinctly different roles. One was the preparation and dissemination of reserves guidelines to the group, with the objective of ensuring that the end-of-year reserves reports from the various group operating companies would be in compliance with the understanding of the SEC regulations. So a responsibility for examining those guidelines, updating them where necessary, where it had become apparent that changes would be necessary, disseminating them, and controlling the whole process of collecting data at the end of the year, data collection exercise that went on from roughly November through 'til January each year." (Dep. pg. 108:19, 108:24-109:14)

(b) "I do recall that guideline documents were issued each year. Each year there would be an update to the previous year's." (Dep. pg. 101:8-11)

(c) "I edited and distributed the Petroleum Resource Volume Guidelines, a group of documents that provided guidance to individual Group operating units on the way to estimate and categorize their oil and gas resource volumes. It also provided instructions to the operating units on the reporting of those estimates annually to E&P headquarters in the Netherlands." (Decl. ¶ 6)

(3) Roosch

(a) "I revised the annual Petroleum Resource Volume Guidelines, a group of documents that instructed individual Group operating units on the proper way to estimate and categorize their oil and gas resources and to report those estimates to E&P headquarters." (Decl. ¶ 6)

(4) Van Poppel

(a) "Q. Do you have an understanding of the term proved reserves? A. Yes, I do....Q. What is the source of your understanding about the meaning of that term? A. The source of the understanding would be the very detailed instructions that are given out by the E&P, exploration and production division, which you refer to as guidelines." (Dep. pg. 82:10-12, 82:23-25, 83:2-7)

(5) Sidle

(a) "The Group Guidelines are prepared, distributed, and revised as necessary by the Group Reserves Coordinator, based in The Hague, the Netherlands." (Decl. ¶ 15)

(6) *See* also J. Bell Decl. ¶ 7, Aalbers Decl. ¶ 6, Brass Decl. ¶ 18.

b) The periodic revision of the Guidelines was designed, in part, to ensure that they remained consistent with the requirements of SEC Rule 4-10.

(1) Roosch

(a) "The Petroleum Resource Volume Guidelines were designed, among other purposes, to capture the requirements established by the SEC in Rule 4-10(a) of Regulation S-X for the estimation of oil and gas resources that are designated as 'proved reserves' and 'proved developed reserves.'" (Decl. ¶ 6)

(2) Pay

(a) "During my tenure, the Petroleum Resource Volume Guidelines were revised annually and were designed, among other purposes, to capture the Group's prevailing understanding of the requirements established by the Securities and Exchange Commission ('SEC') in Rule 4-10(a) of Regulation S-X for estimating oil and gas resource volumes that are categorized as 'proved reserves' and 'proved developed reserves.'" (Decl. ¶ 6)

(3) *See* also Aalbers Decl. ¶ 6.

2. The GRA, similarly based in the Netherlands, also contributed to the revision of the Guidelines.

a) Barendregt

(1) "Q. Did you have any involvement in providing the assumptions that were to be used in any tightening of the guidelines. A. The guidelines in 2002, as I remember it, were put together by Jan Willem Roosch at the beginning of 2002, and indeed I made certain recommendations for corrections in certain parties including this particular issue." (Dep. pg. 579:5-12)

(2) "I commented on and monitored the [Guidelines] that were edited each year by the Group Hydrocarbon Resources Coordinator, also known at the Group Reserves Coordinator." (Decl. ¶ 6)

(3) "I reviewed the Guidelines that the GRC revised and E&P issued each year in order to confirm that the Guidelines would lead the operating units to estimate their proved reserves in a manner that would yield results consistent with the requirements of Rule 4-10(a)." (Decl. ¶ 11)

b) *See* also Brass Decl. ¶ 19.

3. The Guidelines were circulated to KPMG in the Netherlands.

a) Aalbers

(1) "[W]e submitted the draft guidelines to KPMG for the external – that external view on – on whether those guidelines were okay – and basically SEC compliant." (Dep. pg. 188:18-22)

(2) "The updated guidelines were given to KPMG for their – for their review that they were SEC compliant." (Dep. pg. 209:5-7)

b) *See* Brass Decl. ¶ 20.

4. The proposed revisions to the Guidelines were endorsed by ExCom in The Hague.

a) Roosch

(1) "Q. Do the guidelines as revised have to be approved by EP ExCom? A. I had to get them approved by EP ExCom and endorsed. Q. And endorsed. What's the difference between an approval and an endorsement? A. Endorsement means that in my view that these are, by ExCom, the rules that are being proclaimed to the operating units. It was not my place to do that. Q. So acceptance would be that they accepted the versions as presented to them and endorses as this is the set of guidelines that ought to be followed from that point forward. A. Correct. Q. And do you know if EP ExCom approved and endorsed the guidelines as you had revised them? A. That was my understanding." (Dep. pg. 222:12-223:6)

b) Brass

(1) "Any proposed revisions to the guidelines were…submitted to the EP Executive Committee, also located in The Netherlands, for approval and endorsement." (Decl. ¶ 21)

5. United States-based entities and personnel were, in general, not involved in the revising of the Guidelines. Rod Sidle, a reservoir engineer in the United States, made comments concerning drafts of the Guidelines for the principal reason that Shell Exploration and Production Company ("SEPCO"), the EP operating unit in the United States, had its own set of hydrocarbon-classification guidelines that needed to be reconciled to each new version of the Shell Guidelines.

a) Leonard

(1) "I am not aware of any personnel from the Houston EPB office who assisted in drafting or revising the Shell Guidelines in any way during my tenure as VP of NBD." (Decl. ¶ 13)

b) Roosch

(1) "At all times during my tenure as interim GRC…E&P personnel in the Netherlands were responsible for and carried out the editing and issuing of the Petroleum Resource Volume Guidelines." (Decl. ¶ 12)

c) Barendregt

(1) "Although I occasionally discussed the Guidelines and the requirements of Rule 4-10(a) with Rod Sidle, a reservoir engineer employed by [SEPCO], E&P's United States operating unit, the GRC was always responsible for revising and played the principal role in revising the Guidelines. Personnel from E&P would occasionally consult with Sidle concerning reserves-related matters, but the primary purpose of involving Sidle was to help him ensure that SEPCO's policies and practices for estimating and reporting proved reserves were consistent with Group practices. The final decisions concerning the content of the Guidelines were always made by the GRC or other E&P personnel located in the Netherlands." (Decl. ¶ 12)

d) Sidle

(1) "Q. Who was responsible for attempting to harmonize the SEPCO guidelines with the group guidelines? A. Largely that was me. Q. Could you describe the process by which you attempted to accomplish that harmonization? A. Okay. You've indicated the first step, and that is simply read them, and then talk to the people that understood them within the group, who typically was the reserves coordinator, so that I had a good understanding for what those words meant and how they were administered. Then I looked at our own processes to see where the things we were doing either exactly aligned with, or Shell practices were within what was allowed by the group. I looked at places where there might have been some issues of difference and then tried to resolve those. Q. Do you recall who at the group you spoke to, what individual you spoke to in connection with your effort to harmonize the SEPCO guidelines and the group guidelines? A. Yes. When that first started, the reserves coordinator was Remco Aalbers." (Dep. pg. 39:18-40:19)

(2) "I did review the group guidelines. I offered my personal view. Knowing how that they should be applied -- how the SEC meant they should be applied in international situation was not an area of my background or experience. So what I did was look for where there were SEPCO issues and tried to provide specific instruction there, to make sure that SEPCO's practices that had been well established were able to fit within the framework of the group guidelines, and then beyond that simply provide whatever information I

had, because I was on SPE committees and had access to other industry information, to help the group, whoever was preparing the document, have that as information that they should -- they could use when they put the rules together. As long as I had given them all the information I had, I relied on them to make the judgments as to how Shell's interpretation of those rules to be used internationally fit with the requirements." (Dep. pg. 139:3-23)

6. After the Guidelines had been approved, EP distributed them from The Hague to the operating units around the world.

a) In October or November the GRC would circulate a package to each OU containing the *Petroleum Resource Volumes Guidelines: Submissions Requirements for Internal and External Reporting* (the "Submission Requirements"). The Submission Requirements provided detailed instructions for the submission of each OU's expectation and proved oil and gas reserves.

(1) Petroleum Resource Volumes: Submission requirements for internal and external reporting dated October 2000 (PER00081361-98); Petroleum Resource Volumes: Submission requirements for internal and external reporting dated October 2001 (RJW01001010-54); Petroleum Resource Volumes: Submission requirements for internal and external reporting dated October 2002 (RJW01002352-95); Petroleum Resource Volume Guidelines: Submission Requirements for Internal and External Reporting dated November 28, 2003 (HAG00011282-328)

(2) Barendregt

(a) "The second part is the – is the instructions for use of the tables that operating units had to submit to the center at the end of the year. So it's more of a how to input the figures type of explanation rather than the method ... in determining the volumes of the actual volumes of the reserves." (Dep. pg. 222:9-15)

(3) Pay

(a) Referring to his role in the Denmark OU: "So each year we would usually receive an update to the group's guidelines, group's reserves reporting guidelines, which would cover proved reserves also, as well as requirements of reporting volumes in every other category in the classification system that we were speaking about earlier, and my job would be to read and absorb those guidelines, understand them, and then apply the, those guidelines to the volumes that we estimated to be available within the business in Denmark." (Dep. pg. 89:5-15)

(b) Referring to his role as GRC: "Not necessarily everybody everywhere has access to fancy database systems, so the spreadsheet approach was the way we took, so we would [send] out a blank template to everybody with all the required fields in there, data fields that we would ask to be filled in, and the companies would compile their estimates, sign off, and submit those estimates to us, using the Excel workbook." (Dep. pg. 129:5-13)

(4) *See* also Brass Decl. ¶ 21.

D. Estimation of Hydrocarbon Resources by Operating Units

1. General responsibilities.

a) Operating units themselves were responsible for determining the volumes of hydrocarbons for their own areas and reporting this to EP in the Hague. Although they may have received input from EP personnel working in service organizations, operating unit personnel signed off on and submitted the operating unit's ARPR.

(1) ARPR submissions to EP were signed by operating unit personnel.

(a) Year-end 1999 ARPR for Venezuela SVSA (RJW00400910-34); Year-end 1999 ARPR for Nigeria SNEPCO (RJW00400629-46); Year-end 1999 ARPR for Oman PDO (RJW00400823-31); Year-end 2000 ARPR for Venezuela SVSA (RKW00402111-40); Year-end 2000 ARPR for Oman PDO (RJW00401726-34); Year-end 2000 ARPR for Angola SDAN (RJW00400979-1005); Year-end 2000 ARPR for Nigeria SNEPCO (RJW00401617-49); Year-end 2001 ARPR for Oman PDO (RJW00070771-82); Year-end 2001 ARPR for Angola SDAN (RJW00060075-103); Year-end 2001 ARPR for Venezuela SVSA (RJW00072630-41); Year-end 2001 ARPR for

Nigeria SNEPCO (RJW00070678-706); Year-end 2002 ARPR for Oman PDO (RJW00082043-77); Year-end 2002 ARPR for Nigeria SPDC (RJW00080407-48); Year-end 2002 ARPR for Nigeria SNEPCO (RJW00080376-404); Year-end 2002 ARPR for Angola SDAN (RJW00080583-608); Year-end 2002 ARPR for Kazakhstan SKD (RJW00080191-215); Year-end 2002 ARPR for United Kingdom EXPRO (RJW00082370-401); Year-end 2002 ARPR for Australia SDA (RJW00080719-58); Year-end 2002 ARPR for Iran SEBV (RJW00080143-57); Year-end 2002 ARPR for Norway NSEP (RJW00080450-66); Year-end 2002 ARPR for Brunei BSP (RJW00081688-701); Year-end 2002 ARPR for Malaysia SSB (RJW00080217-37); Year-end 2002 ARPR for Venezuela SVSA (RJW00082414-27)

(2) Kennett

(a) "No entity based in the United States and no United States-based personnel played any role in compiling PDO's ARPR or assisted PDO or me in estimating PDO's proved reserves. PDO's ARPR was never submitted to or from the Untied States." (Decl. ¶ 10)

(b) "During my employment at BSP, the process of compiling BSP's ARPR was conducted entirely from BSP's headquarters in Seria, Brunei." (Decl. ¶ 20)

(3) Brass

(a) "Upon receiving the approved internal guidelines, each Operating Unit was responsible for determining the volumes of petroleum resources in its region in accordance with the internal guidelines and for reporting those figures to the Group Reserves Coordinator in The Netherlands." (Decl. ¶ 22)

(b) "[E]ach Operating Unit itself bore ultimate responsibility for making its own independent determinations about its reserves and for reporting that information to the GRC." (Decl. ¶ 25)

(4) Inglis

(a) "SDAN was responsible for making reserves submissions for its assets, including the calculation and reporting of 'proved' reserves. SDAN bore sole responsibility for its annual submissions to EP headquarters in The Netherlands as a part of Shell's Annual Review of Petroleum Resources ('ARPR'). ARPR submissions for SDAN were signed every year by SDAN personnel in Angola or The Netherlands and submitted to the Group Reserves Coordinator in The Netherlands." (Decl. ¶ 8)

(b) "SDAN made the final decisions regarding its reserves submissions." (Decl. ¶ 9)

(c) "In addition to commissioning and supervising the technical services provided by SDS, SDAN performed additional tasks that were necessary to SDAN's reserve submissions, including the reporting of its 'proved' reserves. Such tasks essential to the SDAN Angola ARPR process included the economic screening of projects. Thus, even though the SDS team dedicated to Block 18 performed preliminary volumetric estimates and rudimentary cost analysis, SDAN performed the economic and commercial analysis necessary to calculate 'proved' reserves. As such, SDS did not determine the quantity of 'proved' reserves that were submitted to EP headquarters in the Netherlands for internal and external reporting purposes." (Decl. ¶ 11)

(5) McFadden

(a) "Upon receipt of SDS's forecast and models, SNEPCO gave them to its economics and planning group located in Lagos, Nigeria. The economics and planning group ran economics using the terms of the production sharing agreement to calculate Shell's entitlement share of the proved reserves for the fields in which SNEPCO owned an interest. The computed Shell entitlement share was given to my department, the petroleum engineering group, also located in Nigeria. The petroleum engineering group shared the data with the chief reservoir engineer in Nigeria, who collated the data and prepared the ARPR report for SNEPCO." (Decl. ¶ 13)

(b) "The reservoir engineer then sent me SNEPCO's draft ARPR. After reviewing the report in Nigeria, I sent it to the Group Reserves Coordinator, who worked at E&P headquarters in the Netherlands." (Decl. ¶ 14)

(c) "SNEPCO itself, not SDS, determined what volumes SNEPCO would report as proved reserves." (Decl. ¶ 17)

(d) "[T]he economics were run by the economics and planning group. The cost data was QC'd and controlled through the development/planning group. And my group looked at the forecasting data, but then took the final number and reported those in the ARPR report." (Dep. pg. 69:3-8)

(e) "Q. After you received the forecasts back from SDS, what was done with that data or information at SNEPCO? A. That data was then passed on to the economics and planning group, together with the cost data that we would get through our – the development/planning group in SNEPCO. They would run economics using the terms of the PSC to calculate the Shell entitlement share under the PSC, and that was the number which we reported in the, in the ARPR." (Dep. pg. 71:25-72:10)

(6) Roosch

(a) "During my tenure as interim GRC, each operating unit undertook the task of estimating it own oil and gas resources and reporting those estimates to E&P headquarters." (Decl. ¶ 7)

(7) Hoppe

(a) "During the entirety of my employment by SPDC, the process of compiling and submitting SPDC's ARPR was performed solely at SPDC's headquarters in Nigeria." (Decl. ¶ 14)

(b) "SNEPCO also prepared its own ARPR and submitted it to the [GRC] in the Netherlands." (Decl. ¶ 15)

(8) Barendregt

(a) "SDAN held the final responsibility for estimating and reporting its oil and gas resources....SDAN and E&P, not SDS, made the final decision concerning whether SDAN could properly report proved reserves for its assets." (Decl. ¶ 28)

(b) "The operating units themselves were responsible for estimating, compiling and submitting their resource volumes. While some operating units received technical assistance from service providers such as SEPTAR and SDS, this assistance was designed either to allow the operating unit to estimate its subsurface oil and gas volumes and map the structures of subsurface reservoirs more accurately or to enable the unit to develop ways to improve its production of hydrocarbons in the subsurface. Once this technical work had been performed (either by a technical service provider or by the operating unit itself), the operating unit needed to conduct the necessary economic, legal, and contractual analysis to determine the appropriate volumes of resources to report to E&P for each category in the ARPR." (Decl. ¶ 31)

(9) S. Bell

(a) "During my employment at [Shell Development Australia ('SDA')], the process of compiling and submitting SDA's ARPR was directed from SDA's corporate headquarters in Australia, with input from the Group Reserves Coordinator's office in The Hague, the Netherlands. No part of SDA's ARPR was compiled in or submitted from the United States." (Decl. ¶ 8)

(10) Pay

(a) "During my tenure as GRC, each operating unit was responsible for estimating and categorizing its own oil and gas resource volumes and reporting those estimates annually to E&P headquarters in the ARPR report....Only the operating unit itself could and did make the final and critical determination concerning whether it was correct to report any proved reserves for an asset and, if so, the volume that would qualify as proved reserves." (Decl. ¶ 7)

(b) "Only the operating unit itself had the responsibility and authority to submit, and did submit, the ARPR containing the estimates of its oil and gas resource volumes, including proved and proved developed reserves, to E&P headquarters." (Decl. ¶ 8)

(11) *See* also J. Bell Decl. ¶ 8, Aalbers Decl. ¶¶ 7-8.

b) OUs were also responsible for ensuring that their submissions were compliant with the Shell Guidelines.

(1) Aalbers

(a) "The operating units have to make sure that they determine the reserves for the individual OUs in line with the – with the group guidelines and report them according to the...guidelines to the center. And they have to make sure that when they report their financial information, that that is in line with what they are reporting as reserves so that they use the same reserves for depreciation as they report that year in terms of annual reporting." (Dep. pg. 176:5-14)

(b) "The OUs will report on the basis of the internal guidelines and – which then, if they follow that, according to the guidelines, by default makes them compliant to the SEC reporting." (Dep. pg. 177:10-14)

(2) Brass

(a) "Each Operating Unit must report its various categories of hydrocarbon resources, including "proved" reserves, in accordance with the Petroleum Resource Guidelines, Shell's internal guidelines on reserves reporting." (Decl. ¶ 16)

(3) Roosch

(a) "[T]he operating unit was held responsible for performing the critical analysis necessary to determine whether those hydrocarbons were reasonably certain of being produced under existing economic and operating conditions, and therefore were appropriate to report to E&P headquarters as proved reserves consistent with Rule 4-10(a)." (Decl. ¶ 7)

(4) Pay

(a) "[T]he operating unit would take into account the full range of conditions set out in the Petroleum Resource Volume Guidelines, paying due regard in particular to the legal and contractual regimes under which the operating unit functioned." (Decl. ¶ 7)

2. Categories of data in submissions.

a) The data submitted by the OUs included, among other categories of information, all types of volumes (including scope for recovery, expectation reserves, and proved reserves).

(1) S. Bell

(a) "I coordinated the process by which SDA compiled and submitted its ARPR to Shell's E&P headquarters in the Netherlands. The ARPR contains the year-end summary of a Shell company's oil and gas resources, broken down into categories such as proved reserves, expectation reserves and scope for recovery." (Decl. ¶ 6)

(2) Hoppe

(a) "The ARPR contained the year-end summary of SPDC's oil and gas reserves in all categories for both internal and external reporting purposes, as well as other related data." (Decl. ¶ 13)

(3) Brass

(a) "Operating Units were required to divide their petroleum resources into various categories of hydrocarbon resources, including proved developed reserves, proved undeveloped reserves, and scope for recovery." (Decl. ¶ 23)

(4) *See* also Barendregt Decl. ¶ 29.

b) The Submission Requirements required OUs to complete spreadsheets containing various data, including:

(1) Detailed estimates of scope for recovery reserves, with designations for type of reserves (gas, oil, or natural gas liquid), license applicability, type of revision where applicable, etc.

(2) Summaries of resources by field for each type of resource (oil/ngl or gas)

(3) Relevant Exploration Wells for the time period in question

(4) Chart of expected exploration discoveries and revisions for internal reporting

(5) Summaries of historical exploration discoveries

(6) Detailed estimates of proved reserves for external reporting purposes

(7) Summaries of major changes to proved reserves

(8) Statistical data related to acreage and number of wells drilled

(9) Charts of cash flow input ("PSC & Innovative Contracts")

(10) Petroleum Resource Volumes: Submission requirements for internal and external reporting dated October 2000 (PER00081361-98); Petroleum Resource Volumes: Submission requirements for internal and external reporting dated October 2001 (RJW01001010-54); Petroleum Resource Volumes: Submission requirements for internal and external reporting dated October 2002 (RJW01002352-95); Petroleum Resource Volume Guidelines: Submission Requirements for Internal and External Reporting dated November 28, 2003 (HAG00011282-328)

(11) Brass

(a) "In addition to reporting the volumes of the various categories of petroleum reserves, Operating Units had to provide data about other matters such as cash flow, drilling activities, and licensing issues." (Decl. ¶ 24)

c) The Submission Requirements also provided instructions on the use of a computerized workbook for inputting the data.

3. Typically OUs nominated an employee whose specific responsibility it was to handle the ARPR process, and a senior manager was responsible for signing off on the submission.

a) Barendregt

(1) "Q. Now, at the operating unit level, who is responsible for signing off on the reserves that are reported to the center? A. In my days, it was the chief petroleum engineering manager, so typically the same position as I was holding in Lowecroft." (Dep. pg. 215:17-22, 216:1)

b) Aalbers

(1) "For the [ARPR] cycle, all reservoir engineers have to, at the end of the year, prepare updated reserves numbers that then get reported to the reserves coordinators who then sort of roll that up to company totals. So you would report the...proved, the expectation, the potential scope for recovery, the changes that have been there throughout the year from the previous estimate that was made the year before." (Dep. pg. 61:22-62:7)

(2) As Reserves Coordinator, his "[d]uty was collating the end year total reserves for NAM and reporting those...to the center." (Dep. pg. 43:16-18)

c) Pay

(1) Regarding Brunei: "[T]here was a...focal point who is required – whose job it was to compile the data, but as in all operating units, the data report would be signed off by a senior financial manager and a senior technical manager within the company." (Dep. pg. 82:20-25)

(2) "Q. Who were the focal points, what was the job position you're referring to? A. These were typically depending on the size of the operating unit that would either be a full-time position within the operating unit. For the larger ones, person whose specific task within the operating unit was to manage the hydrocarbon reporting, volume reporting process for their operating unit." (Dep. pg. 262:25-263:9)

d) Roosch

(1) "Q. While you were at some of the OUs such as PDO, do you recall being involved in the ARPR process? Let's take PDO as the example. A. I was insuring that we had the right to guiding rules, and I was signing off on the numbers. Q. And in signing off the numbers you mean signing off on the reserves that you understood could be booked as proved. A. Correct." (Dep. pg. 229:17-230:6)

e) Graham

(1) Testified that she, as reserves coordinator of SDA, was responsible for the ARPR – a process she described as collecting the data from the operators, applying "an economic and commercial overlay," and then preparing the actual submission document (an Excel spreadsheet). (Dep. pg. 35:2-4)

f) Kennett

(1) "I was essentially responsible for deciding what reserves would be reported for the year in BSP's ARPR, subject to review by Mr. Straub, who was located in Brunei, and by the Group Reserves Coordinator and EP Executive Committee in The Hague." (Decl. ¶ 19)

g) Varley

(1) "Sean McFadden, SNEPCO's Chief Petroleum Engineer who was worked at SNEPCO's headquarters in Lagos, Nigeria, was responsible for coordinating and did coordinate reserves-related issues at SNEPCO, including the preparation and submission of SNEPCO's [ARPR]." (Decl. ¶ 11)

(2) "McFadden was responsible for reserves-related issues in SNEPCO. He was the reserves focal point." (Dep. pg. 97:23-25)

h) McFadden

(1) "Well, I basically supervised the reservoir engineers who worked on [the ARPR] and ensured that we were getting the right data that we required from, from the group doing the modeling in Houston, and also that we were getting the right data from partners that we needed to input in that. I also liased [sic] with the development planning group

because the reserves calculation process for the PSC invoices putting – running economics and inputting cost data as well in the economic model to get an entitlement share, which is the number that's reported at the end of the day. So there was a number of various different sources of information that went into the reserves – in the final reserves number and different people who were involved in the calculation." (Dep. pg. 68:12-69:2)

(2) "While employed by SNEPCO in Nigeria, I was responsible for the work of the petroleum engineering group, which participated in ....the [ARPR]." (Decl. ¶ 11)

i) S. Bell

(1) While employed by SDA in Australia, I coordinated the process by which SDA compiled and submitted its [ARPR] to Shell's E&P headquarters in the Netherlands." (Decl. ¶ 6)

j) *See* also Platenkamp Dep. pg. 50-51.

4. The operating units themselves were responsible for interacting and did interact with foreign governmental entities concerning the estimation and reporting of proved reserves within that government's jurisdiction.

a) Kennett

(1) "As Head of Reservoir Engineering and as Chief Petroleum Engineer of Offshore West in BSP from 1999 to 2003, I met with the Petroleum Unit of the Brunei government every year in November, in Brunei, to discuss BSP's reporting of reserves in its ARPR submission." (Decl. ¶ 17)

b) McFadden

(1) "With SNEPCO, yes, we did talk to Government officials. We talked to people, particularly in the DPR which was a regulatory group, because well proposals had to be discussed with -- approved by the DPR. The DPR had to approve field development plans. So we were involved in a number of presentations to the DPR involving presenting field development plans and well proposals. Q. Can you just tell me what DPR stands for, if you know? A. Department of Petroleum Resources." (Dep. pg. 31:15-25)

5. The submissions were subject to review by the GRC and GRA and in certain circumstances were revised based on the results of that review.

   a) For example, in the year-end 2001 ARPR process, Roosch testified that the operating units' original submissions were altered by the ARPR process, i.e. altered by the various entities and individuals who reviewed the submission.

      (1) Roosch

         (a) "Q. As a result of the ARPR process, do you recall if the numbers that were publicly reported by Shell with regard to proved reserves were lower than the numbers that you saw at the start of the process? A. You mean the estimates that were on the table at the start of the process?...Yes they were lower. Q. And generally can you tell us the reasons why the numbers were lower? A. We found a number of reserves changes that we had a feeling that could not be supported." (Dep. pg. 148:19-149:12)

6. The regional business directorates assisted the operating units within their region with the operating units' submissions.

   a) Aalbers

      (1) "The initial challenge would be with the local reserves coordinator and, in some cases, depending on what the issue was, the regional business advisor would be involved in the challenge process." (Dep. pg. 110:3-7)

      (2) "[T]he regional business directors are responsible of [sic] their respective areas, so if there would be an issue with any specific reserves booking for a specific country, that ... would be escalated through the regional business advisor, and the regional business director would get involved." (Dep. pg. 181:11-17)

   b) Barendregt

      (1) "[W]hen Shell Angola wanted to propose a reserves addition for their Block 18 fields, there was some doubt expressed, in the first instance by Remco Aalbers, who was the group reserves coordinator, as you know, supported by myself. I had my doubts too. And we were both taken aback by the aggressive reaction that we received from the organization, particularly from staff in Shell Development Angola, even more so in the regions, in the regional

business directorate in The Hague....I think on balance, the most vocal were probably the people in the regional business directorate." (Dep. pg. 358:6-16, 359:2-4)

7. Both operating units and personnel from the regional business directorates consulted the GRC concerning the operating units' ARPR submissions.

a) Aalbers

(1) Recalls communicating with an RBA concerning the decision to debook Abu Dhabi reserves. (Dep. pg. 247:5-249:2)

b) S. Bell

(1) "[T]he process of compiling and submitting SDA's ARPR was directed from SDA's corporate headquarters in Australia, with input from the Group Reserves Coordinator's office in The Hague, the Netherlands." (Decl. ¶ 8)

c) Kennett

(1) PDO's ARPR submission was prepared with oversight by Shell's GRC, who was based in The Hague. (Decl. ¶ 9)

d) Roosch

(1) "I served as a resource to the Group's operating units as they estimated their oil and gas resources." (Decl. ¶ 6)

e) Barendregt

(1) "Operating units often consulted with the GRC concerning whether a proposed categorization of oil and gas resources was consistent with the Guidelines." (Decl. ¶ 31)

E. Review of Submissions by Group Reserves Coordinator

1. The GRC reviewed OU submissions.

a) The GRC, based in The Hague, was responsible for collating all operating-unit submissions and compiling the numbers from each operating unit into the annual Reserves Report.

(1) Roosch

(a) "Q. Was it the responsibility of the GRC and his team to review all of those various submissions? A.

Well, to some extent, but one could expect that the submissions would be completed staff work. Q. And what was the role then of the GRC and the GRC staff in connection with the ARPR process? A. To do the checks that there was integrity, that the spreadsheets were checking all right, and to make sure that things were as they were meant to be submitted." (Dep. pg. 36:4-16)

(b) "The operating units submitted their individual ARPRs to my office in the Hague and I aggregated the ARPR estimates into overall estimates of E&P's global oil and gas resources." (Decl. ¶ 8)

(2) Aalbers

(a) The role of the GRC is "taking the data that are supplied by – for this specific role, by all the operating companies around the world and then basically adding those up and preparing the right reports with all the right delta analysis and that sort of stuff." (Dep. pg. 72:23-73:4)

(b) "The job [of GRC] was a combined role between group reserves reporting and as a principal economist…So the understanding was that for the period sort of from the end of the year till, I don't know, maybe say, November, December, running with a peak in January or February, be responsible for making sure that all the data was rolled up and the reporting requirements were fulfilled." (Dep. pg. 85:10-19)

(c) *See* also Aalbers Decl. ¶ 6.

(3) J. Bell

(a) "The GRC would compile all of the estimates from the operating units, scrutinize and challenge these estimates if necessary, and calculate aggregate estimates of proved and expectation reserves for all of EP. These aggregate estimates were then presented to the ExCom, the executive body of the EP business that sat in The Hague, for approval." (Decl. ¶ 8)

(4) Barendregt

(a) "After each operating unit submitted its ARPR to the GRC in the Netherlands, the GRC compiled that information into an aggregate estimate of the Group's oil and gas resources. The GRC also made a preliminary determination concerning whether the operating units' reported oil and gas resource numbers were appropriate." (Decl. ¶ 32)

(5) *See* also Pay Decl. ¶ 6, Brass Decl. ¶ 26.

b) The GRC's review of the ARPRs focused on new submissions and revisions.

(1) Roosch

(a) "[T]here is of course a couple of things that the changes attract our attention. We look at the changes. Q. Such as? A. Certain upward revisions greater than, and certain new submissions. There is also a comparison with what is expected. ...Q. When you say 'submissions at a greater than,' what are you referring to, greater than what? A. Anything substantial. We didn't have a rule for that, but anything that was more than a couple of million BOE would attract our attention." (Dep. pg. 39:3-17)

(2) Aalbers

(a) "We were looking at...whether or not the – the major changes were in line with the group guidelines and that the explanation of the changes actually made sense and whether or not we felt that they ... met the technical commercial maturity criteria that we needed to report the reserves. Q. And when you say 'major changes' what are you referring to?...A. Major changes would be bookings of new fields that hadn't been booked before that were significant within the reporting of any specific OU...[W]e looked at both, the proved, the expectation, the scope, the exploration history." (Dep. pg. 107:14-108:12)

2. The GRC communicated with the operating units.

a) The GRC would work with the relevant operating unit to resolve questions about particular submissions.

(1) Roosch

(a) "To do the checks that there was integrity, that the spreadsheets were checking all right, and to make sure that things were as they were meant to be submitted. So there would be some to and fro between the reserves [sic] coordinators and the operating units and my group." (Dep. pg. 36:13-18)

(b) "I was informed that Mr. Aalbers made a trip to PDO at the time that PDO did a considerable reserves increase. Q. And what was the result of that trip[?] A. That guidelines were left behind and instructions along which people could work and could justify, according to the then in force guidelines, that there was a considerable increase in proved reserves." (Dep. pg. 237:2-11)

(2) Pay

(a) Referring to his involvement, as GRC, with the SPDC submission: "So I guess the nature of my investigation was to challenge or to ask questions of the people submitting this data in SPDC, together with the people compiling the reserves data, to try and probe, understand better the basis, the foundation for the projected production increase." (Dep. pg. 157:13-19)

(3) Aalbers

(a) "Q. Now, how would you go about, from the EP end challenging a submission from an OU? ...A. It's partly understanding the – EP business and what was happening throughout the year. So certain things that [you knew] had taken part throughout the year, you would expect to see back in the reserves submissions. And if you wouldn't, then there's obviously something not right. And in some cases, numbers reported in different elements of the submission just wouldn't hang together ....And we were trying to get that sort of consistent logic throughout the reporting....Q. When you engaged in this challenge process, who did you speak to at the OU level? A. The initial point of contact is normally the local reserves coordinator in the OU who actually does the submissions, so the challenge would normally run through them." (Dep. pg. 108:18-109:16)

(4) Brass

(a) "[W]hen the reports [from the operating units] first started coming in, [Aalbers] would be on the phone constantly, because, of course, to really clarify questions on an OU, the only people that can really help with that are the people in the Operating Unit." (Dep. pg. 234:15-19)

3. The GRC would identify any important issues that needed the attention of the head of EP's New Business Development division ("EPB"), who was located in the Hague.

a) Brass

(1) "Remco and Roelof would bring me highlights and issues. His total summary eventually, of course, gets digested down into what goes into the Annual Reports and the 20F, and the actual internal document on the Reserve Report was not something that I, that I recall getting or receiving in wide distribution. It was a massive display of numbers ... from all the world, so what we reviewed was really a summary of that, along with any issues." (Dep. pg. 235:2-12)

(2) "The [GRC] was part of my organization, and the GRC function maintained its offices in The Netherlands. I reviewed the GRC's work as part of Shell's annual review of its hydrocarbon resources." (Decl. ¶ 9)

4. The GRC drafted a report to ExCom summarizing the operating-unit submissions.

a) Pay

(1) "Q. Now, going back to the process, you've described effectively the role of the operating unit. You've described the role of the Group Reserves coordinator. When the process had concluded, did that information then get run up the flag pole, if you will to the ExCom? A. Yes. Q. And how did that information go from your office to the

ExCom? A. I wrote a brief report, explaining the, the previous year's performance in terms of proved reserves additions, proved reserves changes, and the reserves replacement ratio for the year, which is the parameter by which such things are measured, so I wrote a brief two page report summarizing the changes, the reserves replacement ratio and the year-end balance." (Dep. pg. 138:22-139:14)

b) Roosch

(1) "I...provided or presented the aggregate estimates of the entire Group's oil and gas resources to several parties, including...[Excom], which sat at E&P headquarters in the Netherlands and needed to approve the aggregate estimates of oil and gas before they could be finalized and reported to the public." (Decl. ¶ 6)

c) *See* also Brass Decl. ¶ 27.

F. Review of Submissions by Group Reserves Auditor

1. The GRA in The Hague provided an independent review of the operating-unit submissions.

a) Barendregt

(1) "There are three activities that the Group Reserves Auditor carries out...The second one is to witness and audit the process of accumulating reserves at the end of the year, and that is taking place in the center." (Dep. pg. 243:4-5, 243:9-12)

(2) "I think at this point it's useful to bear in mind – to remember that my role- one of my roles was to report to E&P management and to external auditors at the end of the year just before the external reserves were going to be published." (Dep. pg. 50:6-10)

(3) "I evaluated whether, on an aggregate level, the Group's estimate of its total proved oil and gas reserves was fairly presented and whether the total estimate was properly derived from the estimates of the operating units." (Decl. ¶ 6)

(4) "Each year, I evaluated whether E&P's estimate of its proved reserves was consistent with the requirements of the Guidelines, and therefore with the requirements of applicable law. My evaluation, contained in a report called

the Review of Group End-[Year] Proved Oil and Gas Reserves Summary Preparation ("Year-End Review"), was one of the many steps in the process by which the Group compiled and reported its proved-reserves estimates." (Decl. ¶ 29)

(5) "I reviewed both the GRC's aggregate estimate of the Group's proved and proved developed reserves and the individual estimates from the operating units. My review was designed to confirm that: (*i*) the GRC had properly aggregated the proved reserves estimates of the individual operating units; (*ii*) the operating units whose reserves estimates I had audited during the previous year had properly taken my observations and comments into account in making their submission; (*iii*) any significant changes in an operating unit's reported proved reserves were properly supported; and (*iv*) any other important questions concerning the propriety of an operating unit's proved reserves were addressed." (Decl. ¶ 33)

b) Pay

(1) "Mr. Barendregt was present in the office and took a role in reviewing the submissions of the reserves reports from the different operating companies within the Shell Group around the world. He would be a part of the process of reviewing the submissions and would take a, if you like, an independent view as to their veracity and reasonableness. So my job was to essentially compile the figures that were submitted. His job was to provide an independent review of the figures that had been submitted." (Dep. pg. 21:22-22:8)

(2) "My observation of what he did, so what I observed him doing...certainly as a result of the visits that he would have made to operating companies during the year, he would clearly be looking for evidence that any recommendations that he had made as a result of those visits would have been implemented, was one of the things....He made some, shall we say, consistency checks that the numbers that were reported as of the end of year X were consistent and could be audited....He would on occasion ask for clarification of the numbers that had been submitted if he felt that was necessary, and I would say they were the main activities." (Dep. pg. 23:18-24:6, 24:11-14)

(3) "Q. If you can just briefly describe what the GRA role was

in the ARPR process. A. To take an independent view of the submissions that had been provided by the operating units; to ensure that he understood or that there was adequate explanation for the changes that were registered there; to verify that, where there were known issues arising from the audit visits that he had made in that year or in prior years, that any recommendations he had made had been acted upon and the results of those recommendations were reflected in the numbers that were submitted; and, through a process of questioning, to satisfy himself that the group guidelines had been adhered to, generally, in the preparation of the data." (Dep. pg. 147:6-20)

c) Van Driel

(1) "Q. Where was [Barendregt] located? A. One floor up from where we were." (Dep. pg. 121:20-21)

d) *See* also J. Bell Decl. ¶ 9, Roosch Decl. ¶¶ 6, 8 & Dep. pg. 82:16-18, Brass Decl. ¶ 28.

2. The GRA's review included analysis of compliance with the Guidelines.

a) Aalbers

(1) "The role of the group reserves auditor was to check that the OUs reported their reserves, both the proved and the expectation, in line with the group guidelines, and he basically was responsible to provide the technical assurance for KPMG in their process of review the – the reserves numbers." (Dep. pg. 177:19-25).

b) Pay

(1) "[W]e had the group guidelines for the preparation of proved reserves, and if reserves were submitted – reserves estimates were submitted, that he would satisfy himself that those estimates had been prepared, if he felt it necessary, in conformance with the Group Guidelines....My understanding was that he reviewed the submissions in relations to the group's guidelines, which were themselves implemented or written in a way that would allow the SEC proved reserves regulation to be implemented in our own business context." (Dep. pg. 30:11-17, 30:21-25, 31:2)

c) Brass

(1) "The GRA reviewed the proposed reserves volumes for compliance with Shell's internal guidelines." (Decl. ¶ 28)

3. The GRA coordinated his review of the ARPR submissions with the GRC.

a) Roosch

(1) "Q. Did you have any communications with Mr. Barendregt during the ARPR process? A. Yes. Q. And what was the sum and substance of those communications? …A. I asked him advice on certain things….Certain changes that I would have a problem with I would ask him about that. And of course he had a rich file of retrospective audit reports on several OUs that I then could consult." (Dep. pg. 65:21-66:5-12)

(2) "Q. You mentioned that you sought advice on certain things from Mr. Barendregt. Do you recall on what topics you sought advice?…A. I sought advice. Yes. Q. Do you recall the topics what [sic] you sought the advice on? A. Yeah, a number of field cases. Usually it had to do with change because we were very keen on any changes to make sure that they were, indeed stabilized and in keeping with the rules as we saw them. Q. And these changes you're referring to are the changes when – were increases? A. There were increases. Yes. Q. Do you recall which OUs you sought his advice on? A. I probably requested him about the Angola case. Q. What was the issue with Angola? A. The Angola group was submitting an increase and, as I said before, every significant increase I would look into to see, indeed, that it would stand scrutiny and it would be in keeping with the Rule 4-10 reasonable certainty. And this was one of the cases where I wasn't entirely sure that this was in keeping with the rule under reasonable certainty, and I discussed the case with Mr. Barendregt." (Dep. pg. 66:20-67:25)

4. The GRA circulated annual reports, which were distributed to EP personnel and the external auditors, all of whom were located in Europe.

a) The GRA then drafted a *Review of Group End-XXXX Proved Oil and Gas Reserves Summary Preparation* (the "GRA Annual Report"). The GRA Annual Report included, where possible, a verification of the reasonableness of major reserves changes.

(1) Barendregt

(a) "I would prepare a report which KPMG and PricewaterhouseCoopers did receive, and I would prepare a presentation that they attended to and at which they could ask as many questions as they liked. Q. In the report that you prepared, is this the annual report? A. Yes indeed, yes. My annual report, yes." (Dep. pg. 50:16-22, 51:1-2)

(b) "After reviewing the ARPR data submitted by the operating units, I composed the Year-End Review. The Year-End Review discussed (*i*) the results of the individual operating-unit audits that I had conducted during the previous year, (*ii*) other notable issues concerning the operating units' ARPRs, such as a significant change in an operating unit's proved reserves, and (*iii*) any observations that I had concerning changes that needed to be made to the Guidelines to ensure that operating units conformed to both the spirit and the letter of applicable law in estimating their proved reserves." (Decl. ¶ 34)

(2) Pay

(a) "[Barendregt] would produce a report which would be provided to internal management and also our external auditors in relation to essentially providing a statement, providing his opinion with regard to the...proved reserves figures that had been reported." (Dep. pg. 24:14-19)

(b) "I know as part of the process, once the figures had been compiled, the Group Reserves Auditor submitted a report on the end-year figures to the external auditors...and a meeting was held at which the Group Reserves Auditor presented his findings on the end-year compilation figures." (Dep. pg. 148:19-25)

(3) *See* also J. Bell Decl. ¶ 9.

b) The GRA's Annual Reports concluded with an "overall finding from the audit visits and from the end-year review" as to whether the SIEP summary "fairly represent[s] the Group entitlements to Proved Reserves" and whether the changes in the summary "can be fully reconciled from the individual OU submissions." A detailed list of findings and observations was attached.

(1) Review of 1998 proved oil and gas reserves (RJW00751053-61); Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (V00280131-44); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (LON01260652-66); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (V00300308-20); Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (V00010650-66); Review of Group End-2003 Proved Oil and Gas Reserves Summary Preparation (RJW01021058-76)

c) The GRA's Annual Reports were circulated, usually in late January or early February, to various members of EP and the external auditors.

(1) Barendregt

(a) "I submitted my Year-End Review to the E&P leadership and to the Group's external auditors, KPMG and PricewaterhouseCoopers." (Decl. ¶ 35)

G. Review by External Auditors

1. The external auditors, located in Europe, also reviewed the ARPR submissions.

a) The external auditors were involved both locally in assisting with OU submissions in the country where the operating units were situated and in subsequent review of submissions in the Hague. KPMG occupied offices at EP headquarters during its review.

(1) Aalbers

(a) "It's actually a parallel process where KPMG get involved as of the point where the reserves are being submitted by the operating units to the center. ...For the OUs that we were happy with submission data, those would get provided to – to KPMG, who would then do their checking of those numbers, basically comparing it to prior years, see if the changes made sense, look at trends." (Dep. pg. 121:5-8, 121:19-23)

(2) Pay

(a) "[R]epresentatives of the external auditors were given office accommodation in our office building and sat with us as the returns were coming in; would review the returns that were coming in, and compile – essentially do checks that, first of all, the submissions from the OUs themselves were internally consistent, I would say, purely from a numerical point of view, that the numbers added up; and also in the way that we compiled those returns into a group statement and individual regional statements, that those compilations faithfully reflected the numbers that were in the individual company submissions, operating company submissions." (Dep. pg. 148:2-15)

(3) Brass

(a) "Q. Did you have any interaction yourself with representatives from either KPMG or PwC while you were the head of Strategy, Planning and Business Development at E&P? A. Yes....Q. Did you meet with these people on regular basis? A. Really annually, and that was as a result of the process of bringing the Reserve Report together. They would talk very regularly with the likes of Remco or Roelof and also would talk with the CFO, who at the time was Dominic Gardy, but I would usually talk with them really when nearly all of the...detailed work had been accumulated." (Dep. pg. 74:23-75:23)

(4) Van Driel

(a) "Q. [To your knowledge,] did KPMG maintain an office in the same building? A. As far as I can remember, yes, they did." (Dep. pg. 86:24-97:2)

(5) Van Poppel

(a) "One of the tasks performed by the Dutch KPMG affiliate's (KPMG NV) Group audit team was the review of the proved reserves estimates that EP compiled during its [ARPR] for disclosure in the supplementary information to the financial statements in Shell's Annual Report on the Form 20-F filed with the Securities Exchange Commission." (Decl. ¶ 8)

(b) "As part of their review process, I understand that KPMG NV representatives had working space in Shell's offices in the Hague for their review." (Decl. ¶ 9)

(6) Roosch

(a) ARPRs "were passed on to the outside auditors, who then got the opportunity to – to query." (Dep. pg. 59:19-23)

(b) *See* also Roosch Decl. ¶ 6.

b) The external auditor review focused on changes and internal consistency.

(1) Aalbers

(a) "[KPMG] would check the factual correctness of the final submissions rolling into the totals, so literally the accountancy trying to check that every number is exactly the same, there's no changes anywhere between what is submitted and what goes into the total, and also checking whether or not the – the changes that they're seeing make sense and can be properly explained." (Dep. pg. 125:9-16)

(2) Roosch

(a) "Q. When [the outside auditors] came to the office to discuss, you said to question some of the justifications, were these in the nature of a challenge, much like the challenge sessions that occurred at Shell, or were they more in the nature of a general inquiry? A. It was more a challenge, I would say….Q. What happened after they challenged and obtained information? Do you recall if they were satisfied? A. In general. It could be case where, indeed, their query would lead to certain adjustments. (Dep. pg. 61:9-16, 62:21-25, 63:2)

(b) "Q. Well, what kind of information did they review?…A. I seem to remember this was numerical information. Q. And it was the information that came from the OUs? A. Correct." (Dep. pg. 64:23-65:7)

(3) Van Poppel

(a) "KPMG NV checked the mathematical correctness of the final proved reserves estimates. The external auditors also checked the proved reserves estimates for consistency with prior submissions and ensured that any changes in proved reserves volumes were properly explained." (Decl. ¶ 10)

c) The external auditors used the GRA's report as input to their work.

(1) Van Poppel

(a) "Through his detailed reviews and reports, [the GRA], in the Netherlands, was responsible for providing PwC and KPMG with the outcome of, among other things, the technical reservoir engineering aspects to assist in their review." (Decl. ¶ 11)

2. Discussions occurred between the GRC and external auditors during the ARPR process.

a) Roosch

(a) "There is an established procedure as we got completed submissions in that we were happy with. They were passed on to the outside auditors, who then got an opportunity to…query. Q. Other than passing on the information, did they ever come in and interact with either you, Mr. Wharton, Mr. van Driel? During this ARPR process, this three-week period we've been talking about, do you recall them coming into the office and talking to you? A. Yes. …Twice weekly, three times perhaps. Q. Do you recall the nature of their visits?" Was it to obtain information, data? Was it to discuss the information? A. They were copied on the information, and they came into the office to discuss questions they had and justifications as to why these volumes would change." (Dep. pg. 59:19-23, 60:4-22)

b) Van Driel

(1) "Well, in the course of the ARPR, I would meet with the external auditors from KPMG." (Dep. pg. 77:18-19)

(2) "Q: Do you recall what work KPMG was doing in the ARPR?" A….I can describe the interface that I had with them. I don't know what work they've all done during that meeting….So, largely that would have been that KPMG was also working somewhere in the building on the information that we provided about the ARPR, and they would come at some point from some date onwards. When we felt the date [meant data?] that was getting more stable, they would come with clarifying questions." (Dep. pg. 79:3-7, 79:10-16)

3. The external auditors made presentations of their findings in Europe.

a) Aalbers

(1) "Q. Now, was that a separate meeting where KPMG would sort of present their findings? A: Yes. Q. Okay. And – and, typically, where was that held? A. When I joined, it was typically in London….[B]ut when Anton Barendregt came, we actually would have had the meeting in The Hague." (Dep. pg. 126:25-127:9)

4. The external auditors also attended the annual reserves challenge meeting in The Hague (see below).

a) Barendregt

(1) "Q. After the booking was made in December of 2000, did you haven any discussions about the booking with the external auditors? A. Yes. They saw all my reports. We must have discussed it, and they must have asked some questions. Q. Do you recall when you had these discussions?…A. [In] January as part of the closeout of the year, yes." (Dep. pg. 394:6-13, 395:17-18)

b) Van Poppel

(1) "Q. Did representatives of both outside auditors attend that meeting each year? A. They did indeed. Q. Do you know whether any information was provided to the outside auditors in anticipation of that meeting?…A. They would have looked at the returns that would have been prepared by the local operating companies on reserves figures." (Dep. pg. 90:15-22, 91:2-5)

5. KPMG issued a letter of assurance each year from the Netherlands.

a) At the conclusion of their participation in the ARPR process each year, KPMG authored a letter of assurance to be used by Shell in the external reporting process.

(1) KPMG Letters of Assurance, dated February 24, 1998 (V00100377-87); February 9, 1999 (KNV0006347-77); February 2, 2000 (V00010027-38); February 26, 2001 (V00100481-503); February 4, 2002 (V00100537-55); February 12, 2003 (KNV0000001-85)

H. Annual Reserves Meeting

1. After circulation of the GRA's Annual Report, an annual "challenge session" was held in The Hague, attended by the GRA, GRC, the Group Deputy Controller, individuals from EPB, and the external auditors. None of the attendees was based in the United States.

a) Nauta

(1) "There were informal sessions, not all of them with Lorin Brass, but certainly with John Bell, and there was a closeout presentation at the end of the whole cycle where the results were also presented to the -- to the auditors and to representatives from the Shell group because it was a piece of work that would ultimately result in an external disclosure....Q. This closeout presentation, is this a presentation that you recall attending? A. Yes. Q. Who else attended the presentation? A. I can't remember the -- all the names of the individuals, but it would have included the line that we were reporting into, Lorin Brass and John Bell, external auditors, and a representative from the group controller, group controller's office. Q. Who was the representative from the group controller's office? A. That would have been Hans van Poppel." Q. Did Mr. van Poppel serve in that position throughout your tenure as head of capital allocation and global planning? A. I think he did, yes. Although he may have retired toward the back end of my tenure. Q. And I take it from your career history on Exhibit 1, you were involved in one ARPR process? A. Yes. Q. Is that correct? A. Yes. Q. And that would be in the year 2002 for the prior year 2001? A. That's right. Q. Now, in this closeout presentation, you said it would include the external auditors. Who are you referring to? A. KPMG." (Dep. pg. 168:16-170:17)

b) Van Poppel

(1) "Q. So who typically attended these meetings? A. It would be…myself and the person in the group reporting section that would look after reserves figures that were going to be included in the annual report. It would be the head of the department responsible for the reserves reporting figures, and the representative of the external audit firms." (Dep. pg. 103:7-17)

(2) "These challenge sessions all took place in the Hague, which is the seat of Shell's EP business." (Decl. ¶ 12)

(3) "Other attendees included representatives from PwC and KPMG, the [GRA], the [GRC], and occasionally members of EP management or other EP staff responsible for compiling the reserves figures." (Decl. ¶ 15)

c) Barendregt

(1) "[A] meeting would be held in The Hague to discuss the proved reserves figures that the Group proposed to report externally. I attended the meeting, as did the GRC, one or more E&P personnel who supervised the GRC and representatives from KPMG, PwC, and the Group Controller's office. None of the attendees was based in the United States. At this meeting, the GRC would present the Group's proposed proved reserves figures…to KPMG and PwC. I would present the results of my review and my opinion concerning whether the proposed proved reserves figures fairly presented the Group's entitlement to proved reserves. KPMG and PwC were able to, and did, ask clarifying questions concerning any issue about which they were uncertain." (Decl. ¶ 35)

2. The purpose of the annual reserves challenge meeting was to review the proposed reserves figures to be reported publicly and provide the external auditors with the opportunity to ask questions of the GRA or the EPB reserves reporting group.

a) Van Poppel

(1) "The purpose of that meeting was that the Reserves Auditor presented his annual report, and [the] reserves reporting group presented the figures that were going to be reported." (Dep. pg. 102:17-21)

(2) "[The challenge session gave] Group Finance as well as the external auditors from PwC and KPMG an additional opportunity to review and challenge the proved reserves data that EP proposed to include in Shell's Annual Report on the Form 20-F." (Decl. ¶ 12)

b) Brass

(1) "Before the EP Executive Committee issued its final approval of Shell's reported proved reserves, a 'Challenge Session' was held in The Hague. The Deputy Group Controller (who was based in The Netherlands), KPMG NV, PWC and additional EP-B representatives reviewed the reserves data with the Group Reserves Coordinator and the Group Reserves Auditor and had an opportunity to challenge the GRC's and the GRA's determinations." (Decl. ¶ 31)

c) Barendregt

(1) "KPMG and PwC were able to, and did, ask clarifying questions concerning any issue about which they were uncertain." (Decl. ¶ 35)

3. At this meeting, the GRC presented on the Group's year-end proved and proved developed oil and gas reserves and the GRA presented his conclusions (both used PowerPoint slides). During and following these presentations, there were discussions regarding the appropriateness of particular booking decisions.

(1) Aalbers

(a) "Q. Now, what role, if any, did the deputy group controller have in the ARPR process? A. He was involved in the...final meeting where the reserves got cleared to be published ultimately." (Dep. pg. 179:13-18)

(2) Pay

(a) "Q. What was your interaction with the external auditors during the process? A. In terms of the process that took place, it was daily interaction during which I would, or my assistant would provide the auditor's representatives with the latest information that we had available as the returns were coming in, and that those auditor representatives would take that information away, do some form of consistency checking, that the figures added up." (Dep. pg. 149:25-150:12)

(3) Van Poppel

(a) "Q. What types of information would [Aalbers] convey in his presentation? A. More or less a summary of the figures that were going to be reported for inclusion in the 20-F. And the relevant analysis thereof." (Dep. pg. 105:19-24)

(b) "The annual reserves meeting included presentations by the Group Reserves Coordinator and the Group Reserves Auditor, Anton Barendregt. These presentations typically were accompanied by PowerPoint or view-graph presentations. The challenge usually lasted about half a day." (Decl. ¶ 17)

(c) "PwC and KPMG appeared to follow the presentations closely and asked questions to obtain additional insight. If PwC or KPMG had any issues with Mr.Barendregt's reports, they asked for more background. PwC and KPMG also asked questions of the Group Reserves Coordinator, including queries about the status of fields, molecules, licenses, and proved gas volumes." (Decl. ¶ 20)

4. Following this meeting and the subsequent discussions, the external auditors prepared a report that was presented to the Committee of Managing Directors ("CMD"), typically in February, and then to the Group Audit Committee ("GAC") in March. The most important matters to emerge from the challenge meeting would be discussed by the External Auditors in their report to the GAC.

a) Brass

(1) "At the conclusion of the ARPR process, KPMG NV issued a statement on the results of its review of Shell's reserves which it delivered to PwC and KPMG in London. KPMG NV completed all of this work in The Netherlands and delivered its statement of results to Shell Transport in the United Kingdom and Royal Dutch in The Netherlands." (Decl. ¶ 31)

I. Letter of Representation

1. After the "challenge session," Shell provided a "letter of representation" to KPMG and PriceWaterhouseCoopers ("PwC"). The letter was signed by the EP CFO and the head of EPB, both of whom were located in the Hague.

(1) Letters of Representation dated February 5, 1998 (RJW01000668); February 9, 1999 (RJW00151432-34); February 1, 2002 (LON00010021).

(2) Pay

(a) "[The letter of assurance] was a letter signed each year as part of the compilation of the reserves statement for form 20F. It was signed by, in this case it would have been signed by Mr. Coopman, the chief financial officer, and Lorin Brass, the director, with responsibility for preparing those numbers. And it was a letter to, I believe, the external auditors KPMG and PricewaterhouseCoopers to the effect giving their approval of the numbers and/or endorsement of the numbers that had been compiled." (Dep. pg. 335:4-14)

(3) Brass

(a) "Q. What was your involvement with respect to reserves when you were the head of Strategy, Planning and Business Development [at] E&P[?] A. The Reserves Coordinator was in my organization, and through his activities, which were the collection of the reserve information globally, we coordinated the Reserve Report, and in that process I, along with generally either the CEO or the CFO, would sign the Letter of Representation regarding reserves to the auditors, to the External Auditors." (Dep. pg. 68:16-69:2)

(b) "In reliance upon the expertise of the GRC, the GRA, and other experts within my organization, I signed the annual Letter of Representation to Shell's external auditors about Shell's reserves." (Decl. ¶ 10)

2. The purpose of the letter of representation was to give an endorsement of the reserves numbers.

a) Brass

(1) "Q. What was the purpose of that letter? A. To share with the auditors our view of the status of the reserves for the prior year, whether there was any questions, whether there was any issues, et cetera, but it's a letter...to tell them our view of the reserves for 1999." (Dep. pg. 77:24-78:6)

(2) "The Letter of Representation endorsed the reserves numbers for the year." (Decl. ¶ 10)

b) Pay

(1) "And it was a letter to, I believe, the external auditors KPMG and PricewaterhouseCoopers to the effect giving their approval of the numbers and/or endorsement of the numbers that had been compiled." (Dep. pg. 335:10-14)

3. In signing the letter, the head of EPB relied on the expertise of the GRC and the GRA on reserves issues and the oversight provided by KPMG.

a) Brass

(1) "Q. And in Item Number 2 [of the Letter of Representation to External Auditors in February of 2001] says that '[t]he information has been properly prepared and disclosed in accordance with SFAS 69 and SEC Rules and Regulations, and as clarified by subsequent SEC staff accounting bulletins and interpretive guidance issued by the SEC.' Were you relying on any particular individuals to confirm that the information had been properly prepared in accordance with the SEC Rules and Regulations? A. Yes. Q. And which individuals were those? A. Primarily Anton and Remco." (Dep. pg. 225:3-14)

(2) "I consulted with the [GRA], experts within my organization, and Shell's external auditors, KPMG NV, about Shell's proved reserves. The GRA, KPMG NV, and the experts with whom I consulted all were based in The Netherlands. In reliance upon the expertise of the GRC, the GRA, and other experts within my organization, I signed the annual Letter of Representation to Shell's external auditors about Shell's reserves during this time period. The Letter of Representation endorsed the reserves numbers for the year." (Decl. ¶ 10)

J. Approval of Proved Reserves by ExCom

1. The submissions were reviewed by the head of Planning in EPB (such as J. Bell). The head of EPB (such as Brass) then oversaw the creation of a presentation to ExCom, first as a Note for Information or Note for Discussion, and second as a PowerPoint presentation. The presentation was given by Brass's immediate subordinate (such as Platenkamp).

a) J. Bell

(1) "Q. Going back to the ARPR, did you -- other than the team that worked on the ARPR, did you have any role in the ARPR? A. No. I had a management role, but I had eventually a role to review the product of the team before we submitted it up our management line to my boss and to the CFO who were the two people that took it then into the EP Executive Committee." (Dep. pg. 66:8-15)

(2) "Q. Do you recall the form in which information was presented to the ExCom in connection with the ARPR? A. The form I believe [was] two-fold. One would have been a Note for Information and Discussion, and secondly, a PowerPoint presentation. Q. Which came first? A. The Note for Information would normally come first, and it would be part of the prereading for the EP ExCom." (Dep. pg. 85:6-15)

b) Brass

(1) "Q. And what role did ExCom play? A. Every year ExCom was given a presentation on the results of the accumulation of the reserve data for the prior year. Q. And what was your role with respect to that presentation, now that you were the head of Strategy, Planning and Business Development [of] Exploration and Production? A. I would have been the reviewer of the presentation. Q. And who was responsible for giving that presentation? A. In January in 2000, Roelof was....Q. Was that standard for his function? A. Yes. Q. Now, when you say you would have been a reviewer of the presentation, would you have reviewed the presentation prior to it being made? A. Yes. Q. And would you have reviewed the presentation around the same time as you reviewed the report from Remco Aalbers? A. In about the same time frame I would have reviewed the report from Remco prior to the review of the presentation." (Dep. pg. 81:8-82:9)

(2) "Q. Who was responsible for creating the presentation materials? A. I think I mentioned earlier that my review of the presentation came from Roelof, so of course, I looked to Roelof to develop the presentation." (Dep. pg. 121:17-22)

(3) "I...provided high-level supervision of the reserves reporting and classification process." (Decl. ¶ 7)

(4) "From 2000 (when I became head of Strategy Planning and Business Development for EP-B) until 2003, the reporting of oil and gas reserves fell under my supervision." (Decl. ¶ 8)

(5) "I reviewed the GRC's work as part of Shell's [ARPR]." (Decl. ¶ 9)

c) Nauta

(1) "Q. You say there was a presentation at the end of the ARPR process. When is that presentation given? A. As I recall it, it would have been sometime in February. I can't remember the exact date. Q. Now, is there a report of some sort of document like the one we're talking about right now which is Exhibit 2, that is prepared at the conclusion of the ARPR process?...A. It's called the ARPR. Q. Okay. A. It's a ring binder, it's big book with lots of graphs and numbers. Q. Is it one book or is in multiple books? A. It's one book. As far as I remember, yes. Q. And who is the book presented to? A. To Lorin Brass, who then presents it to the ExCom, sponsors it to the ExCom." (Dep. pg. 167:7-18, 167:22-168:11)

d) *See* also Roosch Decl. ¶ 8.

2. ExCom played an active role in determining what reserves were booked.

a) The presentation to ExCom was a summary of the proposals for reserves submissions by the operating units. ExCom had the ability to affect the final numbers and booking decisions.

(1) Platenkamp

(a) "Again, here we have to understand that Shell companies cannot book reserves. It's only Shell that can book reserves....Shell Development Australia can make a recommendation and say this is what we believe that you can book on our behalf." (Dep. pg.

163:17-24)

(2) Aalbers

(a) "And basically…the total reserves will get reported to ExCom either as these other numbers and there's no issues, or if there were a number of issues, then a number of issues would have to be – would have to be tabled with a recommendation on what we thought was the right way to go, and obviously, ExCom then could either choose or not chose to follow that recommendation. I think…that's the main involvement that they had. …In a number of cases where it couldn't be resolved and it actually needed…a senior decision on whether or not to turn left or right or however you compare it, yes, then it would – it went to ExCom." (Dep. pg. 181:19-182:4, 182:16-20)

(3) Brass

(a) "[After the Annual Reserves Meeting,] [t]he Executive Committee was then given an additional opportunity to revise the submissions at a subsequent meeting." (Decl. ¶ 30)

b) In 2001, for example (with respect to reserves from year-end 2000), ExCom deliberated on whether to book particular reserves.

(1) Brass

(a) "Q. [W]ere there issues that were brought to ExCom in January of 2001 pertaining to any of the items discussed in Anton Barendregt's report? …A. Well, the big ones there were again how to handle bookings in some big chunks. Iran. We talked about Athabasca. There was also the suggestions to cap the proved reserves in Nigeria, Abu Dhabi, those kind of things.…We talked about Angola in great detail and had come to a decision on Angola." (Dep. pg. 278:24-279:3, 279:17-21, 280:4-5)

3. The Group Deputy Controller in London verified that the production figures reported in the reserves reports were consistent with the other production reports.

(1) Van Poppel

(a) "There was one important check made and that was the check whether the figures that were reported as production figures were in agreement with the figures that were reported by the reserves figures as production." (Dep. pg. 56:5-10)

4. When ExCom was created, formal signoff of the reserves figures by the head of EP was implemented.

a) Aalbers

(1) "As we moved to ExCom and…the reporting roles of the different directors changed, it was felt at some point by…finance that the head of EP had to formally sign off on the reserves before they could be published." (Dep. pg. 114:23-115:4)

(2) "Q. Did you have any interaction with Philip Watts in connection with the signoff? A. For that one signoff [for year-end 2000] we had a – sort of a teleconference…with Mr. Watts and…Dominique Gardy and myself….Q. Okay. Do you recall if the proved reserves figures for year-end 2000 were discussed? A. That was what the conference was on….The reserves get reported beforehand to ExCom, …and they had been supported by the – by KPMG and by the group auditor, so all sort of the steps in the process had been taken and had been closed out. So it was just the final signature on the final document." (Dep. pg. 116:22-25, 117:2-3, 117:22-24, 118:18-23)

b) *See* also Brass Decl. ¶ 29.

K. <u>Inclusion of Proved Reserves in Annual Report and Form 20-F</u>

1. After the EP CEO's final signature, no changes were made to the reserves figures reported. The figures, after final checks were made, were translated for inclusion in the annual reports.

a) Aalbers

(1) "Q. What happened – once [Phil Watts] signed off on the numbers…what happens next in the process?" A. Well, ultimately the reserves get rolled into the annual report…and the 20F that gets reported to the SEC. Q. So the numbers – to your knowledge, the numbers that Mr. Watts signed off on, those get reported publicly in the…annual report and the SEC 20F? A....[Y]eah, the prove [sic] reserves that he signs off gets published, yes.

Q. Okay. And...once he signs off, are changes made to those numbers? A. No." (Dep. pg. 119:10-24)

b) J. Bell

(1) "Q. In your position in EPB, did you have any responsibilities for filing reports with the SEC? A. I don't think I had a personal responsibility. My team helped to format the information that was submitted, and I think it was submitted by the finance or the legal organization. Q. Did you review that material? A. Reviewed the numbers in there, yes. Q. Do you recall what particular report that you reviewed? A. I reviewed the annual summation, the ARPR effectively that we talked about a few minutes ago and the key numbers that were in there. Q. With regard to SEC filings -- and SEC you understand to mean the Securities Exchange Commission, correct? A. Correct. Q. With regard to the SEC filings, I'm referring to the Form 20F that Shell had filed. Do you recall reviewing any other reserves information that was submitted to the SEC in connection with the 20F?...Q. And is that information different than the information that is assembled in connection with the ARPR? A. It shouldn't be. Q. So it should be identical? A. It should be." (Dep. pg. 67:5-68:15)

c) Roosch

(1) "Q. As a result of the ARPR process, do you recall if the numbers that were publicly reported by Shell with regard to proved reserves were lower than the numbers that you saw at the start of the process?...A. Yes, they were lower....Q. And generally can you tell us the reasons why the numbers were lower? A. We found a number of reserves changes that we had a feeling that could not be supported." (Dep. pg. 148:19-23, 149:5, 149:8-12)

(2) "Q. Once the process is concluded, what did you do with the information?...A. It was deposited on the files and in the records of the company, and it was translated into numbers for finance, for annual reporting. Q. Do you know if...the same numbers went directly from the reports that were generated at the end of the process into the annual reports? Was there also some interim steps? A. There were checks being made. Q. And who performed those checks? A. My co-workers were involved with that. Q. So is it fair to say then that that once the checks are preformed the results of the ARPR are reflected in the company's

public annual reports? A. Correct." (Dep. pg. 267:11-12, 267:17-25, 268:2-10)

d) *See* also J. Bell Decl. ¶ 5, Brass Decl. ¶¶ 13, 32.

TAB 5

FACT SUMMARY

V. SHELL'S REPORTING OF PROVED RESERVES

Shell communicated with shareholders, investors, analysts, and the general public from Europe, not from the United States. The United Kingdom and the Netherlands were the focal points for Shell's public-relations activities and dissemination of proved-reserves information during the Class Period.

Shell prepared and approved its proved-reserves disclosures in the United Kingdom and the Netherlands, and the information usually entered the allegedly efficient worldwide market for the first time in and from Europe. In other instances, Shell issued information about its proved reserves from its European offices to different geographic markets simultaneously. In no instance, however, did Shell's proved-reserves information first enter the worldwide market through U.S.-based conduct.

Shell had two types of public-relations functions: Investor Relations, which dealt with current and prospective investors in Shell securities, and External Affairs, which dealt with the media and other external communications. Both functions were directed from London.

A. Structure of Investor Relations Department

Shell's Investor Relations ("IR") function was directed from Shell Transport's headquarters in London. Simon Henry was the Head of Group Investor Relations from December 2000 until April 2004 and was based in London. Mr. Henry's predecessor, Wouter de Vries, also was based in London.

Shell divided its investor base into three distinct markets – the United Kingdom, Continental Europe, and North America – and viewed each market separately. Shell therefore maintained separate IR offices in London, The Hague, and New York, each of which was responsible for communicating with analysts and investors in its assigned regions of the world.

Each IR office had its own manager and its own staff, all of whom ultimately reported to the Head of Group Investor Relations, in London.

The London IR office was responsible for communicating with analysts and investors in the United Kingdom, Ireland, and Japan. The IR office in The Hague was responsible for communicating with analysts and investors in Continental Europe. The New York IR office was charged with communicating with analysts and investors in North America.

The Manager of Investor Relations, United Kingdom and Republic of Ireland, was Michael Harrop and then Gerard Paulides, both of whom were based in London. The Manager of Investor Relations, Continental Europe, was Jan van der Plas and then Bart van der Steenstraten, both of whom were based in The Hague. The Manager of Investor Relations, North America, was David Sexton and then Harold Hatchett, both of whom were based in New York. The Manager of Investor Relations in each office was the first point of contact with analysts and investors in his geographic area.

B. **<u>Structure of External Affairs Department</u>**

Shell's External Affairs department, which was separate from the IR department, was primarily based in London and The Hague, although it also had staff members located throughout the world. The External Affairs department was responsible for Shell's external communications with media (as well as its internal communications and Corporate Identity Program). Mary Jo Jacobi, who was based in London, was Vice President of Group External Affairs and directed this department from September 2001 to mid-2005.

Shell communicated with the media primarily from London and, to a lesser extent, The Hague. When dealing with non-U.K. media entities, including those based in the United States, Shell usually communicated through their London bureaus, not through their home offices. Thus, for example, Shell interacted with U.S. media companies such as *The Wall*

Street Journal, *The New York Times*, CNN, CNBC, and Bloomberg in London, through their London bureaus.[14] Shell made major news announcements through the London Stock Exchange's filing process; it sent other announcements by news wire from London.[15]

C. **<u>Types of Investor-Relations Communications</u>**

During the Class Period, Shell regularly provided information about its proved reserves (among other things) to the investment community as part of its overall IR program. Such information was disseminated in four principal types of communications: (*i*) annual Fourth Quarter and Full Year Results Announcements in February of each subsequent year ("4th Quarter QRAs"), (*ii*) an annual review of Shell's overall strategy that took place each year except 2002 ("Group Strategy Presentations"), (*iii*) a periodic update on Shell's Exploration and Production business (frequently in conjunction with presentations by other Shell businesses) ("EP Business Presentations"), and (*iv*) Shell's Annual Reports (which contained information that also was filed with the SEC on Forms 20-F). On certain occasions, proved-reserves information also might have been discussed in one-on-one meetings, field trips, and stand-alone presentations with analysts and investors.

Shell's communications about its proved reserves and related data were prepared and approved by Shell's London and The Hague IR offices. The New York IR office did not participate in that work. Rather, the New York IR office's role in preparing IR materials generally was limited to providing information on Shell's North American assets and operations

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14 Jacobi Dep. at 21:9-16, 22:3-8, 140:1-2; Henry Dep. at 55:13-16, 55:19-56:5.

15 Jacobi Dep. at 28:17-29:2.

and commenting on whether the materials prepared in Europe would resonate with North American investors.[16]

Moreover, Shell's IR program was structured so that significant presentations and communications with investors generally took place first in London or The Hague before being repeated later in the United States. As a result, information about Shell's proved reserves and related data usually entered the worldwide market for the first time in and from Europe, except in those cases when Shell's IR offices released the information from Europe simultaneously to different geographic markets. Shell never released proved-reserves information for the first time in or from the United States.

1. **Fourth Quarter and Full Year Results Announcements**

In early February of each year during the Class Period, Shell published its 4th Quarter QRA for the prior fiscal year ended December 31. The 4th Quarter QRA included, among other data, information on Shell's proved-reserves replacement ratio ("RRR"). Press conferences and analyst conferences followed these disclosures. The 4th Quarter QRAs always were prepared in and released from Europe; the press conferences were held only in Europe, and the analyst presentations were held first (and usually only) in Europe.

a. **4th Quarter QRAs**

Each 4th Quarter QRA was prepared by Shell's IR personnel in London and The Hague. The data on which the 4th Quarter QRA was based were aggregated and prepared for publication by the Group reporting function based in London. The European IR offices occasionally consulted with the New York IR office about specific questions concerning U.S.-

16 Sexton Decl. ¶ 14.

related issues, but the New York IR office was not otherwise involved in aggregating the data or preparing the report.[17]

When the 4th Quarter QRA was ready for publication, Shell's IR offices in London or The Hague issued it simultaneously to the relevant stock exchanges in all countries where shares of Royal Dutch and Shell Transport were listed for trading, as well as to the worldwide wire services. Shell's IR offices in London or The Hague then posted the 4th Quarter QRA on Shell's website and released it to the general media.[18]

Once this process was complete and the 4th Quarter QRA had become public, Shell sent it to financial analysts. Before 2002, each of the three IR offices sent the 4th Quarter QRA by e-mail or fax to the analyst contacts in that office's geographic region. (The New York office therefore sent the 4th Quarter QRA only to North American contacts.) After 2002, the London or The Hague IR office assumed responsibility for sending the 4th Quarter QRA to all analysts, including those in the United States.[19]

Shell also furnished each 4th Quarter QRA to the SEC on Form 6-K. These filings were made from the London and The Hague IR offices.[20]

b. **Press Conferences**

In conjunction with issuing the 4th Quarter QRA, Shell held press conferences to address media questions. Each year during the Class Period, an initial press conference was held

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17 Sexton Decl. ¶ 13(a).

18 Henry Decl. ¶¶ 19-20.

19 Sexton Decl. ¶ 13(a).

20 Henry Decl. ¶ 21.

in The Hague, and another was held in London either simultaneously with or shortly after the one in The Hague. Such press conferences were never held in the United States.[21]

c. **Analyst Presentations**

The annual press conferences accompanying the 4th Quarter QRA were typically followed later the same day by an analyst presentation. The analyst presentations always were held first (and usually only) in Europe.[22]

- The February 1999 analyst presentation was held in The Hague, with live satellite connection to London and New York.
- The February 2000 analyst presentation was held in The Hague and was simultaneously available for the first time via webcast.
- The February 2001 analyst presentation also was held in London and was available via webcast.
- The February 2002 analyst presentation again was held in London and was available via webcast.
- The February 2003 analyst presentation was held in London and was available via webcast. Because this analyst presentation was combined for the first time with a Group Strategy Presentation (described below), a similar analyst presentation was held the next day in New York.
- The February 2004 analyst presentation was held simultaneously in The Hague and London, in combination with the annual press conference (as described above). These combined presentations were followed a day later by an analyst presentation in New York.

2. **Group Strategy Presentations**

During the Class Period, Shell made regular presentations to the media and analysts concerning its overall corporate strategy. Although these sessions would touch on issues related to Shell's Exploration and Production business (including new projects that might

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21 van der Steenstraten Decl. ¶ 5(c).

22 van der Steenstraten Decl. ¶ 5(c).

result in new reserves additions), neither Shell's proved reserves nor its expected RRR were a significant part of these meetings. The Group Strategy Presentations always were held first in Europe.[23]

- Until 2002, Group Strategy Presentations were held in December in London and were followed a day later by similar presentations in New York.
- No Group Strategy Presentation was held in December 2002, but the next strategy presentation was combined with Shell's 4th Quarter QRA presentation in February 2003. That presentation was held in London, followed by a similar analyst presentation the next day in New York.
- The 2004 Group Strategy Presentation did not occur until September (after the end of the Class Period) because of Shell's announcements earlier in the year regarding its recategorization of proved reserves.

3. **<u>EP Business Presentations</u>**

Shell's Exploration and Production business occasionally made additional presentations during the year, to address specific aspects of its business. For example, EP held EP Business Presentations in April 1999, April 2000, September 2001, and March 2003. With one exception (in 1999), all of these presentations took place first in Europe before being repeated in the United States.[24]

The presentation in April 1999 took place first in New York and was followed a day later by a similar presentation at Shell's global EP headquarters in Rijswijk, the Netherlands. The April 1999 presentation was the only one during the Class Period that was conducted first in the United States before being repeated in Europe. But Shell already had disclosed all of the key proved-reserves information and related data mentioned in this presentation before the New York session took place. The prior disclosure had occurred either (*i*) through a press release that was

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23 van der Steenstraten Decl. ¶ 6.

24 van der Steenstraten Decl. ¶ 7(a).

simultaneously issued from Shell's IR offices in London and The Hague to stock exchanges and wire services around the world or *(ii)* in IR announcements and presentations in Europe.

The EP Business Presentation in April 2000, which was combined with a presentation by Shell's Gas and Power business, took place first in The Hague, followed a day later by a similar presentation in Houston. The EP presentation in September 2001 took place first in London and was followed a day later by a similar presentation in New York. The EP presentation in March 2003, which again was combined with a presentation by Gas and Power, took place first in London was followed a day later by a similar presentation in New York.

The background briefing materials that Shell officials used for the Group Strategy Presentations and EP Business Presentations were initially prepared by the business units themselves and were then finalized and approved by IR personnel in London and The Hague. IR personnel in London and The Hague also prepared and approved the direct remarks and presentation materials for these presentations.[25]

The New York IR office was responsible for preparing materials only for the portion of presentations addressing Shell's Chemicals business. The New York office was not involved in the portions of presentations addressing the EP business, which reports Shell's proved reserves. Those portions were prepared by IR personnel in either London or The Hague.[26]

4. **Annual Reports**

Each year during the Class Period, Royal Dutch and Shell Transport released their respective Annual Reports in March or April. Two versions of the Annual Report were

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[25] Sexton Decl. ¶¶ 13(b)-(c).

[26] Sexton Dep. at 67:3-6, 67:15-23.

published: a long-form version and a short-form summary. Both versions of the Royal Dutch Annual Report were published in both Dutch and English. Both versions of the Shell Transport Annual Report were published in English only.[27]

Each long-form Annual Report included, as unaudited supplemental information to the Group's financial statements, information on Shell's proved oil and gas reserves and on RRR for the year. The long-form reports were prepared in the Netherlands and the United Kingdom, printed in the United Kingdom, and posted on Shell's website from London or The Hague.[28]

Similarly, each short-form summary of the Annual Report was prepared in the Netherlands and the United Kingdom, printed in the United Kingdom, and, beginning with the 2000 Annual Report, posted on Shell's website from London or The Hague. The short-form summaries did not contain the same unaudited supplemental information on proved reserves that appeared in the long-form versions, but they did contain a short summary of year-end proved reserves. Starting with the short-form 2003 Annual Report, the short-form version also stated the RRR for the year.[29]

After the Annual Reports had been posted on Shell's website from Europe, Shell's IR offices in London or The Hague sent either a long-form or a short-form version of the report to (*i*) registered shareholders, (*ii*) shareholders who had requested a copy of the report, or (*iii*) beneficial owners in the United States (except for those beneficial owners who had indicated

27 Henry Decl. ¶¶ 22-23.

28 Henry Decl. ¶ 24; van der Steenstraten Decl. ¶ 8(a).

29 Henry Decl. ¶ 25; van der Steenstraten Decl. ¶ 8(a).

they did not wish to receive such reports). Shell normally sent the short-form version to these shareholders, unless they specifically requested the long-form version.[30]

Royal Dutch and Shell Transport officially reported the Group's proved reserves to the SEC in an Annual Report filed on SEC Form 20-F. Each year, both companies filed the same Form 20-F. The reports were filed from the IR offices in London and The Hague. The proved-reserves figures in those filings were the same as those in the previously distributed long-form Annual Reports.[31]

For most years during the Class Period, the Annual Reports were published in The Hague and London several days before the Forms 20-F were filed with the SEC. The only exception was for the year 2001, when the Annual Reports were published and the Forms 20-F were filed on the same date.[32]

5. **One-on-One Meetings, Field Trips, and Stand-Alone Presentations**

Shell also engaged in three other types of investor and analyst communications that occasionally could have included information about Shell's proved reserves: one-on-one meetings, field trips, and stand-alone presentations.

a. **One-on-One Meetings**

Each year during the Class Period, Shell executives participated in one-on-one meetings, or "road shows," with large shareholders and analysts in the United Kingdom, Continental Europe, and the United States. These one-on-one meetings generally took place after the 4th Quarter QRA presentations and Group Strategy Presentations, although they also

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30 Henry Decl. ¶ 26.

31 Henry Decl. ¶ 27.

32 Henry Decl. ¶ 27.

occasionally took place at other times throughout the year. Questions about proved reserves or RRR could have arisen during these meetings, but Shell did not disclose any market-sensitive or proved-reserves information that it had not previously released to the public.[33]

The one-on-one meetings were designed for investors and analysts who lived or worked where the meetings were held. Thus, Shell held separate meetings outside the United States for non-U.S. investors and analysts, and inside the United States for U.S.-based investors and analysts. No one-on-one meetings were held in the United States with European-based investors or analysts.[34]

b. **<u>Field Trips</u>**

During the Class Period, Shell also conducted two "field trips" that brought both buy-side and sell-side analysts to some of Shell's operating locations around the world. In September 1999, a field trip went to Egypt, Germany, and the Netherlands; it did not visit the United States. In October 2002, a field trip went to Shell's oil-sands project in Canada and to Shell's offices in Houston.

The 2002 trip focused on the Canadian project, which was an important strategic venture for Shell and was unfamiliar to European analysts. Shell was eager for the European analysts to understand the project, because it was a major investment that would produce oil, even though the oil would not count as proved reserves under SEC regulations. Having decided to bring the European analysts over to North America, Shell then added a first stop in Houston,

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33 Henry Decl. ¶¶ 37-40.

34 Henry Decl. ¶¶ 38, 40.

to allow the "downstream" businesses (which do not have, estimate, or report proved reserves) to discuss their operations with the analysts.[35]

On the first day of the Houston portion of the field trip, the analysts and investors attended presentations about Shell's downstream operations in the United States (including Shell's Oil Products and Chemicals businesses) and visited a refinery. On the second day, they attended morning presentations on Shell's EP business in the United States and on the use of technology within the EP business generally. The analysts and investors then flew to Canada that afternoon.[36]

According to the head of Shell's IR department (Mr. Henry), it is possible that the subject of Shell's RRR came up during conversations with analysts, but it is unlikely that Shell representatives and the analysts discussed Shell's as-reported proved reserves.[37] In any event, Shell did not disclose during this field trip any market-sensitive or proved-reserves information that it had not previously released to the market from Europe.

c. **Stand-Alone Presentations**

Shell occasionally conducted stand-alone presentations, such as those at investment-bank energy conferences. Shell held separate presentations outside the United States for non-U.S. audiences and inside the United States for U.S. audiences.[38]

The content of these presentations was almost always derived from Shell's prior disclosures. While a presentation might sometimes touch on a new topic that had not been

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35 Henry Dep. at 214:5-8, 214:10-12, 214:20-21, 215:6-9.

36 Henry Decl. ¶ 45.

37 Henry Dep. at 220:5-11, 222:9-16, 228:18-20.

38 Henry Decl. ¶ 43.

addressed in a previous presentation, such as developments in Shell's technology, these presentations never disclosed market-sensitive information or proved-reserves information that had not previously been issued to the market from Europe.[39]

D. **Review of Reserves-Related Statements**

To determine when and where information about Shell's proved reserves first entered the worldwide market, Shell reviewed all the IR-related materials included in the evidentiary record presented to the Special Master. This record includes deposition exhibits and documents that plaintiffs and Shell designated pursuant to the Special Master's Order. The IR-related documents include IR presentations, briefing materials, and regulatory filings, for IR events both inside and outside the United States. Shell analyzed plaintiffs' designated documents reflecting reserves-related statements and matched their contents to similar or identical information that was previously or simultaneously issued outside the United States.[40]

The chart in Section V of Shell's factual submission demonstrates that, whenever information related to Shell's proved reserves was (or might have been) disseminated in the United States, the dissemination occurred simultaneously with or *after* the dissemination of similar, if not identical, information from outside the United States. In no case was reserves-related information ever disclosed first in the United States. Not surprisingly, Shell – an Anglo/Dutch company based in and run from Europe – communicated with its mostly European shareholder base, with worldwide markets, and with the SEC from Europe.

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39 Henry Decl. ¶ 42.

40 For the purpose of this review, "reserves-related" was defined to mean a statement about proved reserves, RRR, or Return on Average Capital Employed.

FACT SUPPORT

V. SHELL'S REPORTING OF PROVED RESERVES

A. Structure of Investor Relations Department

1. Shell's IR function was based in Europe.

a) During the Class Period, Shell was an Anglo-Dutch company headquartered in London and The Hague. During this time, the IR function was directed out of London.

(1) Henry

(a) " The Group was formed in 1907 when Royal Dutch Petroleum Company ..., based in the Netherlands, merged its operations with The "Shell" Transport and Trading Company, p.l.c. ..., based in the United Kingdom. Both Royal Dutch and Shell Transport, however, maintained their distinct corporate identities." (Decl. ¶ 5)

(b) "The IR function, including the drafting of IR-related materials and information related to the Group's proved reserves, was directed out of Group headquarters in London, England, where I maintained my offices throughout my tenure as Head of Group IR." (Decl. ¶ 15)

(2) Sexton

(a) "For the entire period in which I was Manager of Investor Relations, North America, Shell's Investor Relations function was directed out of Shell's headquarters in London, England." (Decl. ¶ 4)

2. Shell maintained separate IR offices in London, The Hague, and New York.

a) Shell maintained separate IR offices in London, The Hague, and New York, each of which was responsible for communicating with analysts and investors in different regions of the world. Each IR office had its own manager and its own staff, all of whom ultimately reported to the Head of Group Investor Relations, in London.

(1) Henry

(a) "We had a small team of ten people, and we ran three offices, and I had three senior individuals report to me . . . Michael Harrop, who was based in London . . . was responsible for the U.K. and Republic of Ireland, all investors in those countries ... Bart van der Steenstraten was based in The Hague in the Netherlands, and he was responsible for all investors based in Continental Europe, and ... David Sexton who was based in New York, and he was responsible for communication with investors based in North America, both the U.S. and Canada." (Dep.[1] pg. 23:24-24:17)

(2) Sexton

(a) "Shell maintained separate investor-relations offices in London, The Hague, and New York to communicate with analysts and investors in different parts of the world. Each office had its own manager and its own staff, all of whom ultimately reported to the Head of Group Investor Relations, in London." (Decl. ¶ 4)

b) Simon Henry was Head of Group Investor Relations from December 2000 until April 2004 and was based in London. Mr. Henry's predecessor was Wouter de Vries, who was also based in London.

c) The Manager of Investor Relations, United Kingdom and Republic of Ireland, was Michael Harrop and then Gerard Paulides, both of whom were based in London.

(1) The London IR office was the largest of the three IR offices.

(a) Henry

(i) "In London, we already had some staff, some support staff. The staff was increased during my time in the position. The establishment was a senior analyst position, a junior analyst type position, plus an individual responsible for logistics and road

[1] Testimony references are to Securities Class Action testimony unless otherwise indicated.

shows and events, helping with websites, et cetera." (SEC Testimony pg. 19:18-23)

d) The Manager of Investor Relations, Continental Europe, was Jan van der Plas and then Bart van der Steenstraten, both of whom were based in The Hague.

(1) The Hague IR office was smaller than the London IR office.

(a) Henry

(i) "In the Netherlands . . . in late 2001, we recruited an analyst, and in late 2003, we replaced that analyst when he moved onto a new job, in the middle of 2003 actually, he moved onto a new position." (SEC Testimony pg. 19:14-17)

e) David Sexton was Manager of Investor Relations, North America, from July 1999 to September 2003 and was based in New York. Mr. Sexton's replacement was Harold Hatchett, who was also based in New York.

(1) The New York IR office was also smaller than the London office.

(a) Henry

(i) "In the U.S., we recruited an analyst to support David Sexton in late 2002. Before that, David did it on his own." (SEC Testimony pg. 19:11-13)

(b) Sexton

(i) "During my entire tenure (July 1999 to July 2003) as Manager of Investor Relations, North America, I was based in New York. The Investor Relations office in New York was small. From 1999 to 2002, the office consisted solely of my personal assistant and me. Later in 2002, we hired an additional employee, who was responsible for retail investors in North America and who reported to me." (Decl. ¶ 7)

f) The London IR was responsible for communicating with analysts and investors in the United Kingdom, Ireland, and Japan. The IR office in The Hague was responsible for communicating with analysts and investors in Continental Europe. And the New York IR office was responsible for communicating with analysts and investors in North America.

(1) Henry

(a) "In addition, the London IR office acted as a liaison between the Group and the community of analysts and investors in the United Kingdom, Ireland, and Japan. Other than the IR office in London, there were two Group IR offices charged with acting as liaisons between the Group and analysts and investors in other parts of the world. Each of those offices was responsible for a different geographical area. The IR office in The Hague liaised with analysts and investors in Continental Europe. The IR office in New York liaised with analysts and investors in North America." (Decl. ¶¶ 15-16)

(2) Sexton

(a) "The London office was responsible for communicating with analysts and investors in the United Kingdom, Ireland, and Japan. The office in The Hague was responsible for communicating with analysts and investors in Continental Europe. And the New York office was responsible for communicating with analysts and investors in North America." (Decl. ¶ 5)

g) The Manager of Investor Relations in each office was the first point of contact with analysts and investors in their geographic area.

(1) Henry

(a) "[A]ny U.S.-based investor would contact the New York office, and a European-based investor would contact The Hague, so first point of contact." (Dep. pg. 25:23-26:2)

(b) "The Group directed analysts and investors to contact the IR office for their region with any questions or communications. An investor in France, for example, was directed to the IR office in The Hague. An investor in the United States was directed to the IR office in New York. Only on very rare and exceptional occasions would an IR office be called upon to answer a question posed by an investor or analyst from outside that office's designated geographical area." (Decl. ¶ 17)

3. The New York IR office.

a) Mr. Sexton, the Manager of Investor Relations, North America, was responsible for providing information about Shell to United States shareholders and for encouraging new United States investors to become Shell shareholders. Mr. Sexton was also responsible for organizing the logistics for IR presentations in the United States and for monitoring the financial press in the United States.

(1) Sexton

(a) "As Manager of Investor Relations, North America, I had two main responsibilities: to provide information about Shell to United States shareholders and to encourage new United States investors to become Shell shareholders. In addition, I was responsible for organizing and arranging the logistics for Investor Relations presentations in the United States and monitoring the financial press in the United States." (Decl. ¶ 8)

b) The New York IR office was the primary point of contact for investors and analysts based in North America and focused on communicating with the North American market. The New York IR office rarely communicated with investors or analysts based outside North America.

(1) Sexton

(a) "I was the primary point of contact for investors and analysts based in North America. The New York Investor Relations office focused on communicating with the North American market. We rarely communicated with investors or analysts based outside North America." (Decl. ¶ 9)

(b) "Q: Did you ever have contact with market professionals from either brokerage houses or financial media outlets that were headquartered outside of the United States? A: As a general practice, my interaction with analysts of the nature you describe were analysts that were physically based here in the United States. However, due to the nature of that particular business, on occasion you would come into contact with people that were based outside the United States." (Dep. pg. 16:17-17:3)

(c) "Q: [D]o you recall having any such contacts with foreign analysts during your tenure at IR? A: It is the general practice of our office to allow each of the Investor Relations people to be the focal point for contacts with investors and market professionals in their geographic area. On a rare occasion, whenever, for example, it was late in the afternoon in the U.S. and someone in London was working very late, you may get a call that was about a very specific topic that would come to the U.S. simply because they wanted an answer in that physical day, and you might answer that; or someone would call from outside the United States to ask me about a specific issue in the United States which I responsible for. Q: With regard to the former scenario where you would be contacted because of time constraints and the lateness of the hour, do you recall how many times that happened during your tenure? A: I just said that was the exception rather than the rule, and again I used the word "rare." It was a very rare occasion, because there's not that much that is that critical that the Investor Relations person is going to share so it wasn't an event that occurred very often." (Dep. pg. 45:15-46:16)

c) Mr. Sexton recalled two occasions on which he was contacted by a non-U.S. investor or analyst with questions about Shell's North American assets and operations– neither of which had anything to do with reserves issues.

(1) Sexton

(a) "Q: Do you recall any of the specific activities about which you were contacted by those non-U.S. based investors or analysts? A: I'll give you two. In my tenure there we acquired Texaco's downstream interests. We had a joint venture with Texaco, and because I was in the U.S. and was somewhat involved in the periphery of that particular acquisition, there were a lot of questions about that. About a year later our company made a decision to buy Pennzoil Quaker State Lubricants Company, and a result of that also being predominantly a U.S. transaction, there were questions about that as well." (Dep. pg. 48:11-23)

(b) "Occasionally, I was contacted by an investor or analyst from outside North America simply because of time-zone differences – at certain times, the London and The Hague Investor Relations offices were closed, but the New York office was still open. On a few other occasions, I was contacted by investors or analysts from outside North America with specific questions about Shell's assets or operations in the United States, such as questions regarding Shell's acquisition of Texaco's downstream interests and Shell's acquisition of the Pennzoil Quaker State Lubricants Company. Such contacts with non-North American investors and analysts, however, were very rare." (Decl. ¶ 10)

B. Structure of External Affairs Department

1. Shell's External Affairs function was also based in London and The Hague.

a) Shell's External Affairs department, which was separate from the IR department, was primarily based in London and The Hague, although it also had staff members located throughout the world (including the United States). The External Affairs department was responsible for Shell's external communications with the media (as well as its internal communications and Corporate Identity Program).

(1) Mary Jo Jacobi, Vice President of Group External Affairs from September 2001 to mid-2005, was based in London. Her reports were based in London and The Hague.

(a) Jacobi

(i) ". . . my direct reports and second-tier reports were in London and The Hague." (Dep. pg. 14:11-12)

(2) Shell's media relations team, which was a part of the External Affairs department, was based in London.

(a) Jacobi

(i) "The team in London, the media relations team, specifically had responsibility for the global media in general and that would have included what you refer to as the 'financial media.'. . . James Herbert was the head of media relations for a time; Stuart Bruseth succeeded him." (Dep. pg. 19:9-12, 19: 18-19)

(3) Announcements to the media about Shell were primarily handled out of London and, to a lesser extent, The Hague.

(a) Jacobi

(i) "The primary focus and primary locus for the group, the parent companies and the entity as a whole, in dealing with the news media was London. And many news organizations regardless of whether they are based in Paris or Frankfurt or Tokyo have London Bureau. The primary work on behalf of the Royal Dutch Shell Group of companies was done out of London." (Dep. pg. 20:18-24)

(ii) "A: Major news announcements were sent through the filing process of the London Stock Exchange. More routine announcements were disseminated electronically. Q: Okay. Could you describe how they were disseminated electronically? A: Generally by fax. Q: Are you aware if press releases were electronically published over the internet through either press wire or business wire? A: As I recall PR news wire in London was the principle means of electronic dissemination." (Dep. pg. 28:17-29:2)

(iii) "Announcements on behalf of the parent companies, and therefore Royal Dutch Shell Group, were handled directly and almost exclusively by the team in London and to a lesser degree the team in The Hague. . . .

They would include the quarterly result announcements" (Dep. pg. 158:23-159:5-6)

(4) When dealing with non-U.K. media entities, including those based in the United States, Shell usually communicated through their London bureaus, not through their home offices. Thus, for example, Shell interacted with U.S. media companies such as *The Wall Street Journal*, *The New York Times*, CNN, CNBC, and Bloomberg in London, through their London bureaus.

(a) Jacobi

(i) "Q: Did members of the team interact with members of the Wall Street Journal? A: Principally through the London Bureau of the Wall Street Journal, yes they. [sic] Q: Do you recall if members of that team had any interaction with representatives of the New York Times? A: Through the New York Times London Bureau, I believe they did." (Dep. pg. 21:9-16)

(ii) "The primary contacts with the broadcast media were handled through London. Organizations such as the BBC, ITV, Sky Television, CNBC through its London Bureau, CNN through its London Bureau, Star in Asia, and various other broadcast news organizations based in other parts of the world through their London Bureau." (Dep. pg. 22:3-8)

(iii) "Bloomberg's [sic] in the U.K. has a very large presence here and did cover Shell out of its London Bureau." (Dep. pg. 140:1-2)

(b) Henry

(i) "Q: Do you recall specifically which members of the United States financial media were invited to those press conferences? . . . A: To the best of my knowledge, it would be the London-based Bureau of Representatives of the 'Wall Street Journal,' the 'New York Times.' And just to be clear, the same was true about the wire services. It was the London representatives. All reports that came out following any of the discussions, quarterly results or otherwise, would come from the London office; for example, Bloomberg. We never, in my experience, spoke to U.S.-based journalists or financial media." (Dep. pg. 55:13-16, 55:19-56:5)

(5) The U.S. External Affairs team communicated with local media in the United States.

(a) Jacobi

(i) "Their duties and responsibilities were similar to the various External Affairs teams around the world and included internal communications on behalf of Shell in the U.S.; dealing with local media in the United States, principally in Houston, dealing with community groups and non-governmental organizations and stakeholder organizations." (Dep. pg. 16:11-17)

C. Types of Investor-Relations Communications

1. During the Class Period, Shell regularly provided information on its proved oil and gas reserves (among other things) to the investment community as part of its wider overall IR program. Such information was provided in four principal types of communications: (*i*) the Fourth Quarter and Full Year Results Announcements in February of each subsequent year ("4th Quarter QRA"); (*ii*) an annual review of Shell's overall strategy that took place each year except 2002 ("Group Strategy Presentations"); (*iii*) a periodic update on Shell's Exploration and Production business (frequently in conjunction with presentations by other Shell business) ("EP Business Presentations"); and Shell's Annual Reports (which contained information that also was filed with the SEC on Forms 20-F).

a) *See* van der Steenstraten Decl. ¶ 4.

2. On certain occasions, proved reserves information also might have been discussed in one-on-one meetings, field trips, and stand-alone presentations with analysts and investors.

3. As detailed below, Shell's communications about its proved reserves and related data were prepared and approved by Shell's London and The Hague IR offices; the New York IR office was not responsible for

preparing or approving these communications. Instead, the New York IR offices' role in preparing IR materials generally was limited to providing information on Shell's North American assets and operations and commenting on whether the materials prepared in Europe would resonate with investors in North America.

a) Sexton

(1) Q: [C]an you generally describe your role specifically, if any, in connection with the preparation of those [briefing] materials. A: I would say I had two roles. One, like any member of the group, I was asked to answer questions like: Does this hang together; does this – will this resonate with the investors in your part of the world; is there something that we're missing; those kinds of general questions. And then also because I was physically located in the United States, I was asked to specifically look at comments, references, words that related to U.S. assets, U.S. events, to make sure they were accurate." (Dep. pg. 42:17-43:7)

(2) "Q: Did you, however, specifically participate in the actual drafting of the prepared remarks? A: I seldom do the actual drafting. My role, as I stated earlier, was mainly review, uh, offer comment, and specifically around U.S.-based assets was my responsibility." (Dep. pg. 73:11-17)

(3) "Thus, neither I nor anyone else in the New York Investor Relations office was responsible for preparing or approving the primary communications between Shell and its investors concerning proved reserves. My role in preparing Investor Relations materials generally was limited to providing information on Shell's North American assets and operations and commenting on whether the materials prepared in Europe would resonate with investors in North America." (Decl. ¶ 14)

4. Moreover, Shell's IR program was structured so that significant presentations and communications with investors generally took place first in London or The Hague before being repeated later in the United States. As a result, information about Shell's proved reserves and related data usually entered the worldwide market for the first time in and from Europe, except in those cases when Shell's European IR offices released the information simultaneously to different geographic markets.

5. Thus, information related to Shell's proved reserves was never disseminated into the market for the first time in or from the United States.

(1) Sexton

(a) "Q: During your tenure with IR in the United States, were there occasions when information was disseminated into the financial market first in the United States and then in Europe? A: As a general rule, it always started in Europe. I don't recall a specific time where information was first disseminated in the U.S. I just don't recall that." (Dep. pg. 108:15-23)

6. Fourth Quarter and Full Year Results Announcements

a) In early February of each year during the Class Period, Shell published its 4th Quarter QRA for the prior fiscal year ended December 31. The 4th Quarter QRA included, among many other pieces of data, information on Shell's proved reserves replacement ratio ("RRR").

(1) *See* van der Steenstraten Decl. ¶ 5.

b) Each 4th Quarter QRA was prepared by Shell's IR personnel in London and The Hague. The data on which the 4th Quarter QRA was based were aggregated and prepared by the Group reporting function based in London. The European IR offices occasionally consulted with the New York IR office about specific questions concerning U.S.-related issues, but the New York IR office was not otherwise involved in aggregating the data or preparing the report.

(1) Henry

(a) "London was where we did all the regulatory reporting, such as the quarterly results, and any contribution to the annual filings were coordinated out of London." (Dep. pg. 24:25-25:4)

(b) "I mentioned the QRAs in two sections. There is a narrative and there is a set of data. The data was prepared by the Group Reporting function, a small team based in London. All financial statements would come through there with auditors normal financial reporting process. Based on those data, Mike [Harrop] and then Gerard [Paulides] would prepare a first draft of what they believed should be in the QRA for that period." (Dep. pg. 42:17-25)

(c) "The IR function, including the drafting of IR-related materials and information related to the

Group's proved reserves, was directed out of Group headquarters in London, England, where I maintained my offices throughout my tenure as Head of Group IR. All of the work that was done by IR in assisting the Group in the preparation of its quarterly and annual results and other regulatory reporting was directed from IR's London office." (Decl. ¶ 15)

(2) Sexton

(a) "Each 4th Quarter QRA was prepared by Shell's Investor Relations personnel in London and The Hague. The data on which the 4th Quarter QRA was based were aggregated and prepared by the Group reporting function based in London. During my tenure as Manager of Investor Relations, North America, my colleagues in London and The Hague who prepared the 4th Quarter QRA occasionally consulted me with specific questions about United States issues. The New York Investor Relations office, however, was never involved in approving the 4th Quarter QRA or issuing the 4th Quarter QRA to any regulatory agencies." (Decl. ¶ 13a)

c) When ready for publication, the 4th Quarter QRA was simultaneously issued in all the countries where the shares of Royal Dutch and Shell Transport were listed. The issuance was accomplished by simultaneous delivery from the London or The Hague IR offices to relevant stock exchanges and worldwide wire services.

(1) van der Steenstraten

(a) "When ready for publication, the 4th Quarter QRA was simultaneously issued in all the countries where the shares of Royal Dutch and Shell Transport were listed.... The issuance of each Annual Earnings Release was accomplished by simultaneous delivery to the relevant stock exchanges and worldwide wire services." (Decl. ¶ 5)

(2) Henry

(a) "When ready for publication, the announcement of the Group's quarterly or annual financial results ... was simultaneously issued in all the countries where the shares of Royal Dutch and Shell Transport were listed. The issuance was accomplished by simultaneous delivery from the London or The Hague Investor Relations offices to relevant stock exchanges and worldwide wire services." (Decl. ¶ 19)

d) The 4th Quarter QRA was then posted on Shell's website and released to the general media. The posting was done from Shell's IR offices in London or The Hague.

(1) *See* Henry Decl. ¶ 20.

e) The New York IR office was never involved in the dissemination of the 4th Quarter QRA, including the release or issuance to any regulatory agencies.

(1) *See* Sexton Decl. ¶13(a).

f) Once the 4th Quarter QRA had become public information, it was sent to financial analysts. Before 2002, each of the three IR offices sent the 4th Quarter QRA via email or fax to the analyst contacts in that office's geographic region. The New York office therefore sent the 4th Quarter QRA only to North American contacts. However, the New York IR office never sent the 4th Quarter QRA to North American analysts before the regulatory disclosures were made from the European IR offices and the information was already publicly available in the market. After 2002, the London or The Hague IR office assumed responsibility for sending the 4th Quarter QRA to all analysts, including those in the United States.

(1) Sexton

(a) "Q: How were those press releases publicly disseminated? A: They were issued out of our London office. Q: Do you recall the medium with which they were publicly disseminated? And by that I mean do you recall, for example, if they were published on Business Wire or some other news service? A: Quarterly news releases come out in three fashions: One, there is a mandatory Stock Exchange release; two, there is a release that goes off over PR newswire; and then third, the press release was e-mailed to certain analysts. Q: With respect to the dissemination of the press release over PR newswire, was that a worldwide dissemination – A: Yes, it was. Q: Do you recall approximately how many analysts were e-mailed the press release upon the issuance? A: I can only speak for the U.S., and that number was probably approaching a hundred. Q: Do you know if such press releases were also e-mailed to analysts in the UK and/or Continental Europe? A: The same practice that I employed was done by my colleagues in other parts of the world." (Dep. pg. 58:6-59:8)

(b) "Once the 4th Quarter QRA had become public information, it was sent to financial analysts. Before 2002, I was responsible for sending the 4th Quarter QRA via fax or email to analyst contacts in North America, and my colleagues in the London and The Hague Investor Relations offices were responsible for sending the 4th Quarter QRA to analysts in their geographic regions. After 2002, however, the London Investor Relations office assumed responsibility for sending the 4th Quarter QRA to all analysts, including those in the United States." (Decl. ¶ 13(a)).

g) Shell also filed each 4th Quarter QRA with the SEC on Form 6-K. These were filed from the London and The Hague IR offices.

(1) *See* Henry Decl. ¶ 21.

h) In conjunction with the issuance of the 4th Quarter QRA, Shell also held press conferences to address media questions. Each year during the Class Period, an initial press conference was held in The Hague, and another was held in London. The London press conference was held either simultaneously with or shortly after the press conference in The Hague. Such press conferences were never held in the United States.

(1) Sexton

(a) "Q: Am I correct that those press conferences were typically conducted out of either London or The Hague? A: That is correct. . . . Q: Do you know if those press conferences were broadcast within the United States? A: If you're specifically talking about the press conferences, I would say as a general rule, no." (Dep. pg. 63:11-14, 63:18-22)

(2) Jacobi

(a) "The teleconference with the wire services would be conducted after the quarterly results announcement was issued to the public via the London Stock Exchange and news wire and the purpose was to answer any immediate questions that the wire services might have in anticipation that they would be relied upon by other organizations, news and otherwise, in the first instance for the results." (Dep. pg. 42:14-20)

(b) "We did no press conference in connection with those trips to New York because the news had been made the previous day in London and there was no, pardon me, new news." (Dep. pg. 63:21-24)

(c) "Q. Are you aware if there were press conferences in connection with the year end results announcements that were conducted anywhere other than London? A. To the best of my recollection: no; although later in my tenure there were press conferences conducted in The Hague. Q. Those times when the press conferences were conducted in The Hague, were there also press conferences conducted in London? A. Yes there were." (Dep. pg: 68:20-69:4)

i) These press conferences were typically followed later the same day by an analyst presentation. In February 1999, the analyst presentation was held in The Hague, with live satellite connection to London and New York. In February 2000, the analyst presentation was held in The Hague and was simultaneously available for the first time via webcast. In February 2001 and February 2002, the analyst presentations were held in London and were available via webcast. In February 2003, the analyst presentation was held in London and was available via webcast. Because this 4th Quarter QRA analyst presentation was combined for the first time with the Group Strategy Presentation (described below), a similar analyst presentation was held the next day in New York. In February 2004, the simultaneous press conferences held in The Hague and London were combined with simultaneous analyst presentations in each of those cities. The combined press conferences and analyst presentations held in The Hague and London were followed a day later by an analyst presentation in New York.

(a) *See* Henry Decl. ¶¶ 28.

(b) *See* van der Steenstraten Decl. ¶ 5(c).

(c) Jacobi

(i) ". . . . with respect to the conference in New York, the format was the same as the presentation in London. The content was the same as the presentation in London." (Dep. pg. 66:19-21)

7. Group Strategy Presentations

a) During the Class Period, Shell made regular presentations to the media and analysts concerning its overall corporate strategy. Although these sessions would touch on issues related to Shell's Exploration and Production business (including new projects that might result in new reserves additions), neither Shell's proved reserves nor expected RRR were a significant part of these meetings.

(1) *See* van der Steenstraten Decl. ¶ 6.

b) During the Class Period, Group Strategy Presentations were always held first in Europe before being repeated the following day in the United States. Until 2002, Group Strategy Presentations were held in December in London and were followed a day later by similar presentations in New York. No Group Strategy Presentation was held in December 2002, but the next strategy presentation was combined with Shell's 4th Quarter QRA presentation in February 2003. As discussed above, the February 2003 presentation was held in London, followed by a similar analyst presentation the next day in New York. In 2004, Shell's Group Strategy Presentation did not occur until September, because of Shell's announcements earlier in the year regarding its recategorization of proved reserves.

(1) *See* van der Steenstraten Decl. ¶ 6.

(2) Henry

(a) "Q: Where were these Strategy Presentations conducted? A: We used to do two versions. The first one was always held in London, and usually we followed up a day later in New York. ... Q: Why did the group conduct two Strategy Presentations? A: Just to be clear, the content was the same. We didn't have two strategies. The content was always the same, and they were only 24 hours apart. ..." (Dep. pg. 104:18-22, 105:3-8)

(b) "Q: I believe you indicated that the Group Strategy Presentations were conducted in New York the following day, typically; is that correct? A: The Group Strategy Presentation, yes, and some, if not all, of the Business Strategy Presentations were also followed up in New York. Q: Were the prepared statements that were delivered at the New York presentations the same as those given in the London presentations? A: Usually exactly the same." (Dep. pg. 141:17-142:3)

(c) *See* also Henry Decl. ¶¶ 32-35.

(3) Jacobi

(a) "... the strategy presentation in New York was geared towards the securities analysts and investment banks in New York, and I don't recall media attending . . . . The format of the presentation in New York was as close to identical to what took place in London as possible. Obviously the venue was different and therefore the layout of the room might be slightly different [but] the substance of the presentation was identical." (Dep. pg. 103:19-22, 104:16-20)

8. EP Business Presentations

a) Shell's Exploration and Production business occasionally made additional presentations during the year, to address specific aspects of its business. For example, the Exploration and Production business held EP Business Presentations in April 1999, April 2000, September 2001, and March 2003. With one exception, all of these presentations took place first in Europe before being repeated in the United States.

(1) *See* van der Steenstraten Decl. ¶ 7(a).

b) The presentation in April 1999 took place first in New York and was followed a day later by a similar presentation at Shell's global EP headquarters in Rijswijk, the Netherlands. The April 1999 presentation was the only one during the Class Period that was conducted first in the United States before being repeated in Europe. But Shell already had disclosed all of the key proved reserves information and related data mentioned in this presentation before the New York presentation took place. The prior disclosure had occurred either (i) through a press release that was simultaneously issued from Shell's IR offices in London and The Hague to stock exchanges and wire services around the world or (ii) in IR announcements and presentations in Europe. *See, infra*, Section V.D.

c) The presentation in April 2000, which was combined with a presentation by Shell's Gas and Power business, took place first in The Hague, followed a day later by a similar presentation in Houston. The presentation in September 2001 took place first in London and was followed a day later by a similar presentation in New York. The presentation in March 2003, which was combined with a presentation by Shell's Gas and Power business, took place first in London was followed a day later by a similar presentation in New York.

(1) *See* van der Steenstraten Decl. ¶7

(2) *See* Henry Decl. ¶¶ 32-35.

d) The direct remarks and presentation materials for Group Strategy Presentations and EP Business Presentations were mainly prepared and approved by IR personnel in London and The Hague.

e) The New York IR office was responsible only for preparing the presentation materials for the portion of presentations addressing Shell's Chemicals business. The New York IR office was not responsible for the portions of presentations addressing Shell's Exploration and Production business. Those portions of presentations were prepared by IR personnel in either London or The Hague.

(1) Sexton

(a) "A: Each of us was sort of the main focal point for a particular line of business in our company. My particular responsibility was chemicals … Q: Do you remember who was responsible for the presentations materials concerning the Oil Business? A: If you're referring to the Upstream Business, the E&P Business . . . for a while it was a gentleman in the UK, Michael Harrop, and then it switched to the gentleman in The Hague, Bart van der Steenstraten." (Dep. pg. 67:3-6, 67:15-23)

(b) "The direct remarks and presentation materials for the Group Strategy Presentations and EP Business Presentations were prepared and approved by Investor Relations personnel in London and The

Hague. For Group Strategy Presentations, I was responsible for preparing the presentation materials for the portion of the presentation addressing Shell's Chemicals business. I was not responsible for the portions of the presentation addressing Shell's Exploration and Production business. Those portions of the presentation were prepared by Investor Relations personnel in either London or The Hague." (Decl. ¶ 13b)

f) The briefing materials for the Group Strategy Presentations and EP Business Presentations were initially prepared by the business units themselves and were later finalized and approved by IR personnel in London and The Hague.

(1) Henry

(a) "Q. Were sample or likely questions drafted for review by the speakers . . . at those presentations? A. Yes, they were. Q. Were you involved in the drafting of those questions? A. Frequently, yes. . . . Q. Were proposed answers to those questions also prepared by IR? A. Yes, they were, although we did not necessarily originate all of those. If they were Business-specific, typically the answer would originate in the Business, be reviewed and commented on by IR in exactly the same way that the prepared speech would be. (Dep. pg. 136:8-137:16)

(2) Sexton

(a) "The briefing materials for the Group Strategy Presentations and EP Business Presentations were initially prepared by the business units themselves and were later finalized and approved by Investor Relations personnel in London and The Hague." (Decl. ¶ 13c)

9. Annual Reports

a) Each year during the Class Period, Royal Dutch and Shell Transport released their respective Annual Reports in March or April. Two versions of the Annual Report were published: a long-form version and a short-form summary version. Both versions of the Royal Dutch Annual Report were published in both English and

Dutch. Both versions of the Shell Transport Annual Report were published in English only.

b) Each long-form Annual Report included, as unaudited supplemental information to the Group's financial statements, information on the Group's proved oil and gas reserves and on RRR for the year. Those long-form Annual Reports were prepared and approved in The Netherlands and United Kingdom, printed in the United Kingdom, and posted on Shell's website from London or The Hague.

c) Similarly, each short-form summary version of the Annual Report was prepared and approved in The Netherlands and United Kingdom, printed in the United Kingdom, and, beginning with the 2000 Annual Report, posted on Shell's website from London or The Hague. The short-form summary versions did not contain the same unaudited supplemental information on proved reserves that appeared in the long-form version, but they did contain a short summary of year-end proved reserves. Before the short-form 2003 Annual Report, the short-form version did not state the RRR for the year.

d) Each year during the Class Period, either a long-form or short-form version of the Annual Report was sent from the London and The Hague IR offices to shareholders who (*i*) were registered, (*ii*) had requested a copy of the report, or (*iii*) were beneficial owners in the United States (except for those beneficial owners who had indicated that they did not wish to receive such reports). Shell normally sent the short-form version to these shareholders, except where particular shareholders had specifically requested the long-form version.

e) Royal Dutch and Shell Transport officially reported the Group's proved reserves to the SEC in an Annual Report filed on SEC Form 20-F. Each year, both companies filed the same Form 20-F with the SEC. The reports were prepared and approved in London and The Hague and were filed from the IR offices in London and The Hague. The proved-reserves figures in those filings were the same as those in the previously distributed long-form Annual Reports. For most years the Class Period, the Annual Reports were published in The Hague and London several days before the Forms 20-F were filed with the SEC. The only exception was for the year 2001, when the Annual Reports were published and the Forms 20-F were filed on the same date.

(1) *See* van der Steenstraten Decl. ¶ 8.

(2) *See* Henry Decl. ¶¶ 22-27.

10. One-on-One Meetings, Field Trips, and Stand-Alone Presentations

a) Shell also engaged in three further types of investor and analyst communications that occasionally included information on Shell's proved oil and gas reserves: one-on-one meetings, field trips, and stand-alone presentations.

(1) One-on-One Meetings

(a) Each year during the Class Period, senior Shell executives participated in one-on-one meetings, also known as "road shows," with large shareholders and analysts in the United Kingdom, Continental Europe, and the United States. These one-on-one meetings generally took place after the 4th Quarter QRA presentations and Group Strategy Presentations, although on certain occasions they also took place at other times throughout the year. During these meetings, Shell did not disclose any market-sensitive or proved-reserves information that it had not previously released to the market.

(i) *See* van der Steenstraten Decl. ¶ 5d.

(ii) *See* Henry Decl. ¶¶ 37-40.

(b) While the New York IR office was involved in the preparation of briefing materials used for one-on-one meetings conducted in the United States, the New York IR Office did not prepare or approve the briefing materials for one-on-one meetings in Europe.

(i) Henry

(ii) "Q. Now, directing your attention again specifically to the follow-up meetings conducted in the United States, in preparation for meeting with specific investors, were briefing notes provided to Shell management? A. Yes, they were. Q. Who prepared those materials? A. My team. Q. Would that have included Mr. Sexton? A. Yes, it would. . . . Q. Conversely, was Mr. Sexton involved in the preparation of briefing materials utilized for the follow-up meetings conducted in Europe? A. Not really." (Dep. pg. 161:24-163:3)

(iii) "The briefing materials for the one-on-one meetings in the United States were prepared by the IR offices in both New York and Europe. While it may have compiled information concerning United States operations that was later included in European presentations and discussions, however, the New York office did not participate in preparing briefing materials for one-on-one meetings in Europe." (Decl. ¶ 41)

(c) The one-on-one meetings were designed for investors and analysts who lived or worked where the meetings were held. Thus, Shell held separate meetings outside the United States for non-U.S. investors and analysts, and inside the United States for U.S.-based investors and analysts. No one-on-one meetings were held in the United States with European-based investors or analysts.

(i) *See* Henry Decl. ¶38, 40.

(2) Field Trips

(a) During this period, Shell also conducted two "field trips" that brought both buy-side and sell-side analysts to some of Shell's operating locations around the world. In September 1999, a field trip went to Egypt, Germany, and The Netherlands. In October 2002, a field trip went to Shell's offices in Houston and to Shell's oil-sands project in Canada.

(b) The 2002 trip focused on the Canadian oil-sands project, which was a major strategic venture for Shell and was unfamiliar to European analysts. Shell was eager to have the European analysts understand the project, because it was a major investment that would produce oil, even though the oil would not count as proved reserves under SEC regulations. Having decided to bring the European analysts to North America, Shell then added a first stop in Houston, to allow the "downstream" businesses (which do not have, estimate, or report proved reserves) to discuss their operations with the analysts.

(i) Henry

(ii) "... so 2002 was an opportunity to take analysts to the Oil Sands activity in Canada, which was a major strategic place for Shell ... and it was particularly for the European analysts who knew little or nothing about the Oil Sands activity in Canada . . . Having decided to take them to Canada, . . . we felt it would be worthwhile doubling up the locations and going to Houston to let the Downstream guys talk about the Downstream Business." (Dep. pg. 214:5-8, 214:10-12, 214:20-21, 215:6-9)

(c) On the first day of the Houston portion of the field trip, the analysts and investors attended presentations about Shell's downstream operations in the United States (including presentations on Shell's Oil Products and Chemicals businesses) and visited a refinery. On the second day, they attended morning presentations on Shell's Exploration and Production business in the United States and the use of technology within the Exploration and Production business generally. The analysts and investors then flew to Canada that afternoon.

(i) *See* Henry Decl. ¶ 45.

(d) According to the head of Shell's IR department (Mr. Henry), it is possible that the subject of Shell's RRR came up during conversations with analysts, but it is unlikely that Shell representatives and the analysts discussed Shell's as-reported proved reserves. In any event, Shell did not disclose during these presentations any market-sensitive or proved-reserves information that it had not previously released to the market from Europe.

(i) Henry

(ii) "Q: During the course of your various conversations with analysts during that field trip, do you recall discussing Shell's

Reserves Replacement Ratio? A: I don't recall specifically, but given the timing, it's quite possible that that subject was discussed. . . . Q: As distinct from the Reserves Replacement Ratio, do you recall if the issue of proved reserves came up during the course of any of your conversations with analysts or investors during that field trip? A: Do you mean proved reserves as already reported rather than the dynamic ratio of what you add in a given period? Q: . . . First as reported, do you recall if that was discussed? A: I don't recall, but it's unlikely." (Dep. pg. 220:5-11, 222:9-16, 222:18-20)

(iii) "These presentations contained substantially the same information concerning the E&P business that had already been released to the market from Europe. In fact, the internal briefing materials that the Group participants used during the field trip expressly warned them not to make 'significant' or 'price sensitive' disclosures in the context of a private meeting with analysts and investors." (Decl. ¶ 45)

(iv) *See* also van der Steenstraten Decl. ¶ 7(b).

(3) Stand-Alone Presentations

(a) Occasionally, Shell conducted stand-alone presentations in the United States, such as those at investment bank energy conferences. The content of these presentations was almost always derived from Shell's previous disclosures. While a presentation might sometimes touch on a new topic that had not been addressed in a previous presentation, such as developments in Shell's technology, these presentations never contained market-sensitive information or proved-reserves information that had not previously been issued to the market.

(i) *See* Henry Decl. ¶ 42.

D. Review of Reserves-Related Statements

1. In order to determine when and where information related to Shell's proved reserves first entered the worldwide market, Shell reviewed all the IR-related materials included in the evidentiary record presented to the Special Master. This record includes deposition exhibits and documents that Shell and Lead Plaintiff designated pursuant to the Order of Special Master Regarding Submission of Evidentiary Record.

2. The IR-related documents include IR presentations, briefing materials, and regulatory filings, for IR events both inside and outside the United States. Shell analyzed Lead Plaintiff's designated documents and matched their contents to similar or identical information that was previously or simultaneously issued outside the United States. [2]

3. The chart below demonstrates that, whenever information related to Shell's proved reserves was (or might have been) disseminated in the United States, the dissemination occurred simultaneously with or after the dissemination of similar, if not identical, information around the world. In no case was reserves-related information ever disclosed first in the United States.

4. Further detail on Shell's responses to each of the documents related to IR conduct in the United States in the evidentiary record is provided in the chart below.

[2] For the purposes of this review, "Reserves-Related" was defined to mean a statement about proved reserves, reserve replacement ratio ("RRR"), or Return on Average Capital Employed.

COMPARISON OF DOCUMENTS RELATED TO INVESTOR RELATIONS CONDUCT IN THE UNITED STATES

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
4/8-9/1999	EP Presentation to Financial Analysts	New York/ Rijswijk	RJW00710239-RJW00710267	Warren Deposition Exhibit 2

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
12/14/98	Presentation to the Financial Community	London	LON01380388-LON01380443	Shell First Exchange 19
12/14/98	Investor Relations Presentation 14 December 1998	London	LON01380050-LON01380073	Shell First Exchange 20
02/11/99	Fourth Quarter and Full Year 1998 Results Announcement	London/Hague	MISC00009467-MISC00009486	Shell First Exchange 24
02/11/99	1998 Results Presentation	The Hague	LON01390842-LON01390869	Shell First Exchange 25
02/11/99	Full Year Results	The Hague	LON01350721-LON01350778	Shell First Exchange 26
04/08/99	Royal Dutch/Shell Press Release	London/Hague	MISC00012308	Shell First Exchange 29

[1] Plaintiff's Documents comprise deposition exhibits and designated exchange documents. The deposition exhibits are identified by referencing the name of the deponent and the exhibit number. The designated exchange documents are identified by referencing whether the document was included in (1) Plaintiff's First Exchange on May 2, 2007 or (2) Plaintiff's Second Exchange on May 22, 2007.

[2] Shell's Response Documents comprise Shell's designated exchange documents. These documents are identified by referencing whether the document was included in (1) Shell's First Document Exchange on May 2, 2007, (2) Shell's Document Exchange in Response to Plaintiff's First Exchange of Documents on May 9, 2007, or (3) Shell's Second Document Exchange on May 22, 2007.

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
4/8-9/1999	Exploration and Production Presentation to Financial Analysts	New York/ Rijswijk	LON01390764-LON01390831	Warren Deposition Exhibit 3
4/8-9/1999	EP Presentation to Financial Analysts	New York/ Rijswijk	SMJ000014615-SMJ000014633	Warren Deposition Exhibit 4

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
12/14/98	Presentation to the Financial Community	London	LON01380388-LON01380443	Shell First Exchange 19
12/14/98	Investor Relations Presentation 14 December 1998	London	LON01380050-LON01380073	Shell First Exchange 20
02/11/99	Fourth Quarter and Full Year 1998 Results Announcement	London/Hague	MISC00009467-MISC00009486	Shell First Exchange 24
02/11/99	1998 Results Presentation	The Hague	LON01390842-LON01390869	Shell First Exchange 25
02/11/99	Full Year Results	The Hague	LON01350721-LON01350778	Shell First Exchange 26
04/08/99	Royal Dutch/Shell Press Release	London/Hague	MISC00012308	Shell First Exchange 29
04/08/99	Royal Dutch/Shell Press Release	London/Hague	MISC00012308	Shell First Exchange 29

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
4/8-9/1999	Shell Exploration & Production technology strengths - ready money, new opportunities, long-term value	New York/ Rijswijk	SMJ00033436-SMJ00033463	Warren Deposition Exhibit 5
12/16/99	Investor Relations Presentation to the Financial Community New York, December 16th 1999	New York	DC00001-DC00061	Sexton Deposition Exhibit 1
12/16/99	Welcome and Opening Remarks	New York	LON0142042-LON01420483 (SMJ00011413-SMJ00011462)	Sexton Deposition Exhibit 2 (same as Plaintiff's First Exchange 50)

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
12/14/98	Presentation to the Financial Community	London	LON01380388-LON01380443	Shell First Exchange 19
12/14/98	Investor Relations Presentation 14 December 1998	London	LON01380050-LON01380073	Shell First Exchange 20
12/15/99	Investor Relations Presentation to the Financial Community	London	LON01390697-LON01390753	Shell First Exchange 40
04/07/99	Royal Dutch Petroleum Company Annual Report 1998	The Hague	HAG00391236-HAG00391312	Shell First Exchange 28
04/07/99	Shell Transport and Trading, p.l.c. Annual Report 1998	London	MISC00080137-MISC00080210	Shell First Exchange 2
12/15/99	Investor Relations Presentation to the Financial Community	London	LON01390697-LON01390753	Shell First Exchange 40

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])

Date	Description	Location of IR Event	Bates	Document Designation
Welcome and Opening Remarks (continued)				
2/10/2000	Royal Dutch/Shell Petroleum Company Full Year Results 10 February 2000	The Hague	SMJ00011513-SMJ00011541	Plaintiff's First Exchange 51 (same as Shell First Exchange 52)
4/11/2000	Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, Public Limited Company Annual Report on Form 20-F 1999	Washington	RJW00101976-RJW00102118	Gardy Deposition Exhibit 2

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])

Date	Description	Location of IR Event	Bates	Document Designation
12/15/99	Third Quarter Results Investor Relations Meeting 15 December 1999	London	LON01420395-LON01420428	Shell First Exchange 41
02/10/00	Full Year Results	The Hague	LON01420004-LON01420032	Shell First Exchange 52 (same as Plaintiff's First Exchange 51)
This document is the transcript of the analyst presentation for the Fourth Quarter and Full Year 1999 Results Announcement. The presentation was held in The Hague and was available for the first time via webcast. Therefore, Shell has no response to this document because the document does not demonstrate investor relations-related conduct in the United States.				
Mar-96	Royal Dutch Petroleum Company Annual Report 1995	The Hague	MISC000090001-MISC000090067	Shell Second Exchange 1
Mar-96	Shell Transport and Trading, p.l.c. Annual Report 1995	London	MISC000090068-MISC000090142	Shell Second Exchange 2
Mar-97	Royal Dutch Petroleum Company Annual Report 1996	The Hague	MISC000090143-MISC000090207	Shell Second Exchange 3

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, Public Limited Company Annual Report on Form 20-F 1999 (continued)				

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
Mar-97	Shell Transport and Trading, p.l.c. Annual Report 1996	London	MISC000090208-MISC000090275	Shell Second Exchange 4
04/03/98	Royal Dutch Petroleum Company Annual Report 1997	The Hague	MISC00080069-MISC00080136	Shell Second Exchange 5
04/03/98	Shell Transport and Trading, p.l.c. Annual Report 1997	London	MISC00080001-MISC00080068	Shell Second Exchange 6
04/07/99	Royal Dutch Petroleum Company Annual Report 1998	The Hague	HAG00391236-HAG00391312	Shell First Exchange 28
04/07/99	Shell Transport and Trading, p.l.c. Annual Report 1998	London	MISC00080137-MISC00080210	Shell First Exchange Response 2
02/10/00	Fourth Quarter and Full Year 1999 Results Announcement	London/The Hague	MISC00012967-MISC00012955	Shell First Exchange 50
02/10/00	Fourth Quarter and Full Year 1999 Results - Presentation	The Hague	LON01320676-LON01320703	Shell First Exchange 51
02/10/00	Full Year Results	The Hague	LON01420004-LON01420032	Shell First Exchange 52
03/31/00	Royal Dutch Petroleum Company Annual Report 1999	The Hague	MISC00004166-MISC00004229	Shell First Exchange 54

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, Public Limited Company Annual Report on Form 20-F 1999 (continued)				
4/12-13/2000	Improving performance and maximizing value in uncertain times	The Hague/ Houston	SMJ00011690-SMJ00011802 (LON01321105-LON01321219)	Plaintiff's First Exchange 52 (same as Warren Deposition Exhibit 7) (same as Shell First Exchange 58)

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
03/31/00	Shell Transport and Trading, p.l.c. Annual Report 1999	London	MISC00080211-MISC00080274	Shell First Exchange Response 3
03/31/00	Royal Dutch Petroleum Company Annual Report 1999	The Hague	MISC00004166-MISC00004229	Shell First Exchange 54
03/31/00	Shell Transport and Trading, p.l.c. Annual Report 1999	London	MISC00080211-MISC00080274	Shell First Exchange Response 3
04/12/00	Press Release	London/The Hague	MISC00004400-MISC00004402	Shell First Exchange 57
4/12-13/2000	Exploration & Production, Gas and Power Presentation to Financial Analysts	The Hague/ Houston	LON01380946-LON01381059	Shell First Exchange 58 (same as Warren Exhibit 7) (same as Plaintiff's First Exchange 52)

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
04/13/00	EP/GP Investor Relations Presentation 12-13th April 2000	Houston	SMJ00038407-SMJ00038454	Warren Deposition Exhibit 6

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
12/14/98	Investor Relations 14 December 1998 Presentation	London	LON01380050-LON01380073	Shell First Exchange 20
10/04/99	Royal Dutch/Shell Group of Companies 4th October 1999 Munchen	Munich	LON01390957-LON01390980	Shell First Exchange 36
12/15/99	Investor Relations Presentation to the Financial Community	London	LON01390697-LON01390753	Shell First Exchange 40
12/15/99	Third Quarter Results Investor Relations Meeting 15 December 1999	London	LON01420395-LON01420428	Shell First Exchange 41
03/31/00	Royal Dutch Petroleum Company Annual Report 1999	The Hague	MISC00004166-MISC00004229	Shell First Exchange 54
03/31/00	Shell Transport and Trading, p.l.c. Annual Report 1999	London	MISC00080211-MISC00080274	Shell First Exchange Response 3
04/12/00	Press Release	London/The Hague	MISC00004400-MISC00004402	Shell First Exchange 57

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])

Date	Description	Location of IR Event	Bates	Document Designation
EP/GP Investor Relations Presentation 12-13th April 2000 (continued)				
04/13/00	Shell EP/GP Investor Presentation	Houston	SMJ00011803-SMJ00011903	Plaintiff's First Exchange 53

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])

Date	Description	Location of IR Event	Bates	Document Designation
4/12-13/2000	Exploration & Production, Gas and Power Presentation to Financial Analysts	The Hague/Houston	LON01380946-LON01381059	Shell First Exchange 58 (same as Plaintiff's First Exchange 52)
In addition, Simon Henry testified that the prepared remarks used at presentations in the United States were the same prepared remarks used at the corresponding presentation held in Europe the previous day. *See* Henry Dep. pg. 141:17-142:3.				
12/14/98	Investor Relations 14 December 1998 Presentation	London	LON01380050-LON01380073	Shell First Exchange 20
10/04/99	Royal Dutch/Shell Group of Companies 4th October 1999 Munchen	Munich	LON01390957-LON01390980	Shell First Exchange 36
12/15/99	Investor Relations Presentation to the Financial Community	London	LON01390697-LON01390753	Shell First Exchange 40
12/15/99	Third Quarter Results Investor Relations Meeting 15 December 1999	London	LON01420395-LON01420428	Shell First Exchange 41
03/31/00	Royal Dutch Petroleum Company Annual Report 1999	The Hague	MISC00004166-MISC00004229	Shell First Exchange 54

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
Shell EP/GP Investor Presentation (continued)				
12/18/00	Investor Relations Presentation	London	LON01350779-LON01350827	Sexton Deposition Exhibit 4
06/11/01	Business Strategies for Deepwater	New York	SMJ00038394-SMJ00038406	Plaintiff's First Exchange 92

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
03/31/00	Shell Transport and Trading, p.l.c. Annual Report 1999	London	MISC00080211-MISC00080274	Shell First Exchange Response 3
04/12/00	Press Release	London/The Hague	MISC00004400-MISC00004402	Shell First Exchange 57
4/12-13/2000	Exploration & Production, Gas and Power Presentation to Financial Analysts	The Hague/ Houston	LON01380946-LON01381059	Shell First Exchange 58 (same as Plaintiff's First Exchange 52)
This document is the transcript of a presentation held in London. Although the face of the document references both London and New York, this presentation was held in London. Therefore, Shell has no response to this document because the document does not demonstrate investor relations-related conduct in the United States.				
12/15/99	Investor Relations Presentation to the Financial Community	London	LON01390697-LON01390753	Shell First Exchange 40
In addition, as explained previously in Shell's Reply Memorandum in Support of their Motion to Dismiss in Part for Lack of Subject Matter Jurisdiction (page 19), the CWC conference was designed for professionals in the oil and gas industry. This conference was not directed at investors or analysts and, thus, this document is not evidence of United States conduct by Shell's Investor Relations function. Furthermore, generally speaking, the document does not contain information related to proved reserves not already disseminated previously at presentations in Europe.				

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
07/10/01	Email from L. Brass to D. Gardy	N/A	V00230112-V00230115	Gardy Deposition Exhibit 5
Oct-01	Management/Market Analaysis & Perception Study	N/A	LON01131370-LON01131445	Plaintiff's First Exchange 11
12/17-18/2001	Investor Relations Presentation - December 2001 London, New York	London/New York	SMJ00012734-SMJ00012832	Plaintiff's First Exchange 54 (same as Shell's First Exchange 92)

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
Plaintiff's document is an email string beginning with an email from Michael Harrop to Simon Henry dated July 9, 2001 in which Mr. Harrop references a "NY transcript." The email also contains extracts from an unidentified presentation given by Phil Watts. After further investigation, we have determined that the extracts were taken from the Group Strategy Presentation as cited immediately below.				
12/18/00	Investor Relations Presentation	London	LON01350779-LON01350827	Sexton Exhibit 4
This document discusses Shell's Investor Relations program in the United States and contains extracts from interviews with analysts from the United States. Shell has no response to this document because the document is not evidence of the dissemination of proved reserves information in the United States.				
09/19/01	Press Release	London/The Hague	MISC00005151	Shell's First Exchange 86
09/19/01	Exploration and Production Presentation to Analysts	The Hague	LON01300816-LON01300864	Shell's First Exchange 87
12/17-18/2001	Investor Relations Presentation	London/New York	LON01301057-LON01301155	Shell's First Exchange 92 (same as Plaintiff's First Exchange 54)
12/17/01	Investor Relations Presentation	London	LON01301004-LON01301056	Shell's First Exchange 93

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
12/18/01	Royal Dutch/Shell Group of Companies Investor Relations Presentation	New York	MISC00012040-MISC00012099 (SMJ00012886-SMJ00012945)	Plaintiff's First Exchange 13 (same as Plaintiffs First Exchange 55)
01/09/2002	CMD 15 January 2002 IR Plan for 2002	N/A	LON00940595-LON00940608	van de Vijver Deposition Exhibit 45
02/13/02	UBS Warburg Energy Conference	New York	SMJ00017220-SMJ00017261	Sexton Deposition Exhibit 5

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
09/19/01	Royal Dutch/Shell Group of Companies Exploration and Production Presentation to Analysts	The Hague	LON01300865-LON01300903	Shell First Exchange 88
12/17-18/2001	Investor Relations Presentation	London/New York	LON01301057-LON01301155	Shell's First Exchange 92 (same as Plaintiff's First Exchange 54)
12/17/01	Investor Relations Presentation	London	LON01301004-LON01301056	Shell's First Exchange 93
This Note for Information ("NFI") discusses in general terms Shell's investor relations program in 2002, including the timing and location of Strategy Presentations and EP Business Presentations, industry conference presentations, quarterly reporting presentations, and one-on-one meetings. Shell's response to this document generally is that, in addition to discussing investor relations events in the United States, this NFI itself is also evidence of the importance of Shell's investor relations program outside the United States. Further, this document is not evidence of the dissemination of proved reserves information in the United States.				
12/17-18/2001	Investor Relations Presentation	London/New York	LON01301057-LON01301155	Shell's First Exchange 92
12/17/01	Investor Relations Presentation	London	LON01301004-LON01301056	Shell's First Exchange 93

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
UBS Warburg Energy Conference (continued)				
2/22/2002	To Phil; One-on-one meetings	London	MISC00020526-MISC00020535	Plaintiff's First Exchange 18

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
02/07/02	Fourth Quarter and Full Year 2001 Results Announcement	London/The Hague	LON01330490-LON01330510	Shell First Exchange 103
02/07/02	2001 Results Presentation to the Press	London	LON01110173-LON01110218	Shell First Exchange 104
02/07/02	Fourth Year and Full Year Results for 2001 Conference	London	LON01110244-LON01110273	Shell First Exchange 105
After further investigation, we have determined that although the face of this document suggests that its date is February 22, 2001, these meetings were held on February 22, 2002. *See*, for example, pages bates-stamped MISC00020528-MISC00020531 which all contain references to prior meetings held in "February 2001." *See* also Shell's First Exchange Response 8 which is an agenda for these meetings held on February 22, 2002. The document consists of briefing materials written by Michael Harrop for Phil Watts in advance of one-on-one meetings in London. However, the materials also reference a "recent" meeting that Mr. Watts attended with Fidelity in the United States. After further investigation, we have determined that the date of this Fidelity meeting in the United States was August 3, 2001. *See* MISC00020924-MISC00020927. Accordingly, Shell's response to this evidence of investor relations conduct in the United States presented by Plaintiff's document is the agenda and notes for a prior one-on-one meeting that Mr. Watts had with Morley Fund Management in London on February 7, 2002. These documents are cited below.				
02/12/01	Morley Fund Management	London	MISC00021041-MISC00021042	Shell First Exchange Response 4
02/12/01	Morley Fund Management Shell International	London	MISC00021039-MISC00021040	Shell First Exchange Response 5

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	**Description**	**Location of IR Event**	**Bates**	**Document Designation**
To Phil; One-on-one meetings (continued)				
5/1/2002	ICC Press Activities	Denver	ID: 200000005783071	Plaintiff's Second Exchange 49
5/1/2002	MGDPW ICC Press Itinerary	Denver	ID: 200000005783071	Plaintiff's Second Exchange 50

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	**Description**	**Location of IR Event**	**Bates**	**Document Designation**
	Limited			
02/22/02	1-1 Meetings - MGDPW	London	MISC00030177	Shell First Exchange Response 8
This document comrpises a media schedule for Phil Watts in Denver. A tentative interview is scheduled with the New York Bureau Chief of the Financial Times. The schedule states that the focus of the interview will be "highlights of Shell U.S. business activities and the importance of the U.S. market to Shell." Shell's response is: (i) Shell maintained an extensive press interview program outside the United States (*see* Henry Exhibit 6/Sexton Exhibit 6 at MISC00021765); and (ii) this document is not evidence of the communication of proved reserves and related information in the United States.				
This document comprises an email discussing Phil Watts' media schedule in Denver. A tentative interview is scheduled with the New York Bureau Chief of the Financial Times. Shell's response is: (i) Shell maintained an extensive press interview program outside the United States (*see* Henry Exhibit 6/Sexton Exhibit 6 at MISC00021765); and (ii) this document is not evidence of the communication of proved reserves and related information in the United States.				

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
7/4/2002	Capital Group Investors Meeting Thursday 4th of July 2001	London	MISC00021585-MISC00021586	Plaintiff's First Exchange 20
8/30/2002	Note for Information - Investor Relations Programme Enhancement: Status update	N/A	ID: 103676010	Plaintiff's Second Exchange 9

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
The document consists of a note from Michael Harrop to Phil Watts describing a visit by Capital Guardian to London. However, the document also references a "relatively recent[ ]" visit by Walter van de Vijver to Capital in New York. Other documents indicate that this meeting took place on April 19, 2002. *See* Henry Exhibit 6/Sexton Exhibit 6. Accordingly, Shell's response document is an agenda of previous meetings held in London on February 22, 2002 and is cited below.				
02/22/02	1-1 Meetings - MGDPW	London	MISC00030177	Shell First Exchange Response 8
The Note for Information ("NFI") discusses, amongst other things, targeting investors in the United States. The NFI also includes an IR Programme proposal which mentions the September 2002 west coast road-show, the October 2002 field trip to Houston, and the February 2003 combined 4th Quarter QRA presentation and Strategy Presentation that was repeated in New York, all of which are investor relations events in the United States that Plaintiff has identified through the introduction of deposition exhibits or exchange documents. Shell's responses to each of the United States investor relations events referenced in this document are shown elsewhere in this chart. *See* Shell's responses to: Henry Deposition Exhibit 6/Sexton Deposition Exhibit and Plaintiff's First Exchange 10 (Sept 2002 west coast road show); Plaintiff's First Exchange 77, Darley Deposition Exhibit 12, and Plaintiff's Second Exchange 12 (October 2002 field trip); and Plaintiff's First Exchange 56 and Plaintiff's First Exchange 14 (QRA and Strategy Presentation). Furthermore, Shell's response to this document generally is that, in addition to discussing the United States market, the NFI itself is also evidence of the importance to Shell of markets outside the United States. For example, the NFI states that "based on potential to invest new money and identify new investors, Continental Europe was identified for 2002 as the most promising market." The NFI also refers to the "relatively untapped" market in Japan and references one-on-one meeting roadshows in the United Kingdom, Scotland, Germany, and Scandinavia.				

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
9/9/2002	Forbes Interview	Los Angeles	ID: 200000005782388	Plaintiff's Second Exchange 51
09/12/02	US West Coast Briefing Materials	West Coast	MISC00021660-MISC00021788	Henry Deposition Exhibit 6 (same as Sexton Deposition Exhibit 6)
9/16/2002	US West Coast Investors Road Show 16-18 September 2002	West Coast	LON00961041-LON00961057	Plaintiff's First Exchange 10

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
This document comprises media briefing materials in advance of an interview in Los Angeles between Phil Watts and Forbes magazine. Shell's response is: (i) the materials themselves state that the interview will focus on Shell in North America; (ii) the materials consist of summaries of Shell's businesses in the United States, the Athabasca oil sands in Canada, and the Altimira and Baja fields in Mexico, none of which previously had booked reserves that were subsequently recategorized; (iii) the information was prepared by investor relations personnel in London and The Hague; (iv) the key messages section was also used as briefing material for prior one-on-one meetings in Europe (*see* Plaintiff's First Exchange 18 at MISC00020532); (v) Shell also maintained an extensive press interview program outside the United States (*see* Henry Exhibit 6/Sexton Exhibit 6 at MISC00021765).				
This document comprises briefing materials only. As these are briefing or preparatory materials, it is not clear what, if any, evidence of investor relations conduct in the United States is being presented on the basis of this document. Therefore, there is no Shell response document because there is no evidence that any of this information in these materials was diseminated during the meetings in the United States. Moreover, these types of materials were prepared and approved in the London or The Hague Investor Relations offices.				
This document is a summary of a series of one-on-one meetings held on the west coast of the United States. As listed below, Shell's response comprises (1) meeting notes from three one-on-one meetings previously held in Zurich, and (2) Shell's Second Quarter 2002 Results Announcement. Together, these documents demonstrate that the substance of the information related to proved reserves discussed during the "west coast meetings" was issued previously in Europe and that Shell had a similar and significant one-on-one meeting program throughout Europe.				
07/04/02	Group Lunch (Zurich)	Zurich	MISC00030718	Shell First Exchange Response 10

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
US West Coast Investors Road Show 16-18 September 2002 (continued)				
09/19/02	Email from J. Darley to M. Leonard re AG Edwards analyst meeting	Boston	ID:104117803 and 106546700	Darley Deposition Exhibit 11
10/7/2002	Investor Relations USA and Canada Field Trip Briefing Materials for Shell Participants	Houston/ Canada	SMJ00033159-SMJ00033220	Plaintiff's First Exchange 77

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
07/04/02	Swiss Re (Zurich)	Zurich	MISC00021888	Shell First Exchange Response 11
07/04/02	Julius Baer (Zurich)	Zurich	MISC00021892	Shell First Exchange Response 12
08/01/02	Royal Dutch/Shell Group of Companies 2nd Quarter 2002 Results	London/The Hague	MISC00011031-MISC00011050	Shell First Exchange Response 13
09/19/01	Exploration and Production Presentation to Analysts	The Hague	LON01300816-LON01300864	Shell First Exchange 87
08/01/02	2002 Half Year Results and Performance Review	London	LON01382214-LON01382242	Shell First Exchange 116
08/01/02	Royal Dutch/Shell Group of Companies 2nd Quarter 2002 Results	London/The Hague	MISC00011031-MISC00011050	Shell First Exchange Response 13
08/01/02	2002 Half Year Results and Performance Review	London	LON01151059-LON01151091	Shell First Exchange 115

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
Investor Relations USA and Canada Field Trip Briefing Materials for Shell Participants (continued)				
10/08/02	Presentation by John Darley, Director, Shell Technology E&P	Houston	SMJ00035555-SMJ00035564	Darley Deposition Exhibit 12
10/13/02	IR field trip October 7-9	Houston/ Canada	ID: 107795414	Plaintiff's Second Exchange 12

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
08/01/02	2002 Half Year Results and Performance Review	London	LON01382214-LON01382242	Shell First Exchange 116
This document is the script for a presentation by John Darley at the analyst field trip in Houston. The script describes different technologies and explains how technology supports the Exploration and Production business. There were no representations made in this presentation regarding proved reserves, RRR, or ROACE. Therefore, there are no Shell response documents.				
This document is a report describing the analyst field trip to Houston and Canada. The report states that the field trip in Houston comprised six presentations on Shell's Oil Products business, 1 presentation on Shell's Chemicals business, 1 presentation on Shell's Exploration and Production in the United States, and 1 presentation on Global Exploration and Production Technology. Also, the report states that "[s]tock exchange releases were issued on Monday and Tuesday mornings, describing the key elements from the presentations of that day." Shell's response is that it did not disclose in these presentations any market sensitive information or proved reserves information that it had not previously released to the market, either through the stock exchange releases mentioned in the report or in the previous presentations cited below.				
08/01/02	Royal Dutch/Shell Group of Companies 2nd Quarter 2002 Results	London/The Hague	MISC00011031-MISC00011050	Shell First Exchange Response 13
08/01/02	2002 Half Year Results and Performance Review	London	LON01151059-LON01151091	Shell First Exchange 115

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
IR field trip October 7-9 (continued)				
11/01/2002	Enhancing Shell's Value Through Better Communications	N/A	N/A	Jacobi Deposition Exhibit 2
11/4/2002	US Meeting programme proposal: November 4th to 7th 2002	New York/ Boston	MISC00021771 (SMJ00003041)	Plaintiff's First Exchange 19 (same as Plaintiff's First Exchange 72)

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
08/01/02	2002 Half Year Results and Performance Review	London	LON01382214-LON01382242	Shell First Exchange 116
10/7-8/02	Stock exchange releases	The Hague	MISC00005842-MISC00005847	Shell Second Exchange Response 2
This document is a presentation prepared by Taylor Rafferty. It includes, amongst other things, a comparison of investors from Continental Europe, the United Kingdom, and the United States, and a discussion of U.S. retail investors. Shell's response to this document generally is that it is evidence of the importance to Shell of investors both outside and inside the United States. This document also includes an overview of financial media that mentions media entities from the United States, such as Bloomberg, CNN, CNBC, the New York Times, and the Wall Street Journal. Shell's response to this is to refer to the deposition testimony of Mary Jo Jacobi in which Ms. Jacobi states that Shell communicated with the London bureaus of these U.S. media entities. *See* Jacobi Dep. pg. 21:9-16, 22:3-8, 140:1-2. *See* also Henry Dep. pg. 55:13-15, 55:19-56:5.				
05/13/02	Roadshow Manual, Scotland - Monday, 13th May 2002	Edinburgh	MISC00021316-MISC00021321	Shell First Exchange Response 9

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
11/06/02	Jeroen van der Veer one-on ones	New York	SMJ00003541-SMJ00003561 (HAG00332080-HAG00332100)	Henry Deposition Exhibit 8 (same as Sexton Deposition Exhibit 7)
02/10/03	Email from J. Pay to S. Henry	N/A	V00310347-V00310348	Henry Deposition Exhibit 14 (same as Sexton Deposition Exhibit 9)

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
12/17/01	Investor Relations Presentation	London	LON01301004-LON01301056	Shell First Exchange 93
02/07/02	Fourth Quarter and Full Year 2001 Results Announcement	London	LON01110244-LON01110273	Shell First Exchange 105
05/02/02	First Quarter 2002 Results Announcement	London/The Hague	LON01061512-LON01061530	Shell First Exchange 111
08/01/02	2002 Half Year Results and Performance Review	London	LON01151059-LON01151091	Shell First Exchange 115
08/01/02	2002 Half Year Results and Performance Review	London	LON01382214-LON01382242	Shell First Exchange 116
The 108% RRR figure quoted in the February 10, 2003 email was previously publicly disseminated in the United States during the 4th Quarter and Full Year 2002 Results Presentation held in New York on February 7, 2003. The documents below show that this figure was previously disseminated in London on February 6, 2003. In addition, the 85% oil and NGL RRR figure that Henry references in the same email was also disseminated in the 4th Quarter QRA issued from London and The Hague on February 6, 2003.				
02/06/03	Fourth Quarter and Full Year 2002 Results Announcement		LON00011070-LON00011090	Shell First Exchange 138

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])					Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation	Date	Description	Location of IR Event	Bates	Document Designation
Email from J. Pay to S. Henry (continued)					02/06/03	Conference Call Q42002 Royal Dutch Petroleum Co. Earnings	London	MISC00011217-MISC00011244	Shell First Exchange 139
02/06-07/03	2002 - a pivotal year, 4th quarter and full year results, Maintaining momentum in uncertain times, strategy and performance update	London/New York	SMJ00013437-SMJ00013512	Plaintiff's First Exchange 56 (same as Shell's First Exchange 140)	12/17/01	Investor Relations Presentation	London	LON01301057-LON01301155	Shell First Exchange 92
					12/17/01	Investor Relations Presentation	London	LON01301004-LON01301056	Shell First Exchange 93
					08/01/02	Second Quarter 2002 Results Presentation	London	LON01151059-LON01151091	Shell First Exchange 115
					08/01/02	2002 Half Year Results and Performance Review	London	LON01382214-LON01382242	Shell First Exchange 116
					02/06/03	Fourth Quarter and Full Year 2002 Results Announcement	London/The Hague	LON00011070-LON00011090	Shell First Exchange 138
					02/06/03	Conference Call Q42002 Royal Dutch Petroleum Co. Earnings	London	MISC00011217-MISC00011244	Shell First Exchange 139

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])					Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation	Date	Description	Location of IR Event	Bates	Document Designation
2002 - a pivotal year, 4th quarter and full year results, Maintaining momentum in uncertain times, strategy and performance update (continued)					02/06-07/03	Fourth Quarter 2002 and Full Year Results Presentation – "Maintaining momentum in uncertain times"	London/New York	LON01430860-LON01430935	Shell First Exchange 140
2/7/2003	Royal Dutch/Shell Group of Companies Presentation to the Financial Community: 2002 Fourth Quarter and Full-Year Results	New York	MISC00012100-MISC00012152 (SMJ00013541-SMJ00013593)	Plaintiff's First Exchange 14 (same as Plaintiff's First Exchange 57)	02/06/03	Fourth Quarter and Full Year 2002 Results Announcement	London/The Hague	LON00011070-LON00011090	Shell First Exchange 138
					02/06/03	Conference Call Q42002 Royal Dutch Petroleum Co. Earnings	London	MISC00011217-MISC00011244	Shell First Exchange 139
					02/06-07/03	Fourth Quarter 2002 and Full Year Results Presentation – "Maintaining momentum in uncertain times"	London/New York	LON01430860-LON01430935	Shell First Exchange 140
02/07/03	One-on-ones with Phil Watts and Judy Boynton 7-11 February 2003	New York	MISC00030096-MISC00030097	Sexton Deposition Exhibit 8 (same as Henry Deposition Exhibit 13)	This document comprises notes of questions asked during the one-on-one meetings. None of Shell's responses to these questions, however, are recorded in the notes. Therefore, there is no Shell response document because Plaintiffs cannot demonstrate what representations were made by Shell during the meetings.				

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
03/21/03	Royal Dutch Petroleum Company N.V. Koninklijke Nederlandsche Petroleum Maatschappij Annual Report 2002	The Hague	RJW00651259-RJW00651350	Plaintiff's First Exchange 41 (same as Plaintiff's First Exchange 132)
03/21/03	The "Shell" Transport and Trading Company, p.l.c. Annual Report and Accounts 2002	London	No bates	Plaintiff's First Exchange 116 (same as Shell's First Exchange Response 17)
3/26/2003	Exploration and Production Strategy Presentation, March 2003	London/New York	SMJ00013594-SMJ00013654	Plaintiff's First Exchange 58 (same as Shell's First Exchange 145)
3/26-27/2003	Exploration and Production Gas & Power Strategy Presentation	London/New York	SMJ00032515-SMJ00032620	Plaintiff's First Exchange 76

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
This Annual Report was prepared, approved, and published in Europe. *See* Henry Decl ¶¶ 24-25. Therefore, there is no Shell response document because this document does not demonstrate investor relations-related conduct in the United States.				
This Annual Report was prepared, approved, and published in Europe. *See* Henry Decl ¶¶ 24-25. Therefore, there is no Shell response document because this document does not demonstrate investor relations-related conduct in the United States.				
03/21/03	The "Shell" Transport and Trading Company, p.l.c. Annual Report 2002	London	MISC00080343-MISC00080426	Shell's First Exchange Response 17
3/26-27/2003	Exploration and Production Strategy Presentation	London/ New York	LON01051900-LON01051960	Shell's First Exchange 145
3/26-27/2003	Exploration and Production Strategy Presentation	London/ New York	LON01051900-LON01051960	Shell First Exchange 145

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
Exploration and Production Gas & Power Strategy Presentation (continued)				

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
04/06/01	Royal Dutch Petroleum Company Annual Report 2000	The Hague	MISC00004561-MISC00004628	Shell First Exchange 80
04/06/01	The "Shell" Transport and Trading Company, p.l.c. Annual Report 2000	London	MISC00080275-MISC00080342	Shell First Response 7
04/12/02	Royal Dutch Petroleum Company Annual Report 2001	The Hague	MISC00005166-MISC00005241	Shell First Exchange 109
04/12/02	The "Shell" Transport and Trading Company, p.l.c. Annual Report 2001	London	LON01443370-LON01443445	Shell First Exchange 108
02/06/03	Fourth Quarter and Full Year 2002 Results Announcement	London/The Hague	LON00011070-LON00011090	Shell First Exchange 138
02/06/03	Conference Call Q42002 Royal Dutch Petroleum Co. Earnings	London	MISC00011217-MISC00011244	Shell First Exchange 139
03/21/03	Royal Dutch Petroleum Company Annual Report 2002	The Hague	RJW00012607-RJW00012608	Shell First Exchange 143
03/21/03	The "Shell" Transport and	London	MISC00080343-MISC00080426	Shell First Exchange

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
Exploration and Production Gas & Power Strategy Presentation (continued)				
3/27/2003	Strategy Presentation Exploration and Production, Gas & Power	New York	HAG00330059-HAG00330114	Henry Deposition Exhibit 4 (same as Darley Deposition Exhibit 16)

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
	Trading Company, p.l.c. Annual Report 2002			Response 17
02/06/03	Fourth Quarter and Full Year 2002 Results Announcement	London/The Hague	LON00011070-LON00011090	Shell First Exchange 138
02/06/03	Conference Call Q42002 Royal Dutch Petroleum Co. Earnings	London	MISC00011217-MISC00011244	Shell First Exchange 139
02/06-07/03	Fourth Quarter 2002 and Full Year Results Presentation – "Maintaining momentum in uncertain times"	London/New York	LON01430860-LON01430935	Shell First Exchange 140
3/26/2003	Press Release regarding Exploration and Production and Gas & Power Strategy Presentation	London/The Hague	MISC00012607-MISC00012608	Shell First Exchange 144
3/26-27/2003	Exploration and Production Strategy Presentation	London/ New York	LON01051900-LON01051960	Shell First Exchange 145
03/26/03	Exploration and Production, Gas & Power Strategy Presentation	London	LON01381993-LON01382046	Shell First Exchange 146

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])					Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation	Date	Description	Location of IR Event	Bates	Document Designation
04/3-4/03	Investors Meetings in Houston with Walter van de Vijver	Houston	SMJ00005089-SMJ00005093	Plaintiff's First Exchange 48	This document comprises notes of one-on-one meetings attended by Walter van de Vijver in Houston. Shell's response are notes of one-on-one meetings attended by Mr. van de Vijver previously in London (cited below).				
					02/21/03	Merrill Lynch Asset Management (London)	London	MISC00030887-MISC00030889	Shell First Exchange Response 15
					02/21/03	Foreign & Colonial (London)	London	MISC00030861-MISC00030863	Shell First Exchange Response 16
4/23/2003	Note For Discussion Group Investor Relations: Strategy and Plan to mid 2004	N/A	LON00870074-LON00870092	Henry Deposition Exhibit 15 (note that Jacobi Deposition Exhibit 4 is a similar document)	This Note for Discussion ("NFD") discusses, amongst other things, targeting retail investors in the United States. The NFD also includes an IR Program which mentions the February 2003 combined Fourth Quarter QRA presentation and Strategy Presentation that was repeated in New York, and follow-up one-on-one meetings held in New York and Boston, as well as the March 27, 2003 EP Business Presentation which was also repeated in New York. These are all investor relations events in the United States that Plaintiff has identified through the introduction of deposition exhibits or exchange documents. Shell's response to these United States investor relations are shown elsewhere in this chart. *See* Shell's responses to: Plaintiff's First Exchange 56 and Plaintiff's First Exchange 14 (QRA and Strategy Presentation), Sexton Deposition Exhibit 8/Henry Deposition Exhibit 13 (follow-up one-on-one meetings), Plaintiff's First Exchange 58, Plaintiff's First Exchange 76, and Henry Deposition Exhibit 4/Darley Deposition Exhibit 16 (March 2003 EP Business Presentation). Furthermore, Shell's response to this document generally is that, in addition to discussing the United States retail market, the NFD itself is also evidence of the importance to Shell of markets outside the United States. For example, the NFD states that "[t]he US retail and the Japanese institutional investor markets are specific new target markets."				
11/5/2003	Harnessing global strengths to grow value	New York	SMJ00014258-SMJ00014268	Plaintiff's First Exchange 59	3/26-27/2003	Exploration and Production Strategy Presentation	London/ New York	LON01051900-LON01051960	Shell First Exchange 145

Plaintiff's Documents Related to Investor Relations Conduct in the United States (including Deposition Exhibits and Designated Exchange Documents[1])				
Date	Description	Location of IR Event	Bates	Document Designation
Plaintiff's First Exchange 59 (continued)				
2/5-6/2004	Royal Dutch/Shell Companies 2003 4th Quarter and Full Year Results	London/New York	SMJ00014336-SMJ00014356	Plaintiff's First Exchange 60 (same as Shell's First Exchange 161)

Shell's Response to Plaintiff's Documents (including Shell's Designated Exchange Documents[2])				
Date	Description	Location of IR Event	Bates	Document Designation
03/26/03	Exploration and Production, Gas & Power Strategy Presentation	London	LON01381993-LON01382046	Shell First Exchange 146
10/23/03	Third Quarter 2003 Results Announcement	London	MISC00011091-MISC00011109	Shell First Exchange 154
10/23/03	Q3 2003 Royal Dutch/Shell Earnings Conference Call	London	MISC00011349-MISC00011372	Shell First Exchange Response 18
2/5-6/2004	2003 Fourth Quarter and Full Year Results - "Reserves and Exploration and Production Growth Update"	London/New York	LON01092127-LON01092148	Shell First Exchange 161 (same as Plaintiff's First Exchange 60)

TAB 6

FACT SUMMARY

VI. RECATEGORIZATION AND REDUCTION ANALYSIS

During the first half of 2004, Shell voluntarily announced that it intended to recategorize certain proved reserves that previously had been compiled, reviewed, audited, and approved through the ARPR process in the Netherlands and reported to the public from Europe. Virtually all of the recategorized proved reserves were outside the United States and originally had been reported to the Group Reserves Coordinator in the Netherlands by non-U.S. operating units. No previously reported U.S. proved reserves were restated, and only a trivial amount of U.S. proved reserves that Shell had anticipated reporting for 2003 was reduced – just 0.05% of Shell's total reported proved reserves for that year.

A. Prelude to the Recategorization

In the wake of the SEC staff's issuance of its interpretive guidance to try to resolve the "confusion" surrounding the SEC's Rule 4-10, some Shell employees began to question whether the Shell Guidelines were fully aligned with the SEC staff's interpretation of rules on reporting proved reserves. When the Group Reserves Auditor's audits of two operating units in Oman and Nigeria resulted in "unsatisfactory" ratings in September and October 2003, Shell's Committee of Managing Directors authorized an internal review of the company's reported proved reserves' compliance with SEC rules and staff guidance.

This review – called Project Rockford – was run from EP's offices in Rijswijk, the Netherlands. The project began in the midst of the ARPR process for year-end 2003, and it focused on the most significant areas of potential non-compliance with SEC reporting requirements. Shell committed significant resources to identifying and quantifying any instances of noncompliant reserves so any necessary recategorization of reserves could be correctly reflected in the operating units' ARPR submissions by early 2004.

B. **<u>Shell's Recategorization Announcements</u>**

On January 9, 2004, Shell announced preliminary results of Project Rockford and stated that it would be recategorizing 3.9 billion barrels of oil equivalent ("bboe") that previously had been reported as proved for year-end 2002. Shell also disclosed that it was conducting further studies, including analyses to determine the extent to which the recategorization would affect prior years' reported proved reserves.[41]

Subsequently, while finalizing its year-end 2003 reserves data, Shell also determined that certain additional proved reserves that it either had previously reported for prior years or expected to report at year-end 2003 did not fully comply with certain more technical aspects of the SEC staff's interpretation of Rule 4-10. Shell therefore initiated a Major Field Review ("MFR1") of some 80 fields and reservoirs containing 40% of Shell's total proved reserves and 58% of its proved undeveloped reserves (*i.e.*, those that were not presently in production and required material expenditures for production to begin).[42] This review also was run from EP's Rijswijk offices.

On March 18, 2004 – the last day of the Class Period – Shell announced that, as a result of the findings in MFR1, the company would recategorize an additional 0.25 bboe previously reported as proved and that it would not report for year-end 2003 another 0.22 bboe it had expected to report as proved. Shell also said it would further study specific fields identified in MFR1 and would examine its total petroleum portfolio.[43]

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41 *See* Doc. #HAG00190431-33.

42 *See* Doc. #LON00800508-41.

43 *See* Doc. #MISC00012718-22.

These new studies led to certain additional recategorizations of proved reserves, which Shell announced after the end of the Class Period. The total recategorizations reported in Shell's 2003 Annual Report on Form 20-F, filed June 30, 2004, restated previously reported proved reserves as of year-end 2002 by 4.47 bboe and reduced the proved reserves Shell had expected to report for year-end 2003 by about 0.40 bboe.

C. **Reasons for Restatements and Reductions**

Shell's public filings explained that the recategorized reserves previously reported as proved had varied from SEC Rule 4-10 and the SEC staff's interpretation of that Rule in several respects, including (*i*) investment commitment, (*ii*) market assurance, (*iii*) governmental or regulatory approval, (*iv*) field performance and project delivery, (*v*) year-end pricing, (*vi*) technical definition, and (*vii*) royalties. (Items (*i*) through (*iv*) are commonly referred to collectively as "project maturity.")

Investment Commitment. The SEC Staff's June 30, 2000 guidance (the "Staff Guidance") says that proved reserves cannot be reported without "[a] commitment by the company to develop the necessary production, treatment and transportation infrastructure." Shell determined that this commitment should be shown on significant projects through the taking of a "Final Investment Decision" ("FID"), and Shell restated or reduced certain proved reserves where this specific commitment to development actions in the form of an FID was lacking.

Market Assurance. The Staff Guidance requires companies to demonstrate "a reasonable certainty that a market exists for the hydrocarbons" before they can report those reserves as proved. Shell restated or reduced certain proved reserves based on insufficiently certain evidence of future market demand.

Governmental/Regulatory Approval. The Staff Guidance requires consideration of "[t]he history of issuance and continued recognition of permits . . . by regulatory bodies" before proved reserves can be reported. Shell restated or reduced certain proved reserves that had been booked for projects for which governmental or regulatory approvals were not sufficiently assured.

Field Performance/Project Delivery. Shell restated or reduced certain proved reserves for projects whose execution had been deferred or whose actual production volumes and forecasts had declined.

Year-End Pricing. SEC Rule 4-10(a)(2) says that proved reserves must be reasonably certain to be recoverable under "existing economic and operating conditions," based on "prices and costs as of the date the estimate is made." Shell restated or reduced certain reserves that had been reported as proved based on prices that Shell used internally for making investment decisions and for business planning. During the Class Period, EP management and the Group Reserves Coordinator in the Netherlands had required operating units to use Shell's internal pricing model, rather than year-end prices, to estimate their proved reserves. Thus, all proved-reserves bookings that later were restated for a failure to use year-end prices resulted from decisions made in and instructions issued from the Netherlands.

Technical Definition. Shell restated or reduced certain proved reserves because they failed to meet various technical requirements in the Staff Guidance, including:

- the "lowest known hydrocarbon" standard, which says that, in the absence of geological and engineering data delineating the extent of a reservoir, the lower proved limits of a reservoir depend on the "lowest known structural occurrence of hydrocarbons" (this issue was not fully resolved until 2003, in discussions with the SEC staff; accordingly, no reserves were restated based on this new interpretation);
- the "proved area" standard, which says that "proved reserves cannot be claimed more than one offset location away from a productive well if there are no other wells in the reservoir, even though seismic data may exist";
- the "improved recovery" standard, which prohibits reporting proved reserves based on improved-recovery techniques until those techniques "have been proved

effective in that reservoir or an analogous reservoir in the same geologic formation in the immediate area";

- the forecasting-methodology standard, which prohibits reporting proved reserves based on computer modeling unless the modeling is supported by data about actual reservoir performance, and

- the "economic producibility" standard, which prohibits reporting proved reserves absent data showing "economic producibility" and that the reservoir is analogous to similar reservoirs in the same field that have produced or have demonstrated the ability to produce on a formation test.

Royalties. Shell restated or reduced certain proved reserves because it had used an incorrect method of estimating proved reserves attributable to cash payments of royalties. These amounts were announced on May 24, 2004, after the Class Period had ended, and are not the subject of plaintiffs' Complaint.

D. Locations of Restated and Reduced Reserves

The accompanying Declaration of James Cooper contains tables showing the restated or reduced proved reserves for each EP operating unit. The tables show that virtually all of those reserves were from 28 non-U.S. operating units in Abu Dhabi, Angola, Australia, Bangladesh, Brazil, Brunei, Canada, China, Egypt, Gabon, Germany, Iran, Ireland, Italy, Kazakhstan, Malaysia, the Netherlands, New Zealand, Nigeria (two different operating units), Norway, Oman (two different operating units), the Philippines, Russia, Syria, the United Kingdom, and Venezuela. Each of those operating units previously had reported those reserves to the Group Reserves Coordinator in the Netherlands.[44]

No proved reserves in the United States were restated at all for each of year-end 1999, 2000, 2001, or 2002. And only a miniscule portion of the proved reserves that Shell had

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44 Cooper Decl. ¶¶ 34-71, 74-75 and accompanying tables.

expected to report (but had not yet reported) for the United States for 2003 was reduced: just 0.05% of Shell's aggregate 2003 reported proved reserves.[45]

[45] Cooper Decl. ¶¶ 72-73 and accompanying table.

FACT SUPPORT

VI. RESTATEMENT AND REDUCTION ANALYSIS

The country-by-country and year-by-year restatements for 1999 through 2002 are summarized in a chart (the "Summary Chart," attached as Appendix A) that shows (*i*) the volumes restated for the particular country or operating unit, (*ii*) the percentages that those volumes represent of the total volumes restated for that year, and (*iii*) the percentages that the volumes represent of the total volume of proved reserves originally reported for that year.

For 2003, the Summary Chart shows (*i*) the reductions in proved reserves that Shell had previously announced it would report for 2003, (*ii*) the percentages that those volumes represent of the total reductions for 2003, and (*iii*) the percentages that the volumes represent of the total proved reserves reported for 2003. *See infra* Section F.1.

A. Background

1. In late 2003, the Group Reserves Auditor ("GRA") for Shell's Exploration and Production business ("EP") evaluated Petroleum Development Oman ("PDO") and Shell Petroleum Development Company (Nigeria) Limited ("SPDC") as "unsatisfactory" during his audits of their proved reserves, *see supra* Section V.B.

a) The GRA audited SPDC's proved reserves in an abbreviated "process" audit in September 2003 and gave an "unsatisfactory" rating.

(1) Proved Reserves Process Audit – SPDC (Nigeria), 18-19 Sept. 2003, pg. 1.

(a) "The audit finding is therefore that the present status of SPDC's proved oil reserves is unsatisfactory." (emphasis in original) (V00211034-43)

(2) The GRA's audit of SPDC took place in the Netherlands over a two-day period, rather than the typical five or six days for a company the size of SPDC, due to the GRA's inability to travel at that time.

(a) Barendregt

(i) "Q. [H]ow much time did you spend on an audit? A. Typically two or three to five or six days, depending on the size of the company." (Dep. pg. 250:17-22, 251:1-3)

(ii) "I was scheduled to perform my audit of SPDC in Nigeria, as I had in 1999. I was unable to make the trip, however, due to health reasons. . . . The SPDC personnel extended their visit to the Netherlands so that I could conduct my SPDC audit there." (Decl. ¶ 14)

b) The GRA audited PDO's proved reserves in October 2003 in Oman or Muscat and gave an "unsatisfactory" rating. Although the audit took place in late October 2003, the audit report was not issued in its final form until late November 2003.

(1) SEC Proved Reserves Audit – PDO (Oman), 25-28 Oct. 2003, pg. 1.

(a) "The overall opinion on the state of PDO's 1.1.2003 Proved Reserves submission, taking account of the audit's findings . . . , is unsatisfactory." (Emphasis in original) (V00102442-56)

c) Following the "unsatisfactory" audits of SPDC and PDP and the identification of other potentially exposed proved reserves volumes, Sir Philip Watts, Chairman of Shell's Committee of Managing Directors ("CMD"), called for an internal review of Shell's reported proved reserves' compliance with SEC rules and guidance ("Project Rockford"). Watts acted at a meeting of the CMD on December 8 and 9, 2003.

(1) Van de Vijver

(a) "A. Project Rockford was launched by Phil Watts on that first CMD meeting the 9th of December." (Dep. pg. 91:13-18)

2. Project Rockford

a) Project Rockford focused on the most significant areas of Shell's potential non-compliance with SEC proved-reserves reporting requirements. It was led by Watts and Adrian Loader, Director of Strategic Planning, Sustainable Development and External Affairs, and included a representative from EP (John Darley) and representatives from Group Legal and Group Finance.

(1) Van de Vijver

(a) "Q. –[W]hat is your recollection of how that structure [of Project Rockford] worked? . . .

A. Over time a formal structure was put in place. Project Rockford was led by Phil Watts with the assistance of Adrian Loader. And I at that time recommended as the focal point for EP, John Darley. So there was a structure that involved Legal, Group Finance . . . ." (Dep. pg. 525:18-526:9)

B. Recategorization and Reduction Chronology

1. The findings of Project Rockford were announced on January 9, 2004.

a) Shell press release dated January 9, 2004.

(1) "[Shell] announced today that, following internal reviews, some proved hydrocarbon reserves will be recategorised. The total non recurring recategorisation, relative to the proved reserves as stated at December 31st 2002, represents 3.9 billion barrels of oil equivalent ('boe') of proved reserves. . . . Over 90% of the reduction was attributable to proved undeveloped reserves; the balance is a reduction in the proved developed category. . . . There is no material effect on financial statements for any year up to and including 2003. The recategorisation of proved reserves does not materially change the estimated total volume of hydrocarbons in place, nor the volumes that are expected ultimately to be recovered."

(2) "Several factors identified by Shell's own reviews led to the recategorisation. During Q4 2003, a number of in depth reserve studies were completed, which prompted a broad review of its previously booked reserves against current proved reserves standards." (HAG00190431-33)

2. Following the recategorization announcement in January 2004, and as a result of additional proved reserves issues raised in the course of finalizing the 2003 Annual Review of Petroleum Resources ("ARPR") process, Shell initiated two reviews of its major petroleum fields ("Major Field Reviews") for compliance with the SEC's Rule 4-10 of Regulation S-X ("Rule 4-10") and the SEC staff's interpretation thereof.

a) Major Field Review #1 ("MFR1")

(1) MFR1 began in mid-March 2004. It was a three-day review conducted in Rijswijk involving some 80 fields representing 40% of Shell's total proved reserves and 58% of its proved undeveloped reserves (*i.e.*, those that were not currently in production and required material expenditures

for production to begin). EP Reserves Presentation to [Group Audit Committee] ("GAC"), pg. 10, 16.

(2) Reserves specialists from the operating units met with the review team, which consisted of independent petroleum consultants, Shell internal audit staff, Shell external auditors, and Shell reserves consultants. The review team in Rijswijk met with the reserves specialists to consider information regarding selected fields with respect to various factors, including:

(a) Determination of the lateral extent of the proved area, specifically the "one offset location" rule;

(b) How economic producibility was established, for example, through production flow tests, well or core logs, or fluid samples;

(c) The use of reservoir simulation without sufficient analogue reservoir performance data;

(d) The inclusion of improved recovery process reserves where no pilot or area analogue project existed (especially in frontier areas), and

(e) Project maturity and other considerations. EP Reserves Presentation to GAC, pg. 12-13. *See infra* Sections VI.C. & VI.D. for further discussion of these issues. (LON00800508-41)

(3) Following the completion of MFR1, Shell announced on March 18, 2004 a further recategorization of 250 million boe of reserves previously reported as proved as of December 31, 2002, and a reduction of approximately 220 million boe in the volume of proved reserves it had initially announced it would report for year-end 2003.

(a) Shell press release dated March 18, 2004, pg. 1.

(i) "A number of issues have been identified to date, leading to the recategorisation of a further 250 million barrels of oil equivalent ('boe') as at the end of 2002. In addition Shell has reduced the volume of proved reserves it planned to book in 2003 by approximately 220 million boe of proved reserves (including volumes from Ormen Lange)." (MISC00012718-22)

b) Major Field Review #2 ("MFR2")

(1) MFR2 began in late March 2004, after the conclusion of the putative Class Period (April 8, 1999 to March 18, 2004). This review lasted approximately three weeks and reviewed some 280 fields (including those reviewed in MFR1), resulting in a total coverage of some 90% of proved reserves, including those reviewed in MFR1. EP Reserves Review – Second Report, dated April 8, 2004, pg. 2. (Doc. ID#600000000004925)

(2) Teams of three individuals each, consisting of an independent petroleum engineering consultant from Ryder Scott Company, a representative of Shell's external auditors, and a senior Shell staff member, visited various operating units to carry out the reviews of the same areas upon which MFR1 had focused its reviews, *see supra* Section VI.B.2.a)(2). EP Reserves Review – Second Report, dated April 8, 2004, pg. 4-5. (Doc. ID#600000000004925)

(3) Shell announced the results of MFR2 on April 19, 2004, after the end of the Class Period.

(a) Shell press release dated April 19, 2004, pg. 2-3.

(i) "Shell intends to restate a total of approximately 4.35 billion boe as per end 2002. . . . As a result of the exercise just completed, in addition to the recategorizations of proved reserves volumes announced on January 9, 2004, and March 18, 2004, a further 0.3 billion boe of proved reserves originally reported as at December 31, 2002, will be recategorized. . . . Additionally, the company will be reducing the amount which it had originally planned to book in 2003 . . . by around 0.5 billion boe."

(ii) "In total, almost 300 fields covering some 90% of the global reserves base have been addressed, including virtually all fields above 10 million barrels and also addressing those fields in associated companies." (MISC0010796-819)

(4) The further recategorizations of proved reserves announced on April 19, 2004 were due to technical considerations, such as the interpretation of seismic and well data and reservoir modeling, as well as to considerations of project maturity.

(a) Shell press release dated April 19, 2004, pg. 3.

(i) "The majority of the recategorisations announced today are related to the application of technical data, where the criteria for reasonable certainty remain a subjective assessment of the available seismic data, well data, reservoir modeling and other technical information. Additionally some remaining issues around project maturity were identified." (MISC0010796-819)

3. On May 24, 2004, also after the end of the Class Period, Shell announced the reduction of 103 million boe of proved reserves for its Canadian subsidiary as a result of the use of an incorrect method to account for royalties paid in cash.

a) Shell press release, "Advice in advance of the publication of the 2003 Annual Reports and Accounts," dated May 24, 2004, pg. 1.

(1) "For the years ended 1999 to 2002, proved reserves and production included royalties paid in cash on certain properties in Canada (consistent with practice for properties outside North America). These have now been removed from proved reserves (consistent with practice for properties in the U.S.), resulting in a reduction at 31 December 2003, relative to earlier announcements, of 103 million barrels of oil equivalent (boe) and a reduction of production of 9 mln boe for the year 2003."

(2) "The aggregate effect of the reserves restatement, including the previously disclosed recategorisations and an adjustment with respect to royalties paid in cash in Canada, brought the total for 2002 to 4.47 billion barrels of oil equivalent." (MISC00012749-52)

C. Reasons Underlying the Reserves Restatements and Reductions

1. In its 2003 Annual Report on Form 20-F, filed on June 30, 2004, Shell listed several areas in which the proved reserves it had previously reported

were at variance with Rule 4-10 or the SEC staff's interpretation thereof. These areas of variance, are more fully described above at Section VI.D.

a) 2003 Annual Report on Form 20-F, Supplemental Information – Oil and Gas (unaudited), pg. G44-G53.

(1) Investment Commitment;

(2) Market Assurance;

(3) Governmental or Regulatory Approval;

(4) Field Performance and Project Delivery;

(5) Year-end Pricing;

(6) Technical Definition, including;

(a) Proved Area – Lateral Extent,

(b) Improved Recovery,

(c) Forecasting Methodology,

(d) Economic Producibility; and,

(7) Royalty Calculations (MISC00040158-398)

2. It is common to refer to assessing whether a hydrocarbon resource has satisfied the criteria in (a) through (d), above, as assessing the resource's "project maturity."

a) Cooper

(1) "The primary reasons for the restatements . . . were (*i*) lack of adequate investment commitment, (*ii*) insufficient assurance of a market for the product, (*iii*) lack of governmental or regulatory approval, (*iv*) failure to properly account for negative field performance or deferment of project delivery . . . ." (Decl. ¶ 24)

(2) "The reserves recategorized for lack of 'project maturity' included those that Shell determined had not met the SEC's 'reasonable certainty' test, as interpreted by the SEC staff, for reasons reflected in items (*i*)-(*iv*), above." (Decl. ¶ 25)

3. Only the operating unit management, in conjunction with the Group Reserves Coordinator (the "GRC") and the GRA in the Netherlands, can

determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

D. Variances Between the SEC Guidance and Shell's Reported Proved Reserves

1. As noted above (*see supra* Section VI.C.1.), Shell's 2003 Annual Report on Form 20-F listed several areas in which Shell's previously reported proved reserves were at variance with Rule 4-10 and the SEC staff's interpretations thereof. Following is a discussion of the provisions of Rule 4-10 or the SEC staff's guidance regarding these issues and the manner in which Shell's previously reported proved reserves varied from the Rule or the staff's guidance.

a) SEC release *Current Accounting and Disclosure Issues* issued on June 30, 2000 (the "Staff Guidance") and 2003 Annual Report on Form 20-F, Supplemental Information – Oil and Gas (unaudited), pg. G44-G53. (MISC00040158-398).

(1) Investment Commitment

(a) The Staff Guidance states in paragraph 4: "A commitment by the company to develop the necessary production, treatment and transportation infrastructure is essential to the attribution of proved undeveloped reserves."

(b) Shell states in the Supplementary Information – Oil and Gas section of its 2003 Annual Report on Form 20-F (the "2003 Supplementary Information"): "Under prior Group [G]uidelines, proved reserves were booked in some cases upon progress with development planning. However, this did not in all cases meet the requirement under Rule 4-10 to demonstrate specific commitment to development actions."

(2) Market Assurance

(a) The Staff Guidance states in paragraph 4: "Economic uncertainties such as the lack of a market (e.g. stranded hydrocarbons) . . . can also prevent reserves from being classified as proved. . . . Issuers must demonstrate that there is reasonable certainty that a market exists for the hydrocarbons . . . ."

(b) Shell states in the 2003 Supplementary Information: "Volumes of hydrocarbons were booked as proved reserves with respect to certain projects for which there was insufficient evidence of future market demand at the date of booking to conclude that there was 'reasonable certainty' that it would be economic to recover those volumes under conditions existing at the date of booking."

(3) Government/Regulatory Approvals

(a) The Staff Guidance provides in paragraph 4: "The history of issuance and continued recognition of permits . . . by regulatory bodies and governments should be considered when determining whether hydrocarbon accumulations can be classified as proved reserves."

(b) Shell states in the 2003 Supplementary Information: "Volumes of hydrocarbons were booked as proved reserves with respect to certain projects for which governmental or regulatory approvals were not sufficiently assured for there to be 'reasonable certainty' of the recovery of those volumes in future years."

(4) Field performance and project delivery

(a) Shell states in the 2003 Supplementary Information: "Volumes of hydrocarbons were booked and maintained as proved reserves with respect to certain development projects in producing fields notwithstanding a deferment in project execution or a decline in actual production volumes and forecasts when these indications should have suggested that there was no longer 'reasonable certainty' that the originally estimated volumes would be recovered in the future."

(5) Year-end pricing

(a) SEC Rule 4-10 states: "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*." 17 C.F.R. § 210.4-10(a)(2) (emphasis added).

(b) Shell states in the 2003 Supplementary Information: "Volume entitlements under Production Sharing Contracts, and other agreements for which reserves are estimated using the 'economic entitlement' method, were determined using the prices that were used internally by the Group for screening investment decisions and for business planning, rather than the year-end price as required under Rule 4-10."

(c) EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

(i) Cooper

"In the years for which proved reserves were restated because of the [year-end pricing] issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the [year-end prices], to estimate their proved reserves." (Decl. ¶ 29)

(6) Technical Definition

(a) Lowest Known Hydrocarbon ("LKH")

(i) The Staff Guidance states in paragraph 2: "The area of reservoir considered proved includes that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, . . . but which can be reasonably judged as *economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.*" (Emphasis added)

(ii) Shell states in the 2003 Supplementary Information: "In some cases, volumes occurring below the [LKH] . . . had been included in proved reserves estimates. Such volumes were considered defensible in prior years generally on the grounds that evidence of the location of fluid contacts was available through measurements of the pressure gradients in the reservoirs concerned."

(iii) No proved reserves were restated due to the LKH issue.

Cooper

> "As a result of subsequent discussions and correspondence between Shell and the SEC staff, Shell determined that the SEC staff's LKH interpretation represented new information that caused Shell to change its previous estimates of certain reserves in 2003. Shell therefore reflected all changes resulting from the SEC's LKH interpretation as a negative 'revision' to its currently reported proved reserves in the Shell 2003 Annual Report on Form 20-F. Shell did not

restate any previously reported reserves based on the SEC's LKH interpretation." (Decl. ¶ 31(a))

(b) Proved Area – Lateral Extent

(i) The Staff Guidance states in paragraph 2: "If there is an indication of economic producibility by either formation test or production, *the reserves in the legal and technically justified drainage area around the well* projected down to a . . . LKH may be considered to be proved." Paragraph 6 states: "The SEC staff emphasizes that proved reserves *cannot be claimed more than one offset location away* from a productive well if there are no other wells in the reservoir, even though seismic data may exist." (Emphasis added)

(ii) Shell states in the 2003 Supplementary Information: "In some cases, volumes occurring in parts of the reservoir that are more than one offset development well location from existing well penetrations had been booked as proved reserves in the absence of sufficient proof of continuous and economically productive reservoir in the areas concerned."

(iii) Shell states in its March 18, 2004 announcement that the principal reason for proved reserves' being restated for "proved area considerations was because the operating unit did not strictly follow SEC guidance in that 3-D seismic data was used to define the 'proved area' (between well control points) without the necessary supporting evidence that the SEC guidance requires." Shell press release dated March 18, 2004, pg. 2. (MISC00012718-22)

(c) Improved recovery

(i) The Staff Guidance states in paragraph 6: "Reserves cannot be classified as proved undeveloped reserves based on improved recovery techniques until such time that they have been proved effective in that reservoir or an analogous reservoir in the same geologic formation in the immediate area. An analogous reservoir is one having at least the same values or better for porosity, permeability, distribution, thickness, continuity and hydrocarbon saturations."

(ii) Shell states in the 2003 Supplementary Information: "In some cases, volumes related to the successful implementation of improved recovery processes had been booked as proved reserves in the absence of sufficient proof, in accordance with SEC guidance, of 'reasonable certainty' that the processes would be effective in the specific reservoirs concerned."

(d) Forecasting Methodology

(i) The Staff Guidance states in paragraph 1: "The determination of reasonable certainty is generated by supporting geological and engineering data. There must be data available which indicate that assumptions such as decline rates, recovery factors, reservoir limits, recovery mechanisms and volumetric estimates, gas-oil ratios or liquid yield are valid."

(ii) Shell states in the 2003 Supplementary Information: "In some cases, volumes booked on the basis of sophisticated computer modeling were not sufficiently supported by actual reservoir performance to satisfy the requirement for 'reasonable certainty' in the estimation of proved reserves."

(iii) Shell also states: "This volume was estimated to be 160 million boe at the end of 2003 and substantially all will be accounted for through the revisions occurring during the year 2003."

(e) Economic Producibility

(i) The Staff Guidance states in paragraph 7: "If the combination of data from open-hole logs and core analyses is overwhelmingly in support of economic producibility and the indicated reservoir properties are analogous to similar reservoirs in the same field that have produced or demonstrated the ability to produce on a conclusive formation test, the reserves may be classified as proved."

(ii) Shell states in the 2003 Supplementary Information: "In some cases, proved reserves may have been assigned to reservoirs in the absence of information from a combination of electrical and other type logs and core analyses sufficient to indicate the reservoirs were analogous to similar reservoirs in the same field which were producing or demonstrated the ability to produce on a formation test."

(iii) Shell also states: "However, there were no material instances of reserves that were restated solely for this reason."

(f) Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions," *i.e.*, LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

(i) Cooper

"Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

(7) Other

(a) An error in accounting for the acquisition of Enterprise Oil Limited in 2002 resulted in a reduction of 5 million boe in two former Enterprise properties located in Brazil. April 20, 2004 e-mail from R. Aalbers to B. Jespers. (RJW01031783-84)

(b) Revised treatment of royalty payments by a Canadian subsidiary resulted in the reduction of 89 million boe. This adjustment was announced after the Class Period and is not a part of the Complaint. *See supra* Section VI.B.3.a)(2).

E. Total Restatements and Reductions

1. Shell restated its proved reserves for the years ending 1997 through 2002.

a) Cooper

(1) "Pursuant to discussions among Shell, the SEC, Shell's external auditors, and legal counsel following the January Recategorization Announcement, Shell's Amended 2002 Annual Report on Form 20-F and its 2003 Annual Report on Form 20-F, filed on July 1, 2004 and June 30, 2004, respectively, restated proved reserves for the years ending December 31, 1997 through December 31, 2002 that Shell had previously reported in its Annual Reports and SEC filings on Form 20-F." (Decl. ¶ 20)

(2) Shell did not restate its proved reserves for the year ending 2003, but rather merely reduced the volume of proved reserves it had previously announced it would report for 2003.

2. The table printed below shows the total proved reserves originally reported, total restatements for each year (or, for 2003, the reduction in the previously announced proved reserves increase), and total proved reserves after the restatement or reduction. Figures are given in billion boe ("bboe"). 2003 Annual Report on Form 20-F, Supplemental Information – Oil and Gas (unaudited), pg. G44-G53. (MISC00040158-398)

		1999	2000	2001	2002	2003
1.	**Reserves as Originally Reported (bboe)**	19.87	19.46	19.10	19.35	
2.	**Restatement/Reduction (bboe)**	(4.58)	(4.85)	(4.53)	(4.47)	(.42)[1]
3.	**Restated/Reduced Reserves (bboe)**	15.29	14.61	14.57	14.88	14.35[2]

F. Country-by-Country Restatements and Reductions

1. The country-by-country and year-by-year restatements for 1999 through 2002 are summarized in the Summary Chart (attached as Appendix A), which shows (*i*) the volumes restated for the particular country or operating unit, (*ii*) the percentages that those volumes represent of the total volumes restated for that year, and (*iii*) the percentages that the volumes represent of the total volume of proved reserves originally reported for that year. For 2003, the Summary Chart shows (*i*) the reductions in proved reserves that Shell had previously announced it would report for 2003, (*ii*) the percentages that those volumes represent of the total reductions for 2003, and (*iii*) the percentages that the volumes represent of the total proved reserves reported for 2003.[3]

2. The following country-by-country tables are based on the restated or reduced proved reserves reflected in the Summary Chart for all countries or operating units that reported a restatement of proved reserves for 1999 through 2002 or a reduction in the previously announced proved reserves for 2003. Other than those listed below, there were no proved reserves restated for 1999 through 2002 or, for 2003, reduced from those originally proposed to be reported in any country or by any operating unit.

3. For 1999 through 2002, Row 1 of the following tables shows the volumes restated in bboe. Row 2 shows the percentage that the volume in Row 1 represents of the total volumes restated for that year, as reflected in the

[1] Shell's 2003 Annual Report on Form 20-F refers to the reduction in the previously announced estimation of 2003 proved reserves as "approximately 400 million boe." The reduction amount reflected in this table for 2003 is based on Doc. ID#600000000004867 as summarized in the Summary Chart, see *supra* Section VI(F)(1).

[2] Amount of total proved reserves as reported by Shell in its 2003 Annual Report on Form 20-F.

[3] The country-by-country restatement or reduction amounts are summarized from Proved Reserves Booking Lookback. (Doc. ID#600000000004867) The total reserves reported by Shell are those stated in Supplementary Information – Oil and Gas (unaudited) section of Shell's 2003 Annual Report on Form 20-F. (MISC00040158-398).

Summary Chart. Row 3 shows the percentage that the volume in Row 1 represents of the total volume of proved reserves that were originally reported for that year, as reflected in the Summary Chart.

4. For 2003, Row 1 of the following tables shows the reductions in proved reserves that Shell had previously announced it would report for 2003; Row 2 shows the percentage that the reduction in Row 1 represents of the total reductions for 2003, and Row 3 shows the percentage that the reduction in Row 1 represents of the total proved reserves reported for 2003.

Abu Dhabi

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.00	0.00	0.00	0.05
2.	**% of Total Restatement/Reduction**	0.00%	0.00%	0.00%	0.00%	11.03%
3.	**% of Originally Reported Reserves**	0.00%	0.00%	0.00%	0.00%	0.32%

5. The reduction in proved reserves for Abu Dhabi in 2003 resulted primarily from OPEC quota adjustments. (*See* Cooper Decl. ¶ 39)

6. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Abu Dhabi.

Angola

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.08	0.08	0.02	0.00
2.	**% of Total Restatement/Reduction**	0.00%	1.55%	1.66%	0.47%	0.00%
3.	**% of Originally Reported Reserves**	0.00%	0.39%	0.39%	0.11%	0.00%

7. The proved-reserves reductions for Angola in 2000 and 2001 resulted primarily from the lack of "project maturity." Proved Reserves Booking Lookback (Doc. ID#600000000004867).

8. The proved-reserves reduction for Angola in 2002 resulted primarily from an incorrect estimation of the "proved area."

a) Cooper

(1) "The reduction in proved reserves for Angola in 2002 was primarily the result of an incorrect estimation of the proved area." (Decl. ¶ 40)

9. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

10. Only operating units, and the GRC and GRA based in the Netherlands, could make determinations regarding compliance with "technical definitions," for example, LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

11. Shell Deepwater Services ("SDS") did not determine or report proved reserves in Angola.

a) Inglis

(1) "SDAN [*i.e.*, Shell Development Angola] was ultimately responsible for its reserves estimates and made all the final decisions regarding its ARPR submissions. As such, SDS did not determine the quantity of 'proved' reserves that were submitted to EP headquarters . . . ." (Decl. ¶ 11)

b) Leonard

(1) "During my employment at SDS, SDAN was solely responsible for estimating and reporting its proved reserves and for submitting its ARPR to the Group Reserves Coordinator . . . ." (Decl. ¶ 19)

12. Nor is there any evidence that any other U.S.-based entity or personnel estimated or reported proved reserves for Angola.

13. For further discussion of the services SDS provided to SDAN *see infra* Section VII.E.

Australia

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	1.14	1.05	1.00	0.75	0.01
2.	**% of Total Restatement/Reduction**	24.87%	21.62%	22.01%	16.67%	2.88%
3.	**% of Originally Reported Reserves**	5.73%	5.39%	5.22%	3.86%	0.08%

14. Shell Development Australia ("SDA") reported proved reserves for properties it owned directly and indirectly through its equity interest in Woodside Petroleum Ltd. ("Woodside").

a) Cooper

(1) "Shell reports proved reserves for Australian petroleum interests that it owns directly; it also reports its share of proved reserves in petroleum interests owned by [Woodside], in which Shell owns a minority equity interest. In many cases, Shell and Woodside own interests in the same petroleum properties. The table above refers to the proved reserves reported for Australian interests that Shell owned both directly and indirectly." (Decl. ¶ 41)

15. The majority of SDA's proved-reserves reductions were due to the lack of "project maturity" of the Gorgon Field project and other gas projects.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reductions in proved reserves for Australia in 2002 and 2003 were primarily the result of lack of technical and/or commercial maturity or a number of gas field developments." (Decl. ¶ 42)

16. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

17. No U.S.-based entity or personnel estimated or reported proved reserves for SDA.

a) S. Bell

(1) "During the entirety of my employment by SDA through March 18, 2004, no United States-based entity or personnel assisted SDA or me in estimating of SDA's proved reserves or other oil and gas resources." (Decl. ¶ 9)

18. Neither SDS nor SEPTAR estimated or reported proved reserves for SDA.

a) S. Bell

(1) "To my knowledge, no work was performed for SDA during my period of employment by [SDS], whether relating to the Gorgon field or otherwise." (Decl. ¶ 10)

Bangladesh

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.01	0.02	0.02	0.02	0.00
2.	**% of Total Restatement/Reduction**	0.26%	0.35%	0.40%	0.34%	0.00%
3.	**% of Originally Reported Reserves**	0.06%	0.09%	0.09%	0.08%	0.00%

19. The reductions in proved reserves for Bangladesh were the result of use of incorrect year-end prices ("YEP").

a) Proved Reserves Booking Lookback. (Doc. ID#600000000004867)

b) Cooper

(1) "The reduction in proved reserves for Bangladesh in 2002 was primarily the result of the prior use of incorrect product

prices to estimate the volumes rather than YEP." (Decl. ¶ 43)

20. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the [year-end pricing] issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the [year-end prices], to estimate their proved reserves." (Decl. ¶ 29)

21. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Bangladesh.

<u>Brazil</u>

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.00	0.00	0.02	0.003
2.	**% of Total Restatement/Reduction**	0.00%	0.00%	0.00%	0.34%	0.72%
3.	**% of Originally Reported Reserves**	0.00%	0.00%	0.00%	0.08%	0.02%

22. The proved reserves reductions in Brazil were due to the use of incorrect recovery factors and analogues for improved recovery processes.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reductions in proved reserves for Brazil in 2002 and 2003 were primarily due to the lack of reasonable certainty of the application of a recovery factor for an improved recovery process and an incorrect recovery factor forecasting methodology." (Decl. ¶ 44)

23. Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions" such as LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

24. SDS did not provide technical services to the Brazil operating unit that restated proved reserves.

a) Bichsel

(1) "When I was in [SDS] the services that we provided [were] around exploration. We did not have any reserves found at that stage. We were exploring. When I was there we had some exploration successes that led to the discovery of scope for recovery volumes, but not to any reserves in the sense of proved reserves or expectation reserves." (Dep. pg. 131:11-20)

25. Nor is there any evidence that any other U.S.-based entity or personnel estimated or reported proved reserves for Brazil.

Brunei

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.40	0.41	0.43	0.38	0.00
2.	**% of Total Restatement/Reduction**	8.65%	8.42%	9.47%	8.42%	0.00%
3.	**% of Originally Reported Reserves**	1.99%	2.10%	2.25%	1.95%	0.00%

26. The majority of reductions in proved reserves in Brunei resulted from a lack of "project maturity."

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Brunei in 2002 was primarily the result of lack of project definition and maturity." (Decl. ¶ 45)

27. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

28. No U.S.-based entity or personnel compiled or reported proved reserves for Brunei Shell Petroleum ("BSP").

a) Kennett

(1) "No entity based in the United States and no United States-based personnel played any role in compiling BSP's ARPR, and the ARPR was never submitted to or from the United States." (Decl. ¶ 21)

b) For a further discussion of the services SDS provided to BSP, *see infra* Sections VII.F.4.

<u>Canada</u>

		1999	**2000**	**2001**	**2002**	**2003**
1.	**Restatement/Reduction (bboe)**	0.11	0.12	0.10	0.09	0.01
2.	**% of Total Restatement/Reduction**	2.34%	2.41%	2.14%	1.99%	3.36%
3.	**% of Originally Reported Reserves**	0.54%	0.60%	0.51%	0.46%	0.10%

29. Until April 2007, Shell Canada Limited ("Shell Canada") was a publicly traded company whose shares were listed and traded on the Toronto Stock Exchange. Shell owned a majority equity interest in Shell Canada and reported its share of Shell Canada's proved reserves in Shell's SEC filings. (*See* Cooper Decl. ¶ 46)

30. The reductions in proved reserves reported by Shell Canada were due to the incorrect treatment of royalty payments.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reductions in proved reserves for Canada in 2002 and 2003 resulted primarily from incorrect treatment of royalties paid in cash on production from Shell Canada's properties." (Decl. ¶ 47)

31. Shell did not announce the restatements (or reductions for 2003) for Shell Canada until May 24, 2004, after the Class Period had ended. (*See* Cooper Decl. ¶ 48)

32. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Shell Canada.

<u>China</u>

		1999	**2000**	**2001**	**2002**	**2003**
1.	**Restatement/Reduction (bboe)**	0.00	0.001	0.00	0.001	0.00
2.	**% of Total Restatement/Reduction**	0.00%	0.02%	0.00%	0.02%	0.00%
3.	**% of Originally Reported Reserves**	0.00%	0.01%	0.00%	0.01%	0.00%

33. The reduction in proved reserves for China resulted from use of incorrect year-end prices.

a) Proved Reserves Booking Lookback. (Doc. ID#600000000004867)

b) Cooper

(1) "The reduction in proved reserves for China in 2002 was primarily the result of the prior use of incorrect product prices to estimate the volumes rather than YEP." (Decl. ¶ 49)

34. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the YEP issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the YEP, to estimate their proved reserves." (Decl. ¶ 29)

35. SDS did not assist Shell China with the estimation of proved reserves.

a) Sears

(1) "Q. Do you recall whether [SDS] was asked to calculate volumes of hydrocarbons for purposes of proved reserve reporting in China? A. I do not believe that we were." (Dep. pg. 83:18-21)

36. Nor is there any evidence that any other U.S.-based entity or personnel estimated or reported proved reserves for China.

Egypt

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.05	0.03	0.01	0.02	0.00
2.	**% of Total Restatement/Reduction**	1.07%	0.56%	0.31%	0.38%	0.00%
3.	**% of Originally Reported Reserves**	0.25%	0.14%	0.07%	0.09%	0.00%

37. The reductions in proved reserves reported for Egypt resulted from use of incorrect year-end prices.

a) Proved Reserves Booking Lookback. (Doc. ID#600000000004867)

b) Cooper

(1) "The reduction in proved reserves for Egypt in 2002 was primarily the result of the prior use of incorrect product prices to estimate the volumes rather than YEP." (Decl. ¶ 51)

38. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the YEP issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the YEP, to estimate their proved reserves." (Decl. ¶ 29)

39. SDS did not advise Shell Egypt with respect to the categorization of proved reserves.

a) Bichsel

(1) "SDS never provided any technical assistance or advice to Shell Egypt with respect to the categorization of proved reserves." (Decl. ¶ 14)

40. Nor is there any evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Egypt.

Gabon

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.001	0.002	0.001	0.001	0.00
2.	**% of Total Restatement/Reduction**	0.02%	0.04%	0.02%	0.02%	0.00%
3.	**% of Originally Reported Reserves**	0.01%	0.01%	0.01%	0.01%	0.00%

41. The reductions in proved reserves reported for Gabon resulted from use of incorrect year-end prices.

a) Proved Reserves Booking Lookback. (Doc. ID#600000000004867)

b) Cooper

(1) "The reduction in proved reserves for Gabon in 2002 was primarily the result of the prior use of incorrect product prices to estimate the volumes rather than YEP." (Decl. ¶ 52)

42. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the YEP issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the YEP, to estimate their proved reserves." (Decl. ¶ 29)

43. SDS did not advise Shell Gabon with respect to the categorization of proved reserves.

a) Bichsel

(1) "SDS never provided any technical assistance or advice to Shell Gabon with respect to the categorization of proved reserves." (Decl. ¶ 32)

44. Nor is there any evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Gabon.

Germany

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.004	0.01	0.01	0.00
2.	**% of Total Restatement/Reduction**	0.00%	0.08%	0.24%	0.29%	0.00%
3.	**% of Originally Reported Reserves**	0.00%	0.02%	0.06%	0.07%	0.00%

45. The reductions in proved reserves reported for Germany resulted from the incorrect estimation of proved area and incorrect application of recovery factors.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Germany in 2002 was primarily the result of the incorrect estimation of proved area and incorrect application of recovery factor forecasting methodologies." (Decl. ¶ 53)

46. Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions" such as LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the

Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

47. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Germany.

Iran

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.06	0.09	0.07	0.05	0.00
2.	**% of Total Restatement/Reduction**	1.38%	1.86%	1.55%	1.07%	0.00%
3.	**% of Originally Reported Reserves**	0.32%	0.46%	0.37%	0.25%	0.00%

48. The reductions in proved reserves reported for Iran resulted from use of incorrect year-end prices.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Iran in 2002 was primarily the result of the prior use of incorrect product prices to estimate the volumes rather than YEP." (Decl. ¶ 54)

49. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the YEP issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the YEP, to estimate their proved reserves." (Decl. ¶ 29)

50. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Iran.

Ireland

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.00	0.00	0.05	0.00
2.	**% of Total Restatement/Reduction**	0.00%	0.00%	0.00%	1.05%	0.00%
3.	**% of Originally Reported Reserves**	0.00%	0.00%	0.00%	0.24%	0.00%

51. The reduction in proved reserves for Ireland in 2002 resulted from a lack of "project maturity" due to a lack of assurance of receiving necessary governmental or regulatory approvals.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Ireland in 2002 was primarily due to lack of project maturity and the absence of governmental approvals." (Decl. ¶ 55)

52. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" – including the reasonable assurance that the necessary governmental or regulatory approvals would be received – to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

53. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Ireland.

Italy

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.00	0.00	0.03	0.00
2.	**% of Total Restatement/Reduction**	0.00%	0.00%	0.00%	0.56%	0.00%
3.	**% of Originally Reported Reserves**	0.00%	0.00%	0.00%	0.13%	0.00%

54. The reduction in proved reserves for Italy in 2002 resulted from a lack of "project maturity."

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Italy in 2002 was primarily due to lack of project maturity." (Decl. ¶ 56)

55. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

56. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Italy.

Kazakhstan

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.00	0.00	0.38	0.00
2.	**% of Total Restatement/Reduction**	0.00%	0.00%	0.00%	8.49%	0.00%
3.	**% of Originally Reported Reserves**	0.00%	0.00%	0.00%	1.96%	0.00%

57. The restatement of proved reserves for Kazakhstan in 2002 resulted from a lack of "project maturity."

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Kazakhstan in 2002 was primarily due to lack of project maturity." (Decl. ¶ 57)

58. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

59. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Kazakhstan.

<u>Malaysia</u>

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.07	0.13	0.10	0.12	0.04
2.	**% of Total Restatement/Reduction**	1.57%	2.62%	2.25%	2.68%	9.35%
3.	**% of Originally Reported Reserves**	0.36%	0.65%	0.53%	0.62%	0.27%

60. The reductions in proved reserves reported for Malaysia primarily resulted from use of incorrect year-end prices, incorrect estimation of proved area and incorrect application of recovery factor methodologies.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reductions in proved reserves for Malaysia in 2002 and 2003 were primarily the result of prior use of incorrect product prices to estimate the volumes rather than YEP, incorrect estimation of proved area and incorrect application of recovery factor forecasting methodologies." (Decl. ¶ 58)

61. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the [year-end pricing] issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the [year-end prices], to estimate their proved reserves." (Decl. ¶ 29)

62. Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions" such as LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

63. SDS did not advise Shell Malaysia with respect to proved reserves.

a) Bichsel

(1) "SDS never provided any technical assistance or advice to Shell Malaysia with respect to the categorization of proved reserves." (Decl. ¶ 15)

64. Nor is there any evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Malaysia.

The Netherlands

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.04	0.04	0.04	0.04	+0.06
2.	**% of Total Restatement/Reduction**	0.85%	0.80%	0.88%	0.89%	+14.39%
3.	**% of Originally Reported Reserves**	0.20%	0.20%	0.21%	0.21%	+0.42%

65. For 2003, Shell increased the proved reserves it had proposed to report for the Netherlands by 0.06 bboe. (*See* Cooper Decl. ¶ 60)

66. The restated proved reserves for the Netherlands for the years 1999 through 2002 resulted from a lack of "project maturity."

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for the Netherlands in 2002 was primarily due to lack of project maturity." (Decl. ¶ 59)

c) Comment Letter dated Jan. 23, 2004, pg. 4 (V0020008-38):

(1) "Following exploration drilling . . . a moratorium on drilling in the Waddenzee was imposed by the Dutch government in 1999."

67. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" – including the reasonable assurance that the necessary governmental or regulatory approvals would be received – to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

68. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for the Netherlands.

New Zealand

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.03	0.07	0.04	0.02
2.	**% of Total Restatement/Reduction**	0.00%	0.56%	1.57%	0.80%	3.60%
3.	**% of Originally Reported Reserves**	0.00%	0.14%	0.37%	0.19%	0.10%

69. The majority of reductions in proved reserves in New Zealand resulted from a lack of "project maturity" and incorrect application of recovery factor forecasting methodologies."

a) Proved Reserves Booking Lookback. (Doc. ID#600000000004867)

b) Cooper

(1) "The reduction in proved reserves for New Zealand in 2002 was primarily due to lack of project maturity. The reduction in proved reserves for New Zealand in 2003 was primarily due to incorrect application of recovery factor forecasting methodologies." (Decl. ¶ 61)

70. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

71. Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions" such as LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

72. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for New Zealand.

Nigeria (SNEPCO)

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.24	0.36	0.33	0.11	+0.01
2.	**% of Total Restatement/Reduction**	5.22%	7.45%	7.31%	2.44%	+1.92%
3.	**% of Originally Reported Reserves**	1.20%	1.86%	1.73%	0.56%	+0.06%

73. For 2003, Shell increased by 0.01 bboe the proved reserves it had proposed to report for SNEPCO. (*See* Cooper Decl. ¶63)

74. The majority of reductions in proved reserves in SNEPCO for the years 1999 through 2002 resulted from a lack of "project maturity."

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for SNEPCO in 2002 was primarily due to lack of project maturity." (Decl. ¶62)

75. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group

Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

76. SDS did not estimate or report proved reserves for SNEPCO.

a) McFadden

(1) "SDS was not responsible for estimating, and did not estimate, proved reserves for SNEPCO. Furthermore, SDS was not responsible for reporting, and did not report, SNEPCO's proved reserves to E&P headquarters in The Hague." (Decl. ¶ 13)

b) For a further discussion of the services SDS provided to SNEPCO, *see infra* Section VII.D.

77. Nor is there any evidence that any other U.S.-based entity or personnel estimated or reported proved reserves for SNEPCO.

<u>Nigeria (SPDC)</u>

		1999	**2000**	**2001**	**2002**	**2003**
1.	**Restatement/Reduction (bboe)**	1.83	1.62	1.59	1.50	0.04
2.	**% of Total Restatement/Reduction**	39.91%	33.51%	35.17%	33.43%	10.55%
3.	**% of Originally Reported Reserves**	9.20%	8.35%	8.34%	7.73%	0.31%

78. The majority of reductions in proved reserves for SPDC resulted from a lack of "project maturity" for many of its properties.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) The reductions in proved reserves for SPDC in 2002 and 2003 were primarily due to lack of project maturity. (Decl. ¶ 64)

79. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

80. The Houston-based staff of Shell Exploration and Production Technology, Applications and Research ("SEPTAR") did not do any work for SPDC.

a) Percival

(1) "The SEPTAR staff [who performed services for SPDC] were all based in Rijswijk." (Decl. ¶ 21)

81. SEPTAR services were provided to SPDC exclusively by the Rijswijk office.

a) Okon

(1) "[L]imited technical services . . . [to SPDC] were provided exclusively by the SEPTAR team referred to as AGI, which was based in Rijswijk." (Decl. ¶ 6)

b) For a further discussion of the services SEPTAR provided to SPDC, *see infra* Section VIII.N.

82. Nor did any other U.S.-based entity or personnel compile or report proved reserves for SPDC.

a) Hoppe

(1) "No part of SPDC's ARPR was compiled in or submitted from the United States or by United States-based personnel." (Decl. ¶ 14)

Norway

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.10	0.13	0.14	0.14	0.19
2.	**% of Total Restatement/Reduction**	2.23%	2.72%	3.09%	3.13%	45.32%
3.	**% of Originally Reported Reserves**	0.51%	0.68%	0.73%	0.72%	1.32%

83. The reductions in proved reserves reported for Norway resulted primarily from a lack of "project maturity" and incorrect application of "proved area" criteria.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Norway in 2002 was primarily due to lack of project maturity. The reduction in proved reserves for Norway in 2003 was primarily due to incorrect estimation of proved area." (Decl. ¶ 65)

84. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

85. Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions" such as LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had

satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

86. SDS did not advise Norske Shell, the Shell operating unit in Norway, with respect to proved reserves.

a) Bichsel

(1) "SDS never provided any technical assistance or advice to Norske Shell with respect to the categorization of proved reserves." (Decl. ¶ 31)

87. Nor is there any evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Norway.

<u>Oman (Gisco)</u>

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.31	0.18	0.05	0.10	0.01
2.	**% of Total Restatement/Reduction**	6.72%	3.69%	1.17%	2.12%	1.20%
3.	**% of Originally Reported Reserves**	1.55%	0.92%	0.28%	0.49%	0.03%

88. The reductions in proved reserves reported for Gisco resulted from use of incorrect price assumptions.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reductions in proved reserves for Gisco in 2002 and 2003 were primarily the result of the prior use of incorrect product price assumptions for estimating proved reserves volumes." (Decl. ¶ 66)

89. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the YEP issue, EP management and the GRC in

the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the YEP, to estimate their proved reserves." (Decl. ¶ 29)

90. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Gisco.

Oman (PDO)

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.12	0.46	0.44	0.40	0.02
2.	**% of Total Restatement/Reduction**	2.66%	9.45%	9.69%	8.96%	3.60%
3.	**% of Originally Reported Reserves**	0.61%	2.35%	2.30%	2.07%	0.10%

91. PDO's proved reserves were reduced for a number of reasons, including incorrect application of recovery factors, incorrect estimation of "proved area," and lack of "project maturity."

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for PDO in 2002 was primarily the result of lack of project definition and maturity. The reduction in proved reserves for PDO in 2003 was primarily the result of the incorrect application of recovery factor forecasting methodologies and incorrect estimation of proved area." (Dec. ¶ 67)

92. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

93. Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions" such as LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

94. SDS did not advise PDO with respect to proved reserves.

a) Bichsel

(1) "SDS never provided any technical assistance or advice to [PDO] with respect to the categorization of proved reserves." (Decl. ¶ 33)

95. SEPTAR did not estimate or report proved reserves for PDO.

a) Henderson

(1) "AGH performed certain technical services in . . . Oman . . . [that] did not involve the estimation or reporting of proved reserves." (Decl. ¶ 19)

b) For a further discussion of the services SEPTAR provided to PDO, *see infra* Sections VIII.I. & VIII.J.

96. Nor is there any evidence that any U.S.-based entity or personnel estimated or reported proved reserves for PDO.

The Philippines

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.003	0.01	0.01	0.01	0.01
2.	**% of Total Restatement/Reduction**	0.07%	0.23%	0.18%	0.27%	1.20%
3.	**% of Originally Reported Reserves**	0.02%	0.06%	0.04%	0.06%	0.03%

97. The reductions in proved reserves reported for the Philippines resulted from use of incorrect year-end prices.

a) Proved Reserves Booking Lookback. (Doc. ID#600000000004867)

b) Cooper

(1) "The reductions in proved reserves for the Philippines in 2002 and 2003 were primarily the result of the prior use of incorrect product prices to estimate the volumes rather than YEP." (Decl. ¶ 68)

98. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the YEP issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the YEP, to estimate their proved reserves." (Decl. ¶ 29)

99. SDS did not advise Shell Philippines with respect to proved reserves.

a) Bichsel

(1) "SDS never provided any technical assistance or advice to Shell Philippines with respect to the categorization of proved reserves." (Decl. ¶ 35)

100. Nor is there any evidence that any U.S.-based entity or personnel estimated or reported proved reserves for the Philippines.

<u>Russia (Sakhalin) ("Sakhalin")</u>

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	+0.01	+0.04	+0.02	0.00
2.	**% of Total Restatement/Reduction**	0.00%	+0.10%	+0.93%	+0.51%	0.00%
3.	**% of Originally Reported Reserves**	0.00%	+0.03%	+0.22%	+0.12%	0.00%

101. For 2000, 2001 and 2002, Shell increased Sakhalin's proved reserves. (*See* Cooper Decl. ¶ 69)

102. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Sakhalin.

Syria

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.03	0.03	0.01	0.02	0.01
2.	**% of Total Restatement/Reduction**	0.66%	0.52%	0.20%	0.49%	1.68%
3.	**% of Originally Reported Reserves**	0.15%	0.13%	0.05%	0.11%	0.05%

103. The reductions in proved reserves reported for Syria resulted from use of incorrect year-end prices and incorrect application of recovery factors.

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Syria in 2002 was primarily the result of the prior use of incorrect product prices to estimate the volumes rather than YEP. The reduction in proved reserves for Syria in 2003 was primarily the result of the incorrect application of recovery factor forecasting methodologies." (Decl. ¶ 70)

104. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the YEP issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the YEP, to estimate their proved reserves." (Decl. ¶ 29)

105. Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions" such as LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

106. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for Syria.

United Kingdom

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.03	0.03	0.04	0.15	0.08
2.	**% of Total Restatement/Reduction**	0.70%	0.66%	0.93%	3.4%	20.14%
3.	**% of Originally Reported Reserves**	0.16%	0.16%	0.22%	0.79%	0.59%

107. The reductions in proved reserves reported for the United Kingdom were due to a variety of reasons, but primarily resulted from incorrect application of recovery factors, and incorrect estimation of "proved area."

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reductions in proved reserves reported for the United Kingdom in 2002 and 2003 were primarily the result of the incorrect application of recovery factor forecasting methodologies, lack of reasonable certainty of the application of recovery factors for improved recovery processes and incorrect estimation of proved area." (Decl. ¶ 71)

108. Only operating units, and the GRC and GRA located in the Netherlands, could make determinations regarding compliance with "technical definitions" such as LKH, proved area – lateral extent, improved recovery, forecasting methodology and economic producibility.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had

satisfied the 'technical definition' requirements of Rule 4-10 and the SEC staff's interpretation of the Rule to qualify as proved reserves. The Group Reserves Coordinator, the Group Reserves Auditor and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 32)

109. There is no evidence that any U.S.-based entity or personnel estimated or reported proved reserves for the United Kingdom.

United States

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.00	0.00	0.00	0.00	0.01
2.	**% of Total Restatement/Reduction**	0.00%	0.00%	0.00%	0.00%	1.68%
3.	**% of Originally Reported Reserves**	0.00%	0.00%	0.00%	0.00%	0.05%

110. The reduction in proved reserves Shell had proposed to report for the United States for 2003 resulted from incorrect application of recovery factors and incorrect estimation of "proved area."

a) Proved Reserves Booking Lookback. (Doc. ID#600000000004867)

b) Cooper

(1) "The reduction in proved reserves for the United States in 2003 was primarily the result of lack of reasonable certainty of the application of recovery factors for improved recovery processes, the incorrect application of recovery factor forecasting methodologies and the incorrect estimation of proved area." (Decl. ¶ 72)

111. Shell did not restate any United States proved reserves for 1999, 2000, 2001, or 2002. (*See* Cooper Decl. ¶ 73)

Venezuela

		1999	2000	2001	2002	2003
1.	**Restatement/Reduction (bboe)**	0.04	0.05	0.03	0.08	0.00
2.	**% of Total Restatement/Reduction**	0.83%	0.99%	0.71%	1.79%	0.00%
3.	**% of Originally Reported Reserves**	0.19%	0.25%	0.17%	0.41%	0.00%

112. The reductions in proved reserves reported in Venezuela resulted from use of incorrect year-end prices and a lack of "project maturity."

a) Proved Reserves Booking Lookback (Doc. ID#600000000004867).

b) Cooper

(1) "The reduction in proved reserves for Venezuela in 2002 was primarily the result of lack of project maturity and the prior use of incorrect product prices to estimate volumes rather than YEP." (Decl. ¶74)

113. Only the operating unit management, in conjunction with the GRC and GRA based in the Netherlands, can determine whether resources have achieved sufficient "project maturity" to qualify as proved reserves.

a) Cooper

(1) "Management of the individual operating units, in conjunction with the Group Reserves Coordinator and the Group Reserves Auditor, determined whether reserves had achieved a sufficient state of 'project maturity' to qualify as proved reserves for SEC reporting purposes. The Group Reserves Coordinator, Group Reserves Auditor, and EP management were at all relevant times based in the Netherlands." (Decl. ¶ 26)

114. EP management and the GRC in the Netherlands had directed operating units to use the product prices that EP used to screen its investment decisions – rather than year-end prices – to estimate their proved reserves.

a) Cooper

(1) "In the years for which proved reserves were restated because of the YEP issue, EP management and the GRC in the Netherlands required operating units to use the product prices used by EP to screen its investment decisions and for its business planning purposes, rather than the YEP, to estimate their proved reserves." (Decl. ¶ 29)

115. Venezuela did not report any proved reserves attributable to natural gas reserves or any interests in deepwater during 1999 through 2003. (*See* Cooper Decl. ¶ 75)

116. There is no evidence that SEPTAR estimated or reported proved reserves for Venezuela.

a) Henderson

(1) "AGH performed certain technical services in Venezuela...[that] did not involve the estimation or reporting of proved reserves." (Decl. ¶ 19)

b) For a further discussion of the services SEPTAR provided to Shell Venezuela, S.A., *see infra* Section VIII.K.

117. Nor is there any evidence that any other U.S.-based entity or personnel estimated or reported proved reserves for Venezuela.

TAB 7

FACT SUMMARY

VII. SHELL DEEPWATER SERVICES

Because plaintiffs have been unable to find any potentially relevant U.S. conduct in Shell's corporate structure, in its process of compiling, reviewing, auditing, and approving proved reserves, or on the basis of the proved reserves recategorized, plaintiffs have focused on the activities of two U.S.-based Shell service organizations that provided technical assistance to certain non-U.S. operating units whose own proved reserves were recategorized. This section and the next discuss those two service companies.

Shell Deepwater Services ("SDS") was a service organization formed in 1999 to bring together the technical deepwater expertise previously existing in Shell International Deepwater Services (located in Rijswijk, the Netherlands) and Shell Deepwater Development Services (located in Houston, Texas). Before the merger occurred in 1999, the Rijswijk unit had been performing technical services for operating units located outside the United States, and the Houston unit had been performing services solely for Shell's U.S. EP operating unit, Shell Exploration and Production Company ("SEPCo"). After the merger in 1999, the Rijswijk employees who remained with the combined organization moved to Houston, and the Rijswijk office ceased to exist. Some SDS staff members also were located in New Orleans, Louisiana.

SDS's staff included experts in deepwater geology, turbidite geology (a type of deepwater geological formation that can contain a petroleum reservoir), specific deepwater geophysical and seismic interpretation skills, and other expertise in the technical aspects of deepwater exploration, development, and production.

Like its Houston precursor, SDS continued to provide services primarily to SEPCo, which operates important deepwater assets in the Gulf of Mexico. SDS also offered its technical expertise to Shell operating units in other parts of the world. Deepwater exploration and production is a relatively recent phenomenon and poses unique technical challenges that do not arise in onshore or shallow-water exploration and production. Consequently, Shell operating units with deepwater assets sometimes relied on SDS's specialized expertise for the more difficult technical questions, even though those operating units employed their own reservoir engineers, petrophysicists, and other scientists.

SDS consisted of four units: a well-delivery unit, a finance unit, a project-execution unit, and an Evaluation and Development Planning unit ("EDP").[46] Plaintiffs have focused on EDP's activities in their allegations related to Shell's U.S.-based conduct.[47]

SDS used a service contract referred to as the Cost, Time, and Resources ("CTR") document when forming an agreement with a customer such as a Shell operating unit. The CTR detailed the nature and scope of the technical services that SDS would provide.[48] Those services depended on the operating unit's specific needs: they typically related to pre-exploration evaluation but also could include post-exploration work, such as providing a technical evaluation to support a possible bid to buy acreage.[49]

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46 Knight Dep. at 45:16-20.

47 Richard Sears was head of EDP during the Class Period. He reported to Matthias Bichsel, SDS's Director, and then to Mr. Bichsel's successor, Mark Leonard. All of those men were deposed on September 27, 2006, October 31, 2006 and February 7, 2007, respectively. In 2003, Shell reorganized its technical-services entities, and the work performed by EDP was absorbed into two new entities, EP Projects and EP Solutions.

48 Bichsel Decl. ¶ 7.

49 Knight Dep. at 24:5-10.

SDS's compensation depended on the amount specified in the annual CTR, which was signed before the work began.[50] The operating unit's reported proved reserves were not a metric on SDS's compensation "scorecard."[51]

SDS did not act as an operating unit and was not responsible for investment decisions, business planning, strategy, or contacts with local governments.[52] Nor did SDS take over any operating unit's obligation to estimate and report its own proved reserves in its ARPR submission to the Group Reserves Coordinator in the Netherlands.[53]

For two of SDS's customers – Shell Nigeria Exploration and Production Company ("SNEPCO") (Shell's Nigerian deepwater operating unit) and Shell Development Angola ("SDAN") – members of SDS's EDP unit provided more comprehensive technical support. Plaintiffs have focused on SDS's work for SNEPCO and SDAN, so the following sections will discuss the technical services that SDS provided to those two operating units.

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50 Kluesner Dep. at 83:15-20; Newberry Dep. at 170:10-16; Varley Dep. at 144:12-18; Bichsel Dep. at 156:5-20.

51 Knight Dep. at 144:12-15, 145:17-22; Varley Dep. at 139:13-140:19.

52 *See* May 1999 Briefing Note: EP Leadership Forum Global Deepwater Services, at 3 ("Shell Deepwater Services' role is to provide technical services in support of the approved strategic direction. Similarly, Shell Deepwater Services is not involved in other processes normally associated with asset ownership, except as requested to fulfill a technical supporting role. The asset owner will maintain responsibility for strategy, business planning, investment decisions, business representation, and local and partner contacts and issues. The governance structure for OUs [*i.e.*, operating units] and NVOs [*i.e.*, new venture organizations] will remain unchanged.").

53 Bichsel Dep. at 155:2-6 ("SDS provided the service that did not include the review of ARPRs. The ARPR data, the submission of ARPR data, the reporting of ARPR data is done via the operating units."); Hines Dep. at 122:25-123:7 ("Shell Deepwater Services . . . is a technical service provider, has no jurisdiction over governance, strategy or submissions of ARPRs, Reserves Statements. . . . [R]esponsibility for that is vested in the Asset Teams, so our responsibility was to do technical work to support their ambitions.").

A. **Shell Nigeria Exploration and Production Company ("SNEPCO")**

SNEPCO is, and was during the Class Period, the operating unit responsible for Shell's deepwater assets off the coast of Nigeria. Those deepwater assets include the Bonga Main field, the Bonga Southwest field, the Erha field, and the Abo field.[54]

SNEPCO maintained offices both in Lagos, Nigeria, and in Rijswijk, the Netherlands. Its staff included a Managing Director, a Finance Manager, a Planning and Economics department, a Petroleum Engineering Manager, a Head of Petroleum Engineering, project managers, development managers, reservoir engineers, and other technical experts. None of these employees worked in the United States. The Head of Petroleum Engineering during the Class Period was Sean McFadden, who was based in Nigeria.[55]

1. **SDS's Technical Services for SNEPCO**

SDS provided SNEPCO with technical services throughout the Class Period. Because those services required so many hours of work, SDS established small teams of technical experts within its EDP unit to focus exclusively on SNEPCO's needs. Christopher Varley led the Bonga team, which had originated in the Rijswijk unit of SDS's precursor but moved to Houston in 1999 when SDS was created. The Bonga team provided services initially only for the Bonga Main field and then later for the Bonga Southwest field as well.[56] Patrick McVeigh led the team that provided technical services for the Abo and Erha fields.[57]

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54 SNEPCO is wholly distinct from Shell Petroleum Development Company, the operating unit responsible for Shell's onshore and shallow-water – rather than its deepwater – petroleum resources in Nigeria.

55 Mr. McFadden was deposed on September 7, 2006, and has submitted a declaration.

56 Christopher Varley was deposed on September 15, 2006, and has submitted a declaration.

57 Patrick McVeigh was deposed on December 7, 2006.

The technical assistance that SDS provided to SNEPCO included services such as interpreting seismic data to evaluate the geological properties of reservoirs, building reservoir models, creating proposals, and preparing feasibility studies for drilling development wells.[58]

2. **SDS's Work in Connection with SNEPCO's Hydrocarbon Reserves**

In addition to obtaining the above technical assistance from SDS, SNEPCO also asked SDS to perform certain volumetric estimates. SDS estimated total petroleum resource volumes and certain other classification volumes (such as scope for recovery) in connection with its technical evaluation of SNEPCO's reservoirs. But SDS did *not* estimate SNEPCO's proved reserves when performing its volumetric estimations.[59]

As discussed above, proved reserves depend not only on volumetric estimates but also on economic, business, and commercial considerations. Hydrocarbon volumes cannot be reported as proved reserves under SEC Rule 4-10 unless they are "reasonabl[y] certain[] 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." 17 C.F.R. § 240.4-10. Reasonable certainty of recoverability thus depends on a host of nonvolumetric factors, such as economic conditions, business plans and priorities, capital-allocation decisions, the laws of and agreements with the government of the country in which the operating unit is located, the terms of any joint-venture agreement, and the existence of a market for the hydrocarbons.

SDS did not consider – and did not have the expertise or resources to consider – the full array of nonvolumetric economic, business, and commercial factors necessary to determine whether hydrocarbon resources could be reported as proved reserves. SNEPCO alone

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58 Varley Decl. ¶ 8.

59 Varley Decl. ¶ 25.

was able and required to evaluate all the relevant factors, not just the volumetric estimates generated by SDS, and to estimate and report its own proved reserves based on an informed review of this full set of considerations.[60]

Each year, SNEPCO – like every other Shell operating unit – had to complete its ARPR submission covering its full range of hydrocarbon resources, including proved reserves as well as expectation reserves and scope for recovery resources. SNEPCO's Petroleum Engineering Manager in Nigeria (Osten Olorunsola for year-end 1999 and 2000, and Tunde Ogunnaike for year-end 2001 and 2002) signed SNEPCO's ARPRs for all years of the Class Period.[61] SNEPCO then sent its estimates to the Group Reserves Coordinator in the Netherlands.[62] No U.S.-based employee worked on SNEPCO's ARPR submission.

Mr. McFadden of SNEPCO, as well as Messrs. Varley and McVeigh of SDS, all were familiar with the scope of technical services that SDS provided to SNEPCO, and each of them testified that SDS did not estimate or report SNEPCO's proved reserves.[63]

Moreover, even SNEPCO's own work in Nigeria did not finally determine the operating unit's proved reserves. As discussed above, the Group Reserves Coordinator in the Netherlands, the Group Reserves Auditor in the Netherlands, Shell's external auditors (PwC and KPMG) in England and the Netherlands, and Shell's management in the Netherlands (including the relevant Regional Directorate and the EP Executive Committee) all had to review or approve

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60 Varley Decl. ¶ 12; McFadden Decl. ¶ 13.

61 *See* SNEPCO ARPR submission for year-end 1999 (Doc. #RJW00400629-646); SNEPCO ARPR submission for year-end 2000 (Doc. #RJW00401617-649); SNEPCO ARPR submission for year-end 2001 (Doc. #RJW00070678-706); SNEPCO ARPR submission for year-end 2002 (Doc. #RJW00080376-404).

62 McFadden Decl. ¶ 11; Bichsel Decl. ¶ 10.

63 Varley Decl. ¶ 25; McFadden Decl. ¶ 13; McVeigh Dep. at 109:7-12.

SNEPCO's proposed proved-reserves estimates before those numbers could be included in the total proved reserves that Shell reported to the public from England and the Netherlands and later filed with the SEC.

3. **Irrelevance of SNEPCO's Proved Reserves**

Not only did SDS not estimate or report SNEPCO's proved reserves, but those reserves ultimately are irrelevant to the conduct-test analysis – for several reasons.

First, the majority of SNEPCO's proved reserves at issue in this case were first reported at year-end 1998 or earlier, before SDS came into existence and before the Class Period began in 1999. Any technical services involved in booking those reserves would have been provided by SDS's Rijswijk-based precursor. SNEPCO merely carried forward its previously reported reserves in subsequent years.[64] Thus, Houston-based SDS did not play, and could not possibly have played, any role in SNEPCO's allegedly improper booking of those reserves.

Second, most of the reductions in SNEPCO's proved reserves resulted from SNEPCO's having reported them as proved before reaching a final investment decision about those fields.[65] This project-maturity issue, which involved business-planning and capital-allocation considerations, was entirely unrelated to whatever technical services and volumetric estimates SDS provided to SNEPCO.

Third, SDS's work actually helped to prevent inflation of SNEPCO's proved-reserves estimates. For example, in 2000, SNEPCO was going to book new proved reserves for

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64 *See* Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (Doc. #V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW00082535-49); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW00321825-37); Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW01000022-37); *see also* Barendregt Decl. ¶¶ 19-20.

65 Cooper Decl. ¶ 62; Doc. #600000000004867.

the Erha field and was considering basing its volumetric estimates on recovery-efficiency percentages determined by the field's operator, ExxonMobil. SDS told SNEPCO that ExxonMobil's percentages appeared too high, and SNEPCO ultimately decided to use SDS's lower percentages, which would yield a lower volume of producible hydrocarbons and, thus, lower reported proved reserves.[66]

Fourth, the new proved reserves that SNEPCO added to Shell's total reported proved reserves during SDS's existence (and during the Class Period) amounted to less than 1% of Shell's total reported proved reserves for each of the relevant years. For each of year-end 1999, 2000, and 2001, SNEPCO reported an additional 122 million boe, 122 million boe, and 2.7 million boe, respectively. These additions constituted only 0.61%, 0.63%, and 0.01% of Shell's total reported proved reserves for those years.[67] And at year-end 2002, SNEPCO *decreased*, rather than increased, its proved reserves.[68] In fact, at the end of the Class Period, SNEPCO's reported proved reserves were *lower* than as reported at the beginning of the Class Period. The new proved reserves added during SDS's existence also constituted only a miniscule percentage of the total amount of recategorized reserves: 2.66% in 1999, 2.52% in 2000, 0.06% in 2001, and 0.00% in 2002.

Even if one were to consider the full amount of SNEPCO proved reserves (0.109 bboe) that Shell restated as at year-end 2002, those reserves constituted only 2.4% of the

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66 *See* Doc. #SMJ00025310-14; Doc. #WCK00640725-26; Doc. #RJW00830133.

67 *See* Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (Doc. #V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW00082535-49); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW00321825-37).

68 *See* Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW01000022-37).

total 4.47 bboe restated.[69] Thus, SNEPCO's additions to any overstatement of proved reserves during the Class Period were inconsequential under any analysis, and any preparatory technical services that SDS might have rendered to SNEPCO in connection with that minimal amount of recategorized reserves were even more remote from any alleged fraud.

B. **Shell Development Angola ("SDAN")**

SDS also provided technical assistance to SDAN, which managed Shell's interest in the deepwater resources off the coast of Angola, including Block 18, the acreage relevant to this litigation. SDAN maintained offices in Luanda, Angola, and in Rijswijk, the Netherlands (and later in London, England). Its staff included a General Manager, a Finance Manager, an Economist, an Exploration Manager, an Asset Manager for Block 18, and additional reservoir engineers.[70] Robert Inglis was the Block 18 Asset Manager during the Class Period. None of these employees worked in the United States.[71]

SDAN did not actually operate Block 18. Rather, SDAN was a 50% partner in a joint venture with a subsidiary of BP p.l.c. ("BP"), and BP operated the field. Because BP handled the operational work, SDAN maintained only a small technical staff. BP, in contrast, had approximately 50 employees in Angola, including a number of reservoir engineers and other technical experts.

1. **SDS's Technical Services for SDAN**

Although it did not operate Block 18, SDAN was responsible for evaluating BP's planning and development work. To do so, SDAN sought technical assistance from SDS.

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69 Cooper Decl. ¶¶ 62-63 and accompanying table.

70 Duhon Dep. at 45:21-47:7.

71 Inglis Decl. ¶ 5. Mr. Inglis also was deposed on September 29, 2006.

(Before SDS's creation in 1999, its Rijswijk precursor had provided technical assistance to SDAN.)

To perform the technical service tasks contemplated by its CTR agreement with SDAN, SDS established a technical team solely devoted to working on Block 18. During the Class Period, Ian Hines was the Technical Team Leader for this group, and Derek Newberry was a Subsurface Coordinator for this team.[72]

The technical services that SDS provided to SDAN included geological analysis of deepwater reservoirs, seismic assessment of the subsurface depth and location of deepwater reservoirs, analysis of data to determine the appropriate type and placement of wells, analysis of the outcomes from drilled wells, and documentation and reporting to SDAN about the findings associated with the technical work accomplished.[73]

2. **SDS's Work in Connection with SDAN's Hydrocarbon Reserves**

Like SNEPCO, SDAN had to submit its own ARPR to EP's headquarters in the Netherlands.[74] Each year, SDAN made the final decisions about SDAN's ARPR submission, and an SDAN staff member (located in either Europe or Luanda) then signed it and submitted it to the Group Reserves Coordinator in The Hague.[75]

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[72] Ian Hines was deposed on October 18, 2004, and has submitted a declaration. Derek Newberry was deposed on September 29, 2006.

[73] Hines Decl. ¶ 12.

[74] Inglis Decl. ¶ 8; Hines Decl. ¶ 14; *see also* e-mail string in November 2001 between Grigore Simon, Robert Inglis, and Chris Duhon evaluating whether additional proved reserves would be included on SDAN's ARPR for year-end 2001. SDS personnel are not included in the discussion.

[75] *See* SDAN ARPR for year-end 1999 (Doc. #RJW00400020-033); SDAN ARPR for year-end 2000 (Doc. #RJW00400979-1005); SDAN ARPR for year-end 2002 (Doc. #RJW00080583-608).

SDAN asked SDS to provide technical evaluations of hydrocarbon resources that SDAN subsequently used as one of several inputs in preparing its ARPR submissions.[76] But SDAN made all decisions about the extent to which it would use SDS's work in SDAN's own submission of its proved reserves.[77] As Grigore Simon, SDAN's Exploration Coordinator, told Messrs. Inglis and Newberry of SDS: "It is essential for SDAN to form its own opinion about Block 18, the full field reserves, reserves that can be booked this year and next year (if any), as well as reserves sensitivity (i.e., RF variation) since ultimately all these fall under SDAN's umbrella."[78]

As discussed above in connection with SNEPCO, the estimating and reporting of proved reserves depends on numerous factors, not just a determination of hydrocarbon volumes. SDAN – not SDS – needed to make final decisions about Block 18's economic and commercial maturity and to ensure that the volume of reported proved reserves accurately reflected the operating unit's capital-allocation decisions, any limitations in the laws of and agreements with the Angolan government, and the status of the relevant market for the hydrocarbons in the ground. SDS was not capable of taking over its customers' governance and reporting responsibilities, and it never tried to do so.

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76 Hines Dep. at 203:17-19 ("[U]ltimately it's the Asset Team who are responsible for the submission, and we only provide the technical work to underpin that"); Parry Dep. at 184:9-15 ("[SDS] made calculations based on the technical data they had, on what hydrocarbons they felt were there. But they had no remit to make any proposal on reserves. That fell to Shell Angola, and ultimately through the Shell Angola reporting line").

77 Hines Decl. ¶ 13 ("SDS did not determine the quantity of proved resources in Block 18 as reported in the ARPR process but provided technical information to enable SDAN to do so").

78 E-mail dated Dec. 5, 2000 (Doc. #SMJ00017376).

3. **Irrelevance of SDAN's Proved Reserves**

Not only did SDS not make the decisions about SDAN's reported proved reserves, but those reserves ultimately are insignificant to the issues concerning the conduct test.

First, most of SDAN's recategorized reserves were reduced because they had been reported before Shell had reached a final investment decision about the project.[79] SDAN, not SDS, made decisions about project-maturity issues, which depend on commercial, business-strategy, and regulatory considerations that SDS could not resolve.

Second, SDS's technical assistance had the effect of reducing the quantity of proved reserves that SDAN reported.[80]

Third, SDAN reported new proved reserves only twice during SDS's existence (and during the Class Period): 75 million boe for year-end 2000 and an additional 46 million boe for year-end 2002. These additions amounted to only 0.39% of Shell's total reported proved reserves for 2000 and only 0.24% of Shell's total reported proved reserves for 2002.[81] The additions also constituted only a trivial portion of the total amount of recategorized reserves: 0.00% for 1999, 1.55% for 2000, 0.00% for 2001, and 1.03% for 2002.[82] And the full amount of

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[79] Doc. #600000000004867.

[80] Hines Decl. ¶ 20; Barendregt Decl. ¶ 21.

[81] Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (Doc. #V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW00082535-49); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW00321825-37); Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (Doc. #RJW01000022-37).

[82] Cooper Decl. ¶ 23 and accompanying table.

SDAN proved reserves (0.021 bboe) that Shell recategorized or restated as at year-end 2002 constituted only 0.47% of the total 4.47 bboe recategorized or restated.[83]

Thus, even if SDS played any preparatory role in SDAN's reporting of new reserves, the indirect impact on Shell's reported proved reserves was utterly insignificant.

C. **Plaintiffs' Allegations About Other Operating Units**

There is no evidence that SDS's services for any other operating unit with recategorized reserves involved the provision of technical data that the operating unit used in reporting proved reserves its own ARPR submission.

For example, plaintiffs have shown interest in SDS's work for Shell Petroleum Development Company, the operating unit responsible for Shell's onshore and shallow-water petroleum resources in Nigeria. But the evidence demonstrates that SDS – which specializes in *deepwater* technical work – did not provide any assistance whatsoever to this onshore/shallow-water operating unit.[84] Plaintiffs also have mentioned SDS's work for the operating unit in Brunei, but the evidence shows that SDS's technical services for that operating unit did not include volumetric work and thus had nothing to do with estimating or reporting proved reserves.[85]

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83 Cooper Decl. ¶ 40 and accompanying table.

84 Hoppe Decl. ¶ 20; McFadden Decl. ¶ 7; Okon Decl. ¶ 7.

85 Kennett Decl. ¶ 25; Bichsel Decl. ¶ 17; Sears Dep. at 72:8-12.

FACT SUPPORT

VII. SHELL DEEPWATER SERVICES

A. General

1. Formation of Shell Deepwater Services ("SDS")

a) SDS was formed in 1999 in Houston to create a single location that could provide expertise and knowledge regarding difficult, technical deepwater issues.

(1) Sears

(a) "[T]ypical deepwater geology for oil and gas exploration and development is particularly complex, and the exploration is difficult, and the developments are complex and difficult. And the determination was made that the best way to provide technical experts in geology, geophysics, petroleum engineering to the Shell units around the world was to have them centralized in a single organization so that their skills could be efficiently shared by all of the Shell assets." (Dep. pg. 27:7-17)

(b) "Q. I take it there were certain skills you determined should be brought within SDS, or certain areas of expertise. A. Yes. Q. What areas of expertise were those? A. Deepwater geology, turbidite geology, as well as specific geophysical skills and seismic interpretation, and deepwater experience in petroleum engineering." (Dep. pg. 33:3-11)

(2) Warren

(a) "The deepwater basins of the world at that time [were], as they still are . . . few of the remaining unexplored hydrocarbon basins of the world and represented a significant growth opportunity for companies that had the capacity and capability to explore and develop them. . . . This was very expensive exploration and production effort. So we felt it was important that we gathered all the learning in one place and that we offered a more total technical service." (Dep. pg. 51:12-17, 52:2-6)

(3) May 1999 Briefing Note: EP Leadership Forum Global Deepwater Services, at 2: "A Deepwater Services organization will be established to leverage competence and capability and provide an effective 'machine' for the execution of deepwater exploration, appraisal, development and drilling projects." (Doc. ID#103832412)

b) Houston was chosen because of its proximity to the Gulf of Mexico, where Shell had developed considerable deepwater expertise in turbidite fields.

(1) Barendregt

(a) "Since most of the progress in developing that technology had been in the Gulf of Mexico, Houston was a logical place to . . . locate this center of expertise. I say that the emphasis was on surface and subsea facilities. In addition to that, the type of fields that one tends to find in the deep off-shore are called – what geologists call turbidites, which are sand slumps off the continental shelf. . . . And these fields have specific qualities that, again, the American operation had quite some experience in." (Dep. pg. 363:9-22)

c) SDS was created by combining Shell International Deepwater Services ("SIDS"), based in The Hague, and Shell Deepwater Development Services ("SDDS"), based in Houston.

(1) SDDS had a particular focus on platforms in the Gulf of Mexico.

(a) Bichsel

(i) "[SDDS] was an organization that was charged with developing the deepwater accumulations in the Gulf of Mexico. Their particular task was to design, to fabricate and to install deepwater platforms, we have five of those in the Gulf of Mexico, as well as to tie back subsea developments into these platforms." (Dep. pg. 86:7-17)

(ii) "The SDS as an organization leveraged the fact that we had the Shell development – the Deepwater Development Services organization, which was providing engineering services to Shell Oil in the Gulf of Mexico, and that organization was incorporated into the Shell Deepwater Services and they effectively just continued seamlessly with the work that they were doing at the time." (Dep. pg. 118:15-119:2)

(2) SIDS provided technical services outside the United States.

(a) Bichsel

(i) "Shell Deepwater Development Services . . . was solely used for the development projects that we had in the Gulf of Mexico in the United States at the time, whereas Shell International Deepwater Services provided services to operating units operating outside the Gulf of Mexico." (Dep. pg. 96:9-17)

d) After the merger of SIDS and SDDS to form SDS, Rijswijk employees who remained with the combined organization moved to Houston, and the Rijswijk office ceased to exist.

(1) Varley

(a) "Q. Do you have an understanding as to why SIDS no longer exists today? A. It was an optimization of the. . . model for service provision to create a Center of Excellence for technical studies for Shell, and that Center of Excellence was termed 'Shell Deepwater Services' and was located in Houston. And many of the groups around the world doing deepwater studies, like the SIDS organization in the Netherlands, were geographically relocated from the Netherlands to form this new entity, Shell Deepwater Services, in Houston, Texas, in 2000." (Dep. pg. 34:7-22)

e) Some SDS staff members were also located in New Orleans, Louisiana.

(1) Bichsel

(a) "Q. It [SDS] . . . had offices in Houston, Texas and in New Orleans, Louisiana? A. That's correct." (Dep. pg. 106:7-10)

f) Despite the aim of creating a global center of technical excellence, SDS provided services primarily to Shell Oil Company, the U.S.-based parent company of Shell Exploration & Production Company ("SEPCo"), a United States EP operating unit.

(1) Platenkamp

(a) "Shell Deepwater Services did work for those OUs [operating units] when deepwater was part of the portfolio. Most of the work that Shell Deepwater Services did was done on the behalf of Shell Oil, to support Shell Oil with all the work done in the Gulf of Mexico where we had a number of deepwater developments ongoing, and in production already." (Dep. pg. 272:7-16)

g) Operating units turned to SDS for their most difficult deepwater technical problems.

(1) McVeigh

(a) "In Shell Deepwater Services we have some of the most talented oil and gas professionals within any discipline, be it geologist, a geophysicist, a reservoir engineer. As with all jobs, you'll have the more bread-and-butter standard kind of work, and then you'll have the more high-end, the more complex, the more challenging pieces of work. Our job was much more the more high-end pieces of work because these [deepwater] regions – again, taking SNEPCO as an example, they have 90 staff. They have some very capable people. They're doing a lot of work themselves." (Dep. pg. 99:23-100:10)

2. SDS's position within the corporate structure of Shell and relationship with operating units.

a) SDS is a division of Shell International Exploration & Production, Inc. ("SIEP Inc."), a fourth-tier subsidiary of Shell.

(1) Varley

(a) "Q. So is it fair then to say that Shell Deepwater Services is a group within SIEP, Inc.? A. That would be a reasonable way of describing it, yes, but I don't think the only group within SIEP, Inc." (Dep. pg. 30:25-31:5)

(2) McFadden

(a) "Q. SIEP is a different organization, is that correct, than SDS? A. No, SDS was part of SIEP." (Dep. pg. 124:2-4)

b) SDS entered into a Cost, Time and Resources ("CTR") contract that detailed the nature and scope of the technical services the operating unit required from SDS and outlined SDS's compensation.

(1) Bichsel

(a) "We had a clearly established protocol on how Shell Deepwater Services interacted with other Shell entities. . . . The way that operated was that we had agreements . . . we called them the cost, time and resources document, CTR for short. . . . And that CTR document spelled out what services, the scope of the services, the time these services would take, the expertise that these services demanded that . . . Shell Deepwater Services [would] provide to these operating units." (Dep. pg. 120:6-8, 121:7-17)

(b) "SDS was a service organization that provided technical services on demand to various Group operating units that were conducting deepwater operations. Each operating unit would enter into a written agreement with SDS called a Cost, Time and Resources agreement ('CTR') that detailed the nature and scope of the technical services that the operating unit required. These services included subsurface evaluation, well engineering or drilling, and development engineering, among others." (Decl. ¶ 7)

(2) Varley

(a) "SDS's work for SNEPCO was performed pursuant to a Cost, Time and Resources ('CTR') agreement, which detailed the work to be done and the cost and schedule for its completion." (Decl. ¶ 13)

(3) May 1999 Briefing Note: EP Leadership Forum Global Deepwater Services, at 3: "The provision of mandatory services will vary for each OU/NVO [*i.e.,* operating unit/ new venture organization], and will be agreed by both parties." (Doc. ID#103832412)

c) The relationship between the operating units and SDS was a "vendor/vendee" relationship or a "customer" relationship in which SDS played a consulting role.

(1) Sears

(a) "We were an internal service provider, so a reasonable characterization would be vendor/vendee." (Dep. pg. 24:6-8)

(2) Knight

(a) "We regarded them as our customer. We were supplying services. Essentially like a contractor." (Dep. pg. 25:14-16)

(3) Varley

(a) "Q. How would you categorize your relationship with Mr. McFadden? A. He was my customer. Q. And when you say 'customer,' what do you mean by that? A. It means that he requested of me and my team to provide technical services, and . . . that's what we did." (Dep. pg. 113:10-17)

(4) Minderhoud

(a) "Q. And what would be considered a service unit? Is SDS a service unit? . . . . A. A service unit I would interpret as a unit that has no direct responsibility for any particular asset except the assets that they have in their offices, if you like, or laboratory, but provides support, advice, measurements, calculations on a contract basis to customers. And the customers are the asset teams. . . . I believe that SDS was a service provision, it was a service that fit that model." (Dep. pg. 44:17-45:5)

(5) Duhon

(a) "Q. At that time did you have an understanding of what Shell Deepwater Services was? . . . . A. My understanding was that they were a contractor." (Dep. pg. 78:12-18)

d) SDS maintained its technical integrity in providing technical services for operating units.

(1) June 2, 2000 Email from C. Wilhelm (SDS) to J. Sherman (SDS): Wilhelm, in response to a request from SNEPCO for technical inputs, instructs Sherman: "We must maintain technical credibility or else the whole concept of a global center of excellence goes out the window." (WCK00640725-26)

(2) June 2, 2000 Email from B. Knight (SDS) to S. McFadden (SNEPCO): "Whilst we are always open to discussions to improve our understanding of the technical issues, SDS cannot support SNEPCO if they arbitrarily deviate from these [volumetric] estimates. If you believe these are incorrect we would appreciate learning on what data you are basing your estimates so that we can engage in a constructive dialog to reach a point where we can both support the Erha volumes." (SMJ00025310-14)

(3) Hines

(a) "SDS's goal was to maintain its technical integrity and credibility, providing independent and accurate technical data to its customers." (Decl. ¶ 19)

B. <u>SDS Organization and Technical Services Provided</u>

1. SDS provided technical services to operating units. SDS did not take over the operating units' obligation to estimate and report their proved reserves.

a) Knight

(1) "SDS was a combination of an evaluation, subsurface evaluation group and a surface facilities group, or a sub sea facilities, the hardware associated with developing those opportunities. And we were asked to provide sometimes evaluation services, mostly pre exploration, sometimes post exploration, sometimes it was supporting the possibility of making bids of acreage that companies around the world do, that want help in understanding what the costs could be and the time frame for development." (Dep. pg. 23:25-24:12)

b) May 1999 Briefing Note: EP Leadership Forum Global Deepwater Services, at 3: "Shell Deepwater Services['] role is to provide technical services in support of the approved strategic direction. Similarly, Shell Deepwater Services is not involved in other processes normally associated with asset ownership, except as requested to fulfill a technical supporting role. The asset owner will maintain responsibility for strategy, business planning, investment decisions, business representation, and local and partner contacts and issues. The governance structure for OUs and NVOs will remain unchanged." (Doc. ID#103832412)

c) Bichsel

(1) "At all times, the operating unit held the final responsibility for estimating, and did estimate, its own oil and gas resources and submitting those estimates to E&P. As requested by the operating unit, SDS provided the technical services detailed in the CTR agreement. These technical services did not include ARPR submissions. The ARPR process was handled entirely by the individual operating unit, which made all decisions regarding review, reporting, and submission of ARPR data." (Decl. ¶ 8)

d) Varley

(1) "During my employment at SDS, SDS was never responsible for estimating or reporting proved reserves, and never did estimate or report proved reserves, related to the Bonga field [of SNEPCO]." (Decl. ¶ 10)

2. Evaluation and Development Planning ("EDP"), the division within SDS that Plaintiffs have focused on, was only one of four divisions of SDS.

a) Knight

(1) "The organizational structure [of SDS] had essentially a director in charge of it. . . . Underneath that there was four basic units. There was an evaluation and development planning unit, there was a wells unit, there was a project execution unit, and a finance unit." (Dep. pg. 45:13-20)

C. <u>What SDS Was *Not* Responsible For</u>

1. SDS was not an operating unit and therefore did not carry the responsibilities of one.

a) Darley

(1) "SDS did not operate activities in the deepwater. SDS executed activities on behalf of an operating company. So if we talk about the Gulf of Mexico, SEPCo was the operating Company . . . . Nigeria in the Deepwater was SNEPCO. So the work of SDS was very much in support of the activities of those operating units. So when we talk about Deepwater activities and the execution of those and

the operation of those activities, yes, SDS played a role in support, advice and conduct of particular studies. But the operation of those activities was always the responsibility of the local operating company." (Dep. pg. 271:18-272:9)

b) Warren

(1) "Shell Deepwater Services offered a range of services from exploration through to construction. They didn't operate, but they offered services through exploration, drilling, facility construction to our deepwater operating units." (Dep. pg. 131:16-21)

2. SDS was not responsible for any Annual Review of Petroleum Resources ("ARPR") submission; nor did it ever submit one.

a) Bichsel

(1) "SDS provided the service that did not include the review of ARPRs. The ARPR data, the submission of ARPR data, the reporting of ARPR data is done via the operating units." (Dep. pg. 155:2-6)

b) Hines

(1) "Shell Deepwater Services . . . is a technical service provider, has no jurisdiction over governance, strategy or submissions of ARPRs, Reserves Statements. They are – responsibility for that is vested in the Asset Teams. . . . " (Dep. pg. 122:25-123:5)

c) Newberry

(1) "I cannot comment on the decision on reserves, booking the reserves volume that year. That was a decision for Shell Development Angola." (Dep. pg. 117:8-10)

d) September 20, 2002 Email from B. Ward (EPG, the Regional Directorate of Sub-Saharan Africa) to K. Okpere (SNEPCO): "De-booking of reserves must be endorsed by myself and Excom before any action is taken." (Doc. ID#101328316)

3. SDS did not make decisions regarding commerciality of a field. Even in situations where SDS was providing technical assistance in connection with the calculation of hydrocarbon volumes, the operating units made decisions regarding commerciality, production-sharing contracts, and license issues.

a) Knight

(1) [With respect to the SNEPCO audit report for 2002] "Q. At the end of the second paragraph it says, 'the reserves revisions had been prepared by staff in Shell Deepwater Services, SDS.' Is that an accurate statement? A. I find it a strange statement to make since SDS just did technical work and then passed the technical work on to the assets of the operating units who made the submissions. Q. Now, when you say technical work, is it correct that the technical work culminated in SDS giving a number to operating units, is that correct? A. It can be a number or it can be a range. And then they are much more aware of the commercial, economic and political environment and other factors that may come into play. Q. But when the technical work is done, it culminates in either a range of volumes or a particular number, is that correct? A. Yes, that is usually the situation. But what then the operating company does with that is something we're not always party to. Sometimes we're not even copied on that sort of information." (Dep. pg. 158:4-159:3)

(2) November 2, 2000 Email from I. Hines (SDS) to R. Inglis (SDAN) regarding an upcoming meeting with the Group Reserves Auditor ("GRA"): "We have not updated our economics since the VAR [Value Assurance Review] since you indicated that we have not been treating the costs correctly and were awaiting your guidance note – it would probably be best if we provide the costs and production profile data and let you run the economics." (WCK00010045-47)

4. Proved reserves were not a metric on SDS's scorecard.

a) Knight

(1) "Q. Do you recall whether proved reserve volumes was ever a metric on SDS's scorecard? A. I do not believe it was ever a metric on SDS scorecard." (Dep. pg. 144:12-15)

(2) "Q. Was SDS sensitive to scorecard requirements in doing its work with respect to potential proved reserves bookings? A. I do not recall that. We were very sensitive actually to delivering the output that we promised." (Dep. pg. 145:17-22)

b) Varley

(1) "Q. What would some of the other inputs – with respect to the interaction between SNEPCO and SDS, how would some of that interaction be reflected on the SDS scorecard? A. I believe the degree to which we had matured an opportunity through various decision gates leading from discovery to sanction of the project and so on and so forth, the degree to which we had produced the results successfully, passed independent reviews and decision gates, and matured those opportunities, I believe that was also something on the scorecard, that we reflected the Operating Unit's performance in that regard. . . . . Q. What kind of results are you referring to? A. The results of a simulation model; when the well is put on stream, how much oil or gas will flow from that well, at what rate over what period of time, collectively how much of those volumes would be produced by the field. That's what we call results, the results of a model or a simulation model on the computer. Q. Is one of the [types] of results the categorization or calculation of reserves? A. No. The outcome is a volumetric estimate. Categorization of reserves is something entirely different." (Dep. pg. 139:13-140:6-19)

5. SDS did not communicate with Shell's external auditors.

a) Knight

(1) "Q. Do you know who Shell's outside auditors are or were during the period '99 through 2003? A. I think it might have been KPMG. Q. In your work did you ever have any personal interaction with anyone from KPMG? A. None whatsoever. Q. Have you ever had any personal interaction with anyone from PricewaterhouseCoopers? A. None whatsoever." (Dep. pg. 159:19-160:-5)

b) Newberry

(1) "Q. Have you – during your time working at SDS for Angola Block 18, did you ever have any interaction with either KPMG or PricewaterhouseCoopers? A. No." (Dep. pg. 201:18-22)

c) Varley

(1) "Q. In conjunction with your work at SDS, did you have any reason to interact at all with any of Shell's outside

auditors? And specifically I'm talking about KPMG accountants and PricewaterhouseCoopers accountants. A. No." (Dep. pg. 196:9-14)

6. SDS had no involvement in calculating the reserves replacement ratio ("RRR").

a) Knight

(1) "Q. At this time, this document again is dated September 2002, did you believe an RRR of 100 percent was a realistic goal for Shell? A. I was not in a position to understand that, not working at the center of this sort of information. I was working at an outlying unit service provider. I do not know." (Pg. 71:11-17)

7. For two of SDS's customers – Shell Nigeria Exploration and Production Company ("SNEPCO") and Shell Development Angola ("SDAN") – members of SDS's EDP unit provided more comprehensive technical support. Plaintiffs have focused on SDS's work for SNEPCO and SDAN, so the following sections will discuss the technical services that SDS provided to those two operating units. After the discussion of SNEPCO and SDAN, we address the technical services that SDS provided to other operating units.

D. <u>SDS Involvement In SNEPCO</u>

1. Background

a) SNEPCO is Shell's operating unit for deepwater operations in Nigeria.

(1) McFadden

(a) "SNEPCO is a Shell company based in Nigeria that develops deepwater offshore blocks in Nigeria." (Decl. ¶ 10)

b) SNEPCO, which operated in deepwater fields, is entirely different from Shell Petroleum Development Company (Nigeria), Ltd. ("SPDC"), which operated in onshore and shallow water fields.

(1) Hoppe

(a) "SPDC operated petroleum fields and facilities in the onshore and shallow offshore environments of Nigeria, on behalf of a joint venture with the Nigeria National Petroleum Company and other oil and gas companies. SNEPCO was a separate Shell company that operated in the deepwater environment offshore of Nigeria. SPDC and SNEPCO had separate technical staffs, including their own engineers, geologists, and geophysicists." (Decl. ¶¶ 10-12)

(b) "SNEPCO also prepared its own ARPR and submitted it to the Group Reserves Coordinator in the Netherlands, but SNEPCO's ARPR process was entirely separate from and independent of SPDC's." (Decl. ¶ 15)

(2) Roosch

(a) "There's two Nigerias. There is the regular Shell Nigeria operation, SPDC, and there is SNEPCO, which is deepwater only." (Dep. pg. 96:4-6)

(3) Van de Vijver

(a) "Q. Were the SPDC and SNEPCO offices geographically separate? A. Yes." (Dep. pg. 164:11-13)

(4) SNEPCO is much smaller and less well-known than SPDC in Nigeria.

(a) McFadden

(i) "[H]aving spent eight years in Nigeria, it's not uncommon for reporters in Nigeria to mix up SNEPCO and SPDC, because the only company that they're mostly aware of in Nigeria is SPDC because it's the major company operating there for Shell. SNEPCO is oblivious to most people in Nigeria. It doesn't have the same profile." (Dep. pg. 64:5-9)

c) The only operating unit in Nigeria to which SDS provided technical assistance was SNEPCO; SDS had no involvement with SPDC.

(1) Okon

(a) "Shell Deepwater Services ('SDS') was never involved in the EA project [in SPDC], because it was a shallow-water development project rather than a deepwater one." (Decl. ¶ 7)

(2) Aalbers

(a) "Q. Do you recall if SDS did any work in the EA field? A. No. SDS was looking at the deepwater, and this was shallow. So their expertise wasn't on the shallow, but on the deepwater." (Dep. pg. 281:12-16)

(3) Hoppe

(a) "I never had any contact with SDS or any SDS employees with respect [to] the EA field or any other SPDC fields." (Decl. ¶ 20)

(b) "[A]ny production forecasts that were included as part of the information SPDC used to estimate and report its resource volumes to the Group Reserves Coordinator in the Netherlands were produced by SPDC in Nigeria without any input from SDS or any other United States-based entity." (Decl. ¶ 21)

(4) McFadden

(a) "To my knowledge, no technical work was performed for SPDC by a Group service company known as Shell Deepwater Services ('SDS')." (Decl. ¶ 7)

2. SDS provided technical services for SNEPCO in the Bonga Main, Bonga Southwest, Erha, and Abo fields.

a) Varley

(1) "I was responsible for supervising and coordinating the activities of the . . . team that provided technical services to Shell Nigeria Exploration and Production Company ('SNEPCO'), the local Shell operating unit based in Nigeria that operated the Bonga fields." (Decl. ¶ 5)

(2) "[We] prepared feasibility studies, concept-selection studies, primary field development plans, and proposals used to facilitate the drilling of development wells in the Bonga fields in Nigeria." (Decl. ¶ 8)

b) Roosch

(1) "Q. Was Shell Deepwater Services involved in the SNEPCO Bonga Southwest reserve? A. They were involved in the technical work, which is underlying the reserve submissions by the asset holders." (Dep. pg. 96:22-97:2)

c) McVeigh

(1) "Q. And with respect to your team, what specific fields did you interact with in Nigeria? Which fields were you responsible to interact with in Nigeria for? You said Mr. Varley was the Team Leader for the Bonga team, correct? A. Correct. Q. So I'm curious as to what fields or teams you would have interacted wih. A. The [Erha] field in OPL 209, and the Abo field in OPL 133 . . ." (Dep. pg. 69:14-23)

3. SNEPCO, not SDS, was responsible for estimating and reporting its own proved reserves, and SDS did not estimate or report SNEPCO's proved reserves.

a) McFadden

(1) "SDS was not responsible for estimating, and did not estimate, proved reserves for SNEPCO. Furthermore, SDS was not responsible for reporting, and did not report, SNEPCO's proved reserves to E&P headquarters in The Hague. The models and forecasts that SDS generated included estimates of hydrocarbon volumes, but those estimates could not be reported to E&P headquarters as reserves without further work by SNEPCO in Nigeria." (Decl. ¶ 13)

(2) "Q. Now, I'd like to go back to what we were discussing a little while ago, the ARPR process. Could you describe for me what your duties and responsibilities at SNEPCO were in connection with that process? A. Well I basically supervised the reservoir engineers who worked on that and ensured that we were getting the right data that we required from, from the group doing the modeling in Houston, and also that we were getting the right data from partners that we needed to input in that. I also liaised with the development planning group because the reserves calculation process for the PSC [*i.e.* production sharing contract] involves putting – running economics and inputting cost data as well in the economic model to get an entitlement share, which is the number that's reported at the

end of the day. So there was a number of various different sources of information that went into the reserves – in the final reserves number and different people who were involved in the calculation. For instance, the economics were run by the economics and planning group. The cost data was QC'd and controlled through the development/planning group. And my group looked at the forecasting data, but then took the final numbers and reported those in the ARPR report." (Dep. pg. 68:7-69:8)

b) Bichsel

(1) "At all times . . . SNEPCO, not SDS, held the final responsibility for estimating its oil and gas resources and submitting those estimates to E&P headquarters in the Netherlands." (Decl. ¶ 10)

c) Varley

(1) "I am unaware of anyone at SDS who was involved in the preparation or submission of SNEPCO's ARPR. Indeed, my recollection is that only SNEPCO engineers and economists were involved in the preparation of the ARPR and other proved-reserves reporting responsibilities at SNEPCO." (Decl. ¶ 12)

d) November 21, 2001 Email from O. Uzoh (SNEPCO) to C. Varley (SDS): "Please be advised that Ekong Asanga has taken over the role of the SNEPCO Reserves Co-ordinator. He will be responsible for the 2001 ARPR submission for SNEPCO." (Doc. ID#200000004279263)

4. SNEPCO submitted its ARPRs from its headquarters in Nigeria to the Group Reserves Coordinator at EP headquarters in The Hague. SNEPCO's ARPRs were signed by SNEPCO's Petroleum Engineering Manager in Nigeria for all years of the Class Period.

a) McFadden

(1) "While employed by SNEPCO in Nigeria, I was responsible for . . . the annual review of petroleum resources ('ARPR'), an annual submission that each operating unit made to the headquarters of Shell's Exploration and Production ('E&P') business in The Hague, the Netherlands, detailing that operating unit's oil and gas resources." (Decl. ¶ 11)

(2) "The computed Shell entitlement share was given [by SNEPCO's economics and planning group] to my department, the petroleum engineering group, also located in Nigeria. The petroleum engineering group shared the data with the senior SNEPCO reservoir engineer, who collated the data and prepared the ARPR report for SNEPCO. The reservoir engineer then sent me SNEPCO's draft ARPR. After reviewing the report in Nigeria, I sent it to the Group Reserves Coordinator, who worked at E&P headquarters in the Netherlands." (Decl. ¶¶ 13-14)

b) SNEPCO's Petroleum Engineering Manager in Nigeria (Osten Olorunsola for year-end 1999 and 2000, and Tunde Ogunnaike for year-end 2001 and 2002) signed SNEPCO's ARPRs for all years of the Class Period.

(1) SNEPCO ARPR submission for year-end 1999 (RJW00400629-46); SNEPCO ARPR submission for year-end 2000 (RJW00401617-49); SNEPCO ARPR submission for year-end 2001 (RJW00070678-706); SNEPCO ARPR submission for year-end 2002 (RJW00080376-404)

5. Although SDS provided estimates of hydrocarbon volumes to SNEPCO, those estimates could not be reported as proved reserves without further economic, business, strategy and commercial analyses, which were indispensable aspects of the proved reserves estimating and reporting process and for which SNEPCO in Nigeria held sole responsibility.

a) SNEPCO had an Economics Group located in Lagos that was solely responsible for running economics related to the estimation and reporting of SNEPCO's proved reserves.

(1) Varley

(a) "Mr. van der Lee or the Economics Group in SNEPCO would have been responsible for executing all the economic calculations and tests related to reserves issues." (Dep. pg. 102:25-103:4) (Varley is also questioned about various other SNEPCO employees, all of whom are located in Lagos.)

(2) McVeigh

(a) "So whenever we needed any economics – whenever we needed any economics done from 2000 to 2004, given that we were not in receipt of SNEPCO's economic model, we could not run economics, so we would have to get input data, send it Arun Agrawal. He would then get it run through the economic cost model in Lagos, and then send the results back to us." (Dep. pg. 133:10-17)

(3) May 31, 2002 Email from T. Lim (SDS) to E. Enu (SDS) attaching a document with economic data generated by SNEPCO: Lim explains: "There are some economics tables, graphs and project schedule attached (all generated by them [SNEPCO], not SDS)." (SMJ00026546)

(4) April 26, 2002 Email from C. Varley (SDS) to M. Distel (SNEPCO) and C. Shotton (SNEPCO) that shows SNEPCO ran economics: Varley thanks Distel and Shotton "for the rapid turn-around of economics results" and then states, "I have a question about how you run economics for Bonga-SW. Do you run incremental economics for Bonga-SW as an investment opportunity on top of Bonga Main + IFO, or just on top of Bonga Main (without the IFO)." (SMJ00030357-61)

(5) November 30, 2001 Email from J. Van Der Lee (SNEPCO) to O. Uzoh (SNEPCO) and R. Hoffmann (SNEPCO), in which he discusses SNEPCO's responsibility for calculating Shell's entitlement share, which is a necessary step in estimating and calculating proved reserves: "I have just reviewed where we stand with data received in SNCP [SNEPCO Corporate Planning and Economics] for input into the economic modeling. I am very disturbed by the little progress that has been made into getting data from SDS to SNPE [Head of SNEPCO Petroleum Engineering] to SNDV [SNEPCO Projects Development] to SNCP. . . . SNCP (economics) is at the end of the chain and we only have OML 118 (Bonga Main + IFO not received yet). Our task is to calculate the PSC Shell entitlement for booking Shell reserves (and the standard measure calculations)." (SMJ00034283-88)

b) SNEPCO could not estimate or report its proved reserves to Shell headquarters in the Netherlands without first analyzing numerous non-volumetric considerations, such as economics, business strategy, and commercial issues.

(1) McFadden

(a) "The models and forecasts that SDS generated included estimates of hydrocarbon volumes, but those estimates could not be reported to E&P headquarters as reserves without further work by SNEPCO in Nigeria. Upon receipt of SDS's forecasts and models, SNEPCO gave them to its economics and planning group located in Lagos, Nigeria. The economics and planning group ran economics using the terms of the production sharing agreement to calculate Shell's entitlement share of the proved reserves for the fields in which SNEPCO owned an interest." (Decl. ¶ 13)

c) SNEPCO, and not SDS, was responsible for making judgments concerning the commerciality of projects and assets, including capital allocation, cost expenditures, and the interpretation of SNEPCO's Production Sharing Contract ("PSC"). SNEPCO was also responsible for interaction with the Nigerian government.

(1) McFadden

(a) "Q. Was SDS involved in determining capital expenditure or costs associated with projects going forward? A. No, no. Q. Was that a SNEPCO process? Was that handled within SNEPCO? A. That was handled within SNEPCO and as part of the capital allocation . . . in Holland." (Dep. pg. 84:3-11)

(b) "With SNEPCO, yes, we did talk to Government officials. We talked to people, particularly in the DPR [Nigeria Department of Petroleum Resources] which was a regulatory group, because well proposals had to be discussed with – approved by the DPR. The DPR had to approve field development plans. So we were involved in a number of presentations to the DPR involving presenting field development plans and well proposals." (Dep. pg. 31:15-25)

(c) "Q. Did SDS have any additional role after they forwarded the forecasts back to SNEPCO? A. Not in the reserves reporting process. Q. After you received the forecasts back from SDS, what was done with that data or information at SNEPCO? A. That data was then passed on to the economics and planning group, together with the cost data that we would get through . . . the development/planning group in SNEPCO. They would run economics using the terms of the PSC to calculate the Shell entitlement share under the PSC, and that was the number which we reported . . . in the ARPR. Q. Where was the economics and planning group located? A. Economics and planning group was located in SNEPCO in Lagos." (Dep. pg. 71:22-72:14)

(2) September 26, 2002 Email from S. McFadden (SNEPCO) to A. Barendregt (Group Reserves Auditor): "Royalties and License periods. . . . We have clarified the situation on royalties with SNCP – see attached mail and what we have been doing up to now we believe is correct." (Doc. ID#200000004556373)

6. SDS provided technical services for SNEPCO in the Bonga Main, Bonga Southwest, Erha, and Abo fields, but did not estimate or report proved reserves in those (or any other) fields for SNEPCO.

a) Bonga Main

(1) Proved reserves were reported for Bonga Main in the YE 2000 process, but no additional proved reserves were reported.

(a) Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (RJW00082535-49); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (RJW00321825-37); Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (RJW01000022-37).

(2) SDS provided only technical assistance that SNEPCO requested for the Bonga Main field.

(a) Varley

(i) "A. It was [my job at SNEPCO as Bonga team leader] to supervise and coordinate the activities of my team members. Q. And what activities were those? A. Provision of technical services to SNEPCO, producing some of the documents that we talked about before: Feasibility studies, concept selection studies. Primarily field development plans was a large portion of the work, and well proposals for the drilling of development wells on the Bonga field." (Dep. pg. 74:9-20)

(ii) "During my employment at SDS, SDS was never responsible for estimating or reporting proved reserves, and never did estimate or report proved reserves, related to the Bonga field. SDS's work included the determination of hydrocarbon volumes in subsurface reservoirs, but those hydrocarbon volumes could not be reported by SNEPCO as proved reserves to E&P without further economic and legal analysis by SNEPCO, which was carried out in SNEPCO's offices in Nigeria." (Decl. ¶ 10)

(b) Kennett

(i) "[T]o determine proved reserves entitlement for Shell is more than just volumetric calculations. You have to calculate the entitlement proportions under the PSC, because the profit oil for the government is not part of your entitlement. Your entitlement includes the cost oil. The cost oil of Bonga is based on the cost of Bonga. Bonga was project managed by SNEPCO. And the costs for Bonga is part of that economics. And the economic models reside in Lagos. So the bottom line is this SDS is only responsible for one of the components of the reserves evaluation for Bonga. The economic evaluation, the cost oil, the government profit oil calculations are all done in Nigeria in SNEPCO. . . . The ARPR is run by SNEPCO, the inputs to the ARPR, and the inputs to the reserves reporting in SNEPCO Nigeria, Lagos." (Dep. pg. 270:11-271:8)

b) Bonga Southwest

(1) No proved reserves were ever reported in the Bonga Southwest field. Therefore, Bonga Southwest could not have made any contribution to the alleged fraud involving

the overstatement of Shell's proved reserves.

(a) Barendregt

(i) "No proved reserves were ever reported for the Bonga SW field, meaning that no technical work that SDS might have performed regarding that field led to an overstatement of proved reserves." (Decl. ¶ 20)

(2) SDS provided only technical assistance that SNEPCO requested for the Bonga Southwest field.

(a) Roosch

(i) "Q. Was Shell Deepwater Services involved in the SNEPCO Bonga Southwest reserve? A. They were involved in the technical work, which is underlying the reserve submissions by the asset holders. Q. Do you know what the nature of that technical work was? A. The nature was geological evaluation, petrophysical evaluation and reservoir delineation and development planning, and hardware was a very important aspect." (Dep. pg. 96:22-97:8)

(ii) "I am not aware of SDS's having made any recommendations about the booking of reserves for Bonga Southwest, and in fact no proved reserves were booked for Bonga Southwest during my tenure." (Decl. ¶ 9)

c) Erha and Abo fields

(1) New proved reserves were reported for Erha and Abo at year end 1999 and, to a very small degree, year end 2000.

(a) Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (RJW00082535-49).

(2) The work that SDS performed for SNEPCO, however, related to the technical assessment of those fields and was not related to the estimating or reporting of proved

reserves.

(a) McVeigh

(i) [In reference to McVeigh Exhibit 5, a document titled "Erha Field Development Nigeria"] "Q. If you look at the first line of the fourth paragraph on the first page, it says booked reserves are 240 million bbl Shell share, of which 165 million bbl are proven. . . . Do you have any understanding as to whether or not the information contained in there, presumably as of June 5th, 2002, is correct? . . . . A. I think I've been quite clear telling you that I have no impact or responsibility for reserves in any way, shape or form, so how could I possibly tell you whether that was correct or not?" (Dep. pg. 139:8-15, 139:20-23)

(ii) "My job has nothing to do with reserves. We do technical work on behalf of the asset owner, which is SNEPCO." (Dep. pg. 69:16-18)

(iii) "In the course of doing our technical work, that technical work would then be sent to SNEPCO and it would be then for SNEPCO to take that work and undertake the reserves submissions themselves. That's handled completely and utterly by the asset owner, which is SNEPCO." (Dep. pg. 74:25-75:6)

(iv) "Q. What is your understanding of the term ARPR? A. That's an internal procedure within SNEPCO. It's a year-end reporting of their various volumes. Q. Did you personally play any part in the ARPR production by SNEPCO during the four years that you were employed by SDS? A. The only part myself or my team would ever be involved with ARPR, because again going back to my previous point, ARPR is part of governance which means it's the asset owner that do[es] that work. It has nothing to do with us. All we do would be to provide technical input data, which then they would go and work and they would run through their economics." (Dep. pg. 75:15-76:3)

(v) "I would have no reason in my job as the NOV [Non-Operated Venture] Nigeria Team Leader to talk to Anton Barendregt. Anton Barendregt was a reserves auditor. He would be talking to people in SNEPCO." (Dep. pg. 106:15-18)

(vi) "Q. Do you know the name of anyone who did participate in the booking of reserves for the Ehra [*sic*] field? A. They would be staff in SNEPCO, so – it's their responsibility." (Dep. pg. 109:7-12)

7. The fact that Anton Barendregt, the Group Reserves Auditor, conducted a proved reserves audit of SNEPCO from September 9-12, 2002, in Houston does not change the fact that SNEPCO, not SDS, was responsible for estimating and reporting its own proved reserves. SEC Proved Reserves Audit – Shell Nigeria E&P Co (SNEPCO), 9-12 Sept 2002 (RJW00830131-41).

a) Barendregt incorrectly described the relationship between SNEPCO and SDS, as SDS was not responsible for and did not perform reserves revisions.

(1) Knight

(a) "Q. At the end of the second paragraph it says, 'The reserves revisions had been prepared by staff in Shell Deepwater Services, SDS.' Is that an accurate statement? A. I find it a strange statement to make since SDS just did technical work and then passed the technical work on to the assets of the operating units who made the submissions." (Dep. pg. 158:4-11)

8. SNEPCO's proved reserves are ultimately irrelevant to the conduct test analysis.

a) Most of SNEPCO's proved reserves at issue in the case were first reported at year-end 1998 or earlier, before the formation of SDS in and before the beginning of the Class Period. SNEPCO carried forward previously reported reserves in subsequent years.

(1) Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (RJW00082535-49); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (RJW00321825-37); Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (RJW01000022-37).

b) Most of the reductions in SNEPCO's proved reserves numbers were due to *project maturity* considerations – such as reporting the reserves as proved before reaching a final investment decision – about those fields that were unrelated to the *technical* services that SDS provided to SNEPCO.

(1) Proved Reserves Booking Lookback, June 2004: The majority of reductions in proved reserves in SNEPCO resulted from a lack of "project maturity." (Doc. ID#600000000004867)

(2) Cooper

(a) "The reduction in proved reserves for SNEPCO in 2002 was primarily due to lack of project maturity." (Decl. ¶62)

c) The new reserves added during SDS's existence also constituted only a miniscule percentage of the total amount of restated reserves: 2.66% in 1999, 2.52% in 2000, 0.06% in 2001, and 0.00% in 2002.

(1) Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (RJW00082535-49); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (RJW00321825-37); Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (RJW01000022-37).

d) The new proved reserves that SNEPCO added to Shell's total reported proved reserves during SDS's existence (and during the Class Period) amounted to less than 1% of Shell's total reported proved reserves for each of the relevant years. For year-end 1999, 2000, and 2001, SNEPCO reported an additional 122 million boe, 122 million boe, and 2.7 million boe, respectively. These additions constituted only 0.61%, 0.63%, and 0.01% of Shell's total reported proved reserves for those years.

(1) Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (RJW00082535-49); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (RJW00321825-37).

e) Overall, SNEPCO's proved reserves *declined* during the Class Period, as SNEPCO *decreased*, rather than increased, its proved reserves at year-end 2002.

(1) Restatement of historical proved reserves volumes: March/April 2004:

(a) SNEPCO's proved oil and gas reserves at year-end 1999 were approximately 484 million barrels of oil equivalent ("boe"). By year-end 2002, SNEPCO's proved oil and gas reserves were 480 million boe. (RJW01031152-67)

f) Even if one were to consider the full amount of SNEPCO proved reserves (0.109 bboe) that Shell restated at year-end 2002, those reserves constituted only 2.4% of the total 4.47 bboe restated. Thus, SNEPCO's additions to any overstatement of proved reserves during the Class Period were inconsequential under any analysis, and any preparatory technical services that SDS might have rendered to SNEPCO in connection with that minimal amount of restated reserves were even more remote from any alleged fraud.

E. <u>SDS Involvement In SDAN</u>

1. Background of Block 18, the asset for which SDAN reported proved reserves.

a) SDAN was not the operator of Block 18. Instead, Shell owned a 50% stake in the block, which was operated by BP p.l.c. ("BP"). SDAN and SDS relied in part on data from BP.

(1) Hines

(a) "We tried to understand the magnitude of the task required in terms of the physical technical work that needed to be done for the original Field Development Plan, and that was very significant, because we had really only just started the technical work on Block 18 as the Shell Team, and we were at that stage relying entirely, almost exclusively on the information being provided by BP." (Dep. pg.

112:10-18)

b) Because BP handled operational work in Block 18, SDAN maintained only a small technical staff, whereas BP kept approximately 50 employees in Angola, including technical experts.

(1) Hines

(a) BP had "a team of 50 people" in Angola working on Block 18, including several engineers. (Dep. pg. 79:17-21; 80:12-15)

c) SDAN had staff in Luanda, Angola, as well as in Europe.

(1) Duhon

(a) "Q. During this period did you meet any of the individuals who worked for Shell Angola? A. Yes. Q. Who do you recall meeting? A. I recall meeting -- I recall meeting five individuals. . . . Q. Were all of those individuals stationed in Angola? A. No. Q. Why don't we go through them one by one, if you could just identify who they were in the organization and where they worked. Mr. Karsten? A. General Manager, based in Luanda. Q. Mr. Inglis? A. In effect -- I may not get any of these titles specifically right. In effect he was the technical manager based in Rijswijk. Q. Mr. Simon? A. He was the Exploration Manager in effect based in Rijswijk. Q. Mr. Smits? A. He was in effect a reservoir engineer based in Rijswijk. Q. Mr. Ward? A. He was a technical assistant of some sort, just under Rob Inglis, based in Rijswijk. Q. And Ms. Sturman? A. She was the economist based in Rijswijk." (Dep. pg. 45:21-47:7)

(2) Inglis

(a) "SDAN was initially headquartered in Rijswijk, The Netherlands. In October 2003 SDAN moved its headquarters to London, England. While [SDAN General Manager, Peter] Osborne (and later [Osborne's successor] Karsten) was based in Angola, I and other SDAN were staff based first in Rijswijk and later in London." (Decl. ¶ 5)

2. Block 18 of SDAN contained reservoirs that presented more challenging

technical difficulties than other assets.

a) Parry

(1) "Block 18 was a little unusual in that the geology was very complicated and it didn't have one big accumulation, simple accumulation. It was a number of small, laterally diverse accumulations." (Dep. pg. 51:8-12)

3. SDS provided technical assistance to SDAN in Block 18 but was not responsible for the estimation of proved reserves for reporting purposes.

a) Although it did not operate Block 18, SDAN was responsible for evaluating BP's planning and development work, and sought technical assistance from SDS to do so.

(1) Hines

(a) "A. The group that I was working in was a Field Development Planning Unit, which is a service provider to the customer; in this case, Shell Angola. Q. Do you know why your group was asked to provide this technical advice? A. They had no surface engineering, facilities engineering expertise in the Shell Angola team, and they wanted someone to give them advice about the appropriateness of BP's plans for development of Block 18." (Dep. pg. 38:11-21)

b) SDS formed a team solely devoted to providing technical assistance to SDAN in Block 18. Ian Hines was the Technical Team Leader, and Derek Newberry was the Subsurface Coordinator.

(1) Hines

(a) "In 2000, as a consequence of SDAN's request for assistance, SDS formed a Block 18 Technical Team of technical specialists. The newly formed team consisted initially of a reservoir engineer, a surface engineer, and two production geologists. I led this team from 2000 until 2004." (Decl. ¶ 11)

(2) Newberry

(a) "In order to provide technical assistance, SDS formed a team solely devoted to working on Block 18." (Dep. pg. 18:8-9)

c) SIDS, the Rijswijk-based predecessor to SDS, had provided technical assistance to SDAN before the formation of SDS.

(1) Newberry

(a) "SIDS, the Rijswijk-based predecessor to SDS, had provided technical assistance to SDAN before the formation of SDS." (Dep. pg. 18:9-11)

d) Hines described the technical work performed by SDS in his Declaration.

(1) "Analysis of the geological character of the deepwater reservoirs, such as analysis of the type of rock formation that exists in the reservoir and evaluation of types of sediments in the reservoir and movement of that sediment over time;

(2) Assessment of the subsurface depth and location of deepwater reservoirs, using seismic interpretation and other techniques;

(3) Analysis of the connectivity (i.e. the degree to which petroleum resources flow between different reservoirs), in a geographic area, so we could assess the appropriate type and placement of wells;

(4) Analysis of analog data, in particular from other known deepwater turbidite reservoirs (Block 18's type of geological formation) to enable us to draw conclusions about SDAN's resources;

(5) Use of petrophysics to analyze the results of wells;

(6) Calculation of estimated recovery efficiencies for the fields within Block 18;

(7) Projections related to the potential flow rate for a given well;

(8) Analysis of field development options including oil and gas production facility concepts, development costs and schedules, and development scenario comparisons, and

(9) Documentation and reporting to SDAN regarding the findings associated with any of the technical work accomplished." (Decl. ¶ 12)

4. Although SDAN was a smaller asset compared to some of the other operating units, it was nevertheless responsible for its own ARPR, including its proved reserves calculation.

   a) Email string in November of 2001 between Grigore Simon (of SDAN), Robert Inglis (of SDAN) and Chris Duhon (of EPG, the Regional Directorate for Africa) evaluating whether additional proved reserves will be included on SDAN's ARPR for year end 2001: SDS personnel are not included in the discussion. (Doc. ID#108019874)

   b) December 12, 2000 email from Grigore Simon to Derek Newberry and Ian Hines: "[i]t is essential for SDAN to form its own opinion about Block 18, the full field reserves, reserves that can be booked this year and next year ... since ultimately all these fall under SDAN's umbrella." (SMJ00017376-377.)

   c) ARPR submissions, signed and sent by SDAN staff, not SDS, to EP Headquarters in The Hague. (SDAN ARPR for year end 1999 (RJW00400020-033); SDAN ARPR for year end 2000 (RJW00400979-1005); SDAN ARPR for year end 2002 (RJW00080583-608)).

   d) Inglis

      (1) "SDAN was responsible for making reserves submissions for its assets including the calculation and reporting of 'proved' reserves. SDAN bore sole responsibility for its annual submissions to EP headquarters in The Netherlands as part of Shell's . . . ARPR. ARPR submissions for SDAN were signed every year by SDAN personel in Angola or The Netherlands and submitted to the Group Reserves Coordinator in The Netherlands." (Decl. ¶ 8)

      (2) "SDAN made the final decisions regarding its reserves submissions." (Decl. ¶ 9)

   e) Hines

      (1) "Shell Deepwater Services . . . is a technical service provider, has no jurisdiction over governance, strategy or submissions of ARPRs, Reserves Statements. They are – responsibility for that is vested in the Asset Teams, so our responsibility was to do technical work to support their ambitions." (Dep. pg. 122:25-123:7)

      (2) "[U]ltimately it's the Asset Team who are responsible for the submission, and we only provide the technical work to

underpin that." (Dep. pg. 203:17-19)

(3) "I understand that each year, SDAN personnel completed SDAN's ARPR. SDAN's ARPR was signed every year by a member of the SDAN staff (located in either Rijswijk or Luanda) and was submitted by SDAN staff to the Group Reserves Coordinator in The Hague." (Decl. ¶ 17)

f) Parry

(1) "Q. Did you mention a specific number that might be available for booking in Block 18? A. Not at that precise moment, I don't think. Q. At some point did a number – was a number suggested? A. Yes. Q. What was that number? A. As I recall, it was on the order of 293 million barrels. Q. How was that number arrived at? A. This was a number that Shell Angola arrived at. Q. Who in particular, if you recall? A. Mr. Simon. Q. Are you aware what work he undertook to arrive at that number? A. He would have analyzed the geological information and the maps and calculated the numbers in the usual way." (Dep. pg. 46:22-47:17)

(2) "[SDS] made calculations based on the technical data they had, on what hydrocarbons they felt were there. But they had no remit to make any proposal on reserves. That fell to Shell Angola, and ultimately through the Shell Angola reporting line." (Dep. pg. 184:9-15)

(3) "Q. What was the original source of that number of 74 million, if you know? A. I can't remember exactly which individual proposed that number. Q. Would that number have come from someone at SDS? A. Not to my recollection. Q. Who do you believe came up with the number 74? A. I think it would come from Shell Angola and with the concurrence of, ultimately, Anton. But I don't recall precisely the dialogue there. . . . Q. If SDS was doing the technical work, what's the basis for your believing that the number came from anyone other than SDS? A. Because the number had to satisfy the regulations and the criteria that Shell dictate. And that was the responsibility of Anton and Remco." (Dep. pg. 187:21-25, 188:2-10, 188:13-19)

g) Nauta

(1) "Q. Do you know if Shell Deepwater Services was retained

by the operating unit in Angola with regard to the booking of reserves that was made in the end of 2000 in Angola? .... A. The answer is no. They were set up to carry out services for operating units and were not accountable for decisions such as reserves bookings." (Dep. pg. 251:24-25, 252:9-10).

h) Bichsel

(1) "During my employment at SDS, SDS provided technical services for Shell Development Angola ('SDAN') relating to development of several deepwater blocks, including Block 18. SDS's work did not contribute to the initial overstatement of reserves. At all times, SDAN, not SDS, held the final responsibility for estimating its oil and gas resources and submitting those estimates to E&P." (Decl. ¶ 18)

5. SDAN could, and did on occasion, ignore the technical advice provided by SDS when SDAN disagreed with the data.

a) Email from Ian Hines to Richard Sears in which he explains a disagreement when "SDAN decided to use higher recovery factors that those recommended by SDS." (SMJ00034855-58)

6. EPG, the Regional Directorate for Africa located in Rijswijk, assisted SDAN.

a) Rothermund

(1) "Q. In terms of the development of a development plan for Angola, would that be Mr. Osborne's [of SDAN] responsibility, or would the responsibility lie in EPG? A. . . [T]he proposal as to what to do would come as such from Angola. Angola was a bit of a special organization because it was so small. So a lot of the work was really done in conjunction between Mr. Osborne, Mr. Parry [of EPG] and then the group in Rijswijk representing the Angolan group." (Dep. pg. 105:22-106:3-9)

b) SDS considered various hydrocarbon volume estimates in the course of providing SDAN with the necessary technical advice concerning, for instance, the placement of wells. The decisions concerning whether to report proved reserves and the amount to be reported, however, remained with SDAN.

(1) Parry

(a) "Q. How would you describe [SDS's] role? A. Shell Deepwater Services were providing a technical service to Shell Angola. Q. What was the nature of the technical services they provided? A. It ranged from subsurface interpretation, to geophysical data to decide where to drill wells. . . . So Shell Deepwater Services were helping Shell Angola to decide where the best well locations should be. And then laterally, they were involved in other technical aspects, reservoir engineering through to the design of notional developmental schemes to evacuate oil from the discoveries that we were making so that Shell Angola could have a detailed, in-depth debate with BP on these issues. Q. Is it fair to say that SDS . . . was a player in the discussions about whether proved reserves could be booked in Block 18 in 2000? . . . . A. "Shell Deepwater Services were providing technical analysis to Shell Angola that would help Shell Angola. It was Shell Angola that was discussing reserves, not Shell Deepwater Services. That was not their remit." (Dep. pg. 62:18-63:21)

(b) "SDS were given the task to devise the most appropriate development scheme to evacuate the oil reserves, and as part of that process they would have taken into account various reserve volumes; a low, a most likely, and a high case. But the decision on what number is actually booked fell to Shell Angola in consultation with Remco and ultimately with Anton." (Dep. pg. 75:6-13)

(2) Hines

(a) "The way that Shell Deepwater Services was set up was to provide technical services to its customers. If Shell Angola had an asset and chose not to have its own resources to provide technical work, then Shell Deepwater Services could provide those services and support." (Dep. pg. 60:13-19)

(b) "We [at SDS] were not in a position to actually carry out full economics, because we didn't have legislative models, and so our interpretation of what was asked for here was that we would provide costing, phasing, scheduling information and estimations of volumes which could be used for their own economic evaluations. The economics, again governance over those decisions always rests with the Asset Team." (Dep. pg. 123:22-124:6)

(c) "SDS did not determine the quantity of proved reserves in Block 18 as reported in the ARPR process but provided technical information to enable SDAN to do so." (Decl. ¶ 13)

(d) "SDS was not tasked with estimating SDAN's proved reserves, because SDS did not complete the full economic and commercial analysis needed to estimate proved reserves. SDAN was responsible for and carried out these activities and to this end SDAN employed various economists including, latterly a woman named Liz Sturman. Thus, SDAN – not SDS – estimated its own proved reserves and reported those estimates to the Group Reserves Coordinator in The Hague." (Decl. ¶ 14)

c) The economics evaluations were the responsibility of SDAN.

(1) November 2, 2000 email from Ian Hines to Robert Inglis: "it would probably be best if we provide the costs and production profile data and let you run the economics." (WCK00010045-047)

(2) January 9, 2002 Email from D. Newberry (SDS) to W. Smits (SDAN): "As owner of the economics we felt it was appropriate that Liz [Sturman, an SDAN economist] completes this section, this will be completed tomorrow." (SMJ00038115-17)

(3) October 3, 2002 Email from W. Smits (SDAN) to I. Hines (SDS), discussing an upcoming meeting in Rijswijk: "The suggested purpose of the meeting is to discuss the Shell Angola business aspects and update [the Group Reserves Auditor] on the project's progress. Liz, I think we could nicely slot in the economics . . . which will leave us with a pure technical review/audit for the Houston meeting." (SMJ00039369-74)

7. SDS's technical assistance had the effect of reducing the quantity of proved reserves that SDAN reported.

(1) Hines

(a) "SDS's technical assistance in fact had the effect of reducing the quantity of proved reserves that SDAN otherwise hoped to report." (Decl. ¶ 20)

(2) Barendregt

(a) "SDS's technical work ultimately led to a decrease, rather than an increase, in the amount of reserves that SDAN reported as proved." (Decl. ¶ 21)

8. SDAN's proved reserves are ultimately irrelevant to the conduct test analysis.

a) Most of SDAN's restated reserves were reduced because they had been reported before Shell had reached a final investment decision about the project. As discussed above, project-maturity issues are economic issues, not related to the technical services that SDS provided.

(1) Proved Reserves Booking Lookback, June 2004: The reductions for 2000 and 2001 in SDAN resulted primarily from a lack of "project maturity." Proved Reserves Booking Lookback. (Doc. ID#600000000004867)

b) SDAN reported new proved reserves only twice during the Class Period and during SDS's existence: 75 million boe for year-end 2000 and an additional 46 million boe for year-end 2002. These additions amounted to only 0.39% of Shell's total reported proved reserves for 2000 and only 0.24% of Shell's total reported proved reserves for 2002.

(1) Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (RJW00082535-49); Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation (RJW00321825-37); Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (RJW01000022-37).

c) The additions also constituted only a trivial portion of the total amount of restated reserves: 0.00% for 1999, 1.55% for 2000, 0.00% for 2001, and 1.03 for 2002.

(1) Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation (V00081052-61); Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation (RJW00082535-49); Review of Group End-

2001 Proved Oil and Gas Reserves Summary Preparation (RJW00321825-37); Review of Group End-2002 Proved Oil and Gas Reserves Summary Preparation (RJW01000022-37).

F. <u>Responding to Allegations by Plaintiffs Regarding SDS's Involvement In Other Operating Units</u>

1. There is little evidentiary reason to detail SDS's work in relation to other operating units. The testimony, documents, and declarations in the record all consistently demonstrate that SDS's services to other operating units were unrelated to volumetric calculations, were provided to operating units that did not recategorize reserves and/or were unrelated to the reasons for the proved reserves recategorization. (*See e.g.*, for Morocco: Bichsel Dep. pg. 160:13-24, Sears Dep. pg. 79:25-80:5, Bichsel Decl. ¶13; for Egypt: Bichsel Dep. pg. 172:23-173:13, Sears Dep. pg. 78:21-24, Bichsel Decl. ¶14; for Kazakhstan: Platenkamp Dep. pg. 423:2-7; for Malaysia: Sears Dep. pg. 79:14-17, Bichsel Decl. ¶15; for Gabon: Bichsel Dep. pg. 213:13-19, Bichsel Decl. ¶ 32; for Indonesia: Sears Dep. pg. 81:11-15; for China: Sears Dep. pg. 83:11-21; for Trinidad: Sears Dep. pg. 80:24-81:3, Bichsel Decl. ¶ 36; for the Democratic Republic of the Congo and/or the Republic of the Congo: Sears Dep. pg. 74:15-18, Newberry Dep. pg. 21:12-23; Bichsel Decl. ¶ 37; The Philippines: Sears Dep. pg. 81:11-15, Bichsel Decl. ¶ 35; for Norway: Bichsel Decl. ¶ 31). Therefore, services provided by SDS to these other operating units are irrelevant to the fraud alleged by plaintiffs. However, for the sake of completeness, three operating units of seeming interest to plaintiffs are briefly addressed below. These operating units are Oman, Brazil and Brunei.

2. Oman

a) SDS had no involvement in Petroleum Development Oman ("PDO") related to restated reserves.

(1) Bichsel

(a) "I know for sure that we did not perform any services for PDO. PDO had no deepwater operations." (Dep. pg. 124:22-23)

b) SDS was involved in a deepwater project in Oman, but the relevant operating unit was not PDO. Furthermore, SDS was providing geological evaluation services and not assistance in the estimation of proved reserves.

(1) Sears

(a) "We were providing deepwater geological expertise in evaluation of frontier acreage offshore Oman in what we defined then as deepwaters, greater than 500 meeter [*sic*] water depths." (Dep. pg. 73:4-7)

(b) "Q. Do you recall whether SDS was asked to assist in the calculation of volumes in connection with the proved reserve reporting process? A. For a particular country? Q. Yes. Oman. . . . A. The answer is no, we were not." (Dep. pg. 73:11-16)

3. Brazil

a) Although SDS provided technical assistance that aided the Brazil deepwater operating unit in its efforts to estimate reservoir volumes, no proved reserves were reported for those fields during the class period.

(1) Bichsel

(a) "Q. At any point in time did Shell Deepwater Services consult with or interact with Brazil, the Brazilian OU, with respect to categorizing of proved reserves? A. When I was in Shell Deepwater Services the services that we provided [were] around exploration. We did not have any reserves found at that stage. We were exploring. When I was there we had some exploration successes that led to the discovery of scope for recovery volumes, but not to any reserves in the sense of proved reserves or expectation reserves." (Dep. pg. 131:6-20)

(b) "Q. I just want to make sure that we're clear. Do you have an understanding of whether Shell Brazil, and when I say Shell Brazil I'm talking about both deepwater, shallow water, onshore, any of those entities, did they ever request that SDS provide input with regard to volumetric determination of hydrocarbons? A. My recollection is that they did not." (Dep. pg. 188:14-24)

(2) Sears

(a) "Q. What was the nature of EDP's [the Evaluation and Development Planning division within SDS] involvement [in deepwater projects in Brazil]? A. Acreage evaluation, licenses that had recently been acquired, the identification of prospective drill sites, the planning of those wells, working with the well delivery unit to drill those wells, and in some cases evaluate and test. And then the follow-up, take the well data, incorporate it into our subsurface evaluation, and then continue the process. Q. What is acreage evaluation? A. Acreage evaluation is looking at the available geologic and geophysical data to understand what the earth looks like in a specific piece of geography." (Dep. pg. 76:23-77:13)

4. Brunei

a) The proved reserves restated for Brunei were associated with the operating unit called Brunei Shell Petroleum ("BSP"). BSP was primarily an onshore/shallow water operating unit and, with respect to deepwater, was responsible only for the Merpati-Meragi field. Proved reserves were restated for the Merpati-Meragi field.

(1) February 24, 2004 Davis Polk Telephone Interview with Yap Kong-Fah (Head of BSP Business Planning and Economics): "Merpati and Meragi are the only deep water fields in Brunei." (SCA00003126-34)

(2) SEC Proved Reserves Audit – Brunei Shell Petroleum SDN BHD, 29 Apr – 3 May 2002: "All of the fields [in BSP] are in relatively shallow offshore areas (up to 100 m water depth). Exploration focus is shifting towards deep offshore turbidite sequences, in which one field (Merpati) is carrying proved undeveloped reserves at this stage." (RJW01001253-68)

b) SDS provided limited technical services to BSP only in connection with the Merpati-Meragi field. The technical services provided were not related to the estimating or reporting of proved reserves.

(1) Kennett

(a) "During my employment at BSP [as Head of Reservoir Engineering and Chief Petroleum Engineer of Offshore West], I had some very limited correspondence with SDS regarding conceptual development options for the Merpati-Meragi field. . . . I did not ask SDS to assist me or anyone else at BSP in any way with the estimation or reporting of hydrocarbon reserves, and SDS did not provide any such assistance." (Decl. ¶¶ 24-25)

(b) "Q. Did SDS assist you . . . at all with respect to the booking of proved reserves? A. No. Q. How about the booking of expectation reserves? A. No. Q. How about the booking of legacy reserves? A. No. Q. Did you personally meet with anybody from Shell Deepwater Services? A. There was one occasion, . . . Mr. Richard Sears came over and gave a presentation . . . on deepwater. . . . Q. Did that presentation include a discussion of proved reserves? A. No. Q. Did that discussion include a discussion of expectation reserves? A. No. Q. Did that discussion include a discussion of marginal reserves? A. No. Q. Did that discussion contain a discussion of legacy reserves? A. No. Q. Can you think of any other instances in which you interacted with anybody from Shell Deepwater Services? A. No." (Dep. pg. 132:16-133:24)

(2) Sears

(a) "Q. Was SDS, in connection with Brunei, asked to calculate volumes of reserves in connection with this proved reserve reporting process that we've talked about? A. I do not believe so." (Dep. pg. 72:8-12)

c) SDS did not exist at the time BSP booked the restated proved reserves in Merpati and Meragi fields.

(1) The deepwater proved reserves that were restated for BSP were booked in 1992 for Merpati and in 1998 for Meragi, both prior to the formation of SDS in 1999. (Doc. ID#101331933)

(2) Bichsel

(a) "During my employment at SDS, I do not recall any technical assistance or advice that SDS provided to Brunei Shell Petroleum ('BSP') with respect to the categorization of proved reserves that were later restated." (Decl. ¶ 17)

d) There was also a deepwater operating unit in Brunei, Shell Deepwater Borneo ("SDB"). Although SDS did provide some technical assistance to SDB, the work never progressed because the operating unit was unable to get its license ratified.

(1) Bichsel

(a) "A. The relationship that SDS had with Shell Deepwater Brunei was in 1999, started in 1999. Q. And did that continue throughout your tenure at SDS? A. That did continue until the time, and I do not recall the date when it became clear, that because of certain issues between Malaysia and Brunei, a border dispute, . . . that the license was not, it was not possible to get that ratified. When that happened then effectively there was no need for any services to be provided by Shell Deepwater Services to Shell Deepwater Brunei." (Dep. pg. 190:8-23)

(2) October 13, 2000 Email from Matthias Bichsel to Richard Sears and Chandler Wilhelm regarding bid for new deepwater asset in the Brunei Exclusive Economic Zone ("EEZ"): "Due to potential conflict of interest in their shareholder relationship with the Government. . . BSP will not be allowed to bid." (Doc. ID#10000000026792)

(3) October 15, 2002 Email from Richard Sears to Bruce Buckley and Nick West: "Following on my visit to Brunei last month, attached is the first draft Strategic Contract between SDS and Shell Deepwater Borneo (SDB). SDB will operate the [deepwater] EEZ block." (Doc. ID#100000000216858)

TAB 8

FACT SUMMARY

VIII. SHELL EXPLORATION AND PRODUCTION TECHNOLOGY, APPLICATIONS AND RESEARCH

Plaintiffs also have tried to establish relevant U.S.-based conduct through the activities of Shell Exploration and Production Technology, Applications and Research ("SEPTAR"), another Shell service organization.

SEPTAR was Shell EP's research and development organization from July 1, 1999 until mid-2003. Most of SEPTAR's work involved creating, or purchasing from outside vendors, technology for subsurface exploration and production. SEPTAR then licensed or sold this technology to Shell operating units or unrelated companies in the marketplace. This work was unrelated to estimating or reporting proved reserves.

A small part of SEPTAR performed technical services for operating units, and a very small portion of that technical-services group was located in Houston. Plaintiffs' efforts to unearth U.S.-based conduct purportedly in furtherance of an alleged fraud have led plaintiffs to focus on these 40 Houston-based SEPTAR staff members within an organization of nearly 900 people.

This Houston group performed technical services – a minor component of SEPTAR's activities – primarily for EP's United States operating unit, SEPCo, but it also conducted a few field studies or other technical work for Shell operating units in Oman, Venezuela, and China. As discussed below, those technical services were insubstantial, were mostly incomplete or unsuccessful by 2004, and did not involve the estimating or reporting of proved reserves.

A. SEPTAR's Formation and Organization

Until July 1, 1999, Shell researched and developed technology in two independent laboratories. One laboratory was called Research and Technical Services ("RTS") and was located in Rijswijk, the Netherlands. The other laboratory was located within the Bellaire Technology Center ("Bellaire") in Houston, Texas.

Shell combined these two laboratories on July 1, 1999 to avoid duplicative research and development expenses. The laboratories did not change personnel or physical locations; they simply changed their names to SEPTAR.

SEPTAR was part of Shell EP's Technology division ("EPT"). EPT's leadership was based in Rijswijk. Although SEPTAR itself had staff in both Rijswijk and Houston, Rijswijk was the "nerve center" of the organization. The majority of SEPTAR's staff was based in Rijswijk,[86] and SEPTAR's leadership was in Rijswijk as well.[87]

SEPTAR was organized into five clusters when it first formed. As depicted below, those clusters were: Shared Earth Model ("SEM"), Wells, Novel Technology, Surface, and Geosciences and Integrated Services ("GIS").

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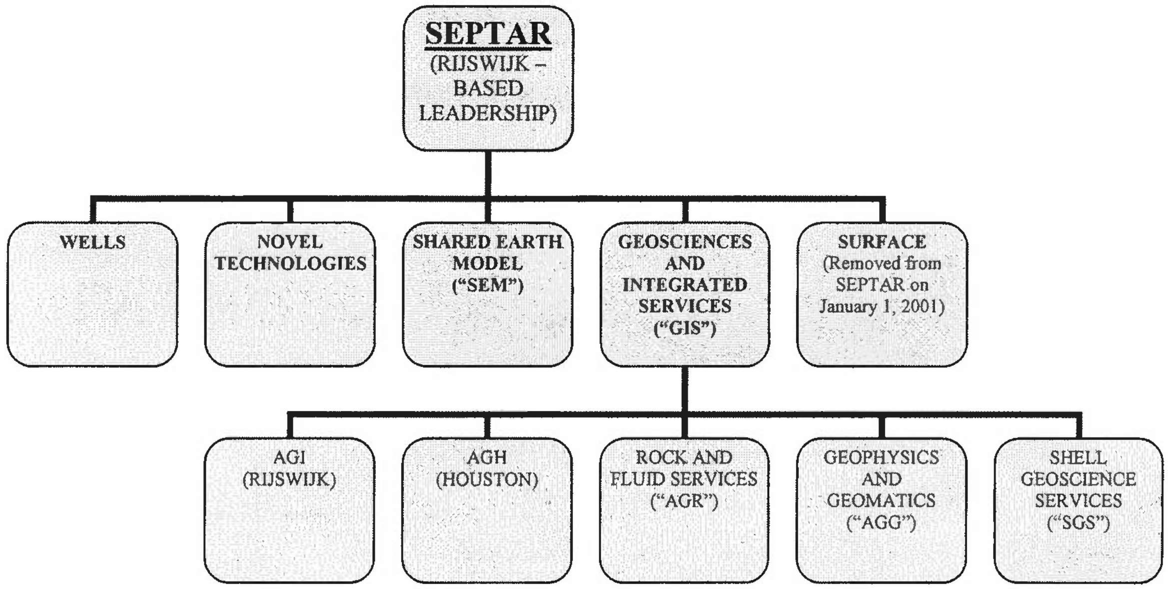
86 *See* SEPTAR Business Plan 2000, vol. 2 (Doc. #103832193).

87 Percival Decl. ¶ 11; Henderson Decl. ¶ 7.



1. **<u>The Research and Development Clusters</u>**

Three of the five clusters – SEM, Wells, and Novel Technology – focused on research and development of technology, both hardware and software.[88] That work did not involve estimating or reporting proved reserves and thus has no relevance to this case. Most of the technology was being developed for commercialization or to help operating units explore for new oil fields long after the end of the Class Period.[89] While several other forms of technology (underbalanced and expandable well-drilling hardware) were used during the Class Period, they were used infrequently on only a few fields; they affected only daily production rates, and they were not used to estimate proved reserves.

To the extent those three clusters licensed or sold third parties' technology to Shell operating units, the operating units used those products at their own discretion and under

88 Henderson Decl. ¶ 8.

89 *See* Jan. 31, 2000 ExCom Note for Information (Doc. #100196618); Hoffman Dep. at 19:20-20:12.

the direction of the operating-unit staff. SEPTAR merely played the role of a middleman.[90] Moreover, there is no evidence that any technology product that SEPTAR licensed or sold to an operating unit was used to estimate or report proved reserves.

2. **The Surface and GIS Clusters**

SEPTAR's two remaining clusters, Surface and GIS, did not conduct research or procure technology. Instead, they engaged in SEPTAR's secondary role of providing technical services to operating units.

The Surface cluster was removed from SEPTAR on January 1, 2001, because every other SEPTAR cluster was focused on the *sub*surface, and Surface's work therefore did not seem to fit within SEPTAR's mission. The Surface cluster never performed technical services related to estimating or reporting proved reserves. After 2000, only about one-quarter of SEPTAR's staff performed technical services, and almost all of those persons were within the GIS cluster.

The GIS cluster had between 200 and 300 staff members between 1999 and 2003. As shown on the chart, GIS consisted of five sub-clusters, which performed specialized services for operating units to better understand the subsurface. Three of those sub-clusters had staff in both Rijswijk and Houston:

- The Rock and Fluid Services sub-cluster ("AGR") analyzed the composition of subsurface rocks.
- The Geophysics and Geomatics sub-cluster ("AGG") collated spatial data about the subsurface from different sources.

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[90] The liaison between the operating unit and SEM to acquire these technology products was called a Business Interface Manager ("BIM"). The BIM group was based in Rijswijk. *See* BIM Team Presentation (Doc. #106435830).

- The Shell Geoscience Services sub-cluster ("SGS") assisted in processing seismic data. (SGS was moved out of GIS and into the SEM cluster in 2003, because SGS's work related to the seismic processing software that SEM was developing.)

On rare occasions, these three sub-clusters performed discrete studies to help operating units understand the physical properties of unusual subsurface compositions. But there is no evidence that these sub-clusters' services involved estimating or reporting proved reserves.

The two remaining GIS sub-clusters – Integrated Regional, Acreage and Field Development Services ("AGI") and Field Studies-Houston ("AGH") – focused on field studies. AGI had staff only in Rijswijk. AGH's staff was located almost entirely in Houston (except for four senior engineers based in Rijswijk).[91]

AGI, the Rijswijk-based unit, was the dominant sub-cluster within GIS. AGI accounted for most of GIS's revenue and employed more than 140 of GIS's 200 to 300 staff members in 2002. AGH, the Houston-based sub-cluster, had only about 40 staff members in 2002 and was one of GIS's smallest sub-clusters.[92] Because of its sheer size and large resource base, AGI was able to provide more extensive services for operating units than was AGH.

AGH was the only U.S.-based sub-cluster that performed field studies for Shell operating units whose reserves were recategorized. AGI's work bears no possible relevance to any examination of U.S.-based conduct, because the Rijswijk-based AGI had no connection to the United States.

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91 Percival Decl. ¶ 12; Henderson Decl. ¶ 9.

92 *See* GIS Staff Plan (Doc. #200000005990472).

B. **Irrelevance of AGH's Work**

AGH performed field studies or other technical work for three operating units in Oman, Venezuela, and China whose proved reserves were recategorized. In none of these cases, however, did AGH's work involve estimating or reporting the operating units' proved reserves.[93]

1. **AGH's Studies in Oman**

Between late 2001 and 2003, AGH performed field studies on a small number of fields run by Petroleum Development Oman ("PDO") to assess the feasibility of experimental hydrocarbon recovery techniques. The studies emerged from a PDO initiative called "T50," which aimed to increase PDO's rate of hydrocarbon recovery by 2030.

Pursuant to this initiative, PDO paid AGH to perform enhanced oil recovery ("EOR") feasibility studies on a few fields. PDO engaged AGH because the AGH staff members had considerable experience applying EOR techniques in the United States in the 1980s. Before the "T50" initiative, only AGI, in Rijswijk, had provided technical services to PDO.

AGH's EOR feasibility studies did not estimate PDO's proved reserves. EOR is a technique for injecting chemicals or heated substances into a field with the hope of increasing hydrocarbon recovery. These studies were simply pilot studies to determine whether employing a particular EOR technique was technically feasible on a specific PDO field. Determining a particular technique's feasibility does not involve estimating proved reserves.[94]

AGH's EOR feasibility studies also played an insignificant role in PDO's own field-development planning. Many variables can affect the success of a particular EOR technique. One of the most important variables is the economic analysis of the technique,

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93 Percival Decl. ¶ 30.

94 Henderson Decl. ¶¶ 23-24.

because EOR costs considerably more than does conventional recovery. Operating units do not even contemplate using EOR when oil prices are low, because EOR can be so expensive. AGH did not have any economists and never performed any economic analysis during its field studies. Thus, the operating unit, not AGH, had to decide whether to develop a field by using EOR, and the operating unit could not make that decision until after it had carefully analyzed all the competing economic costs and benefits.[95]

Moreover, successful EOR technical feasibility studies take years to complete, and there is no evidence that AGH's EOR studies were used to book proved reserves for PDO during the Class Period. AGH did not even begin most of the EOR studies for PDO until 2002, and almost all of them were still ongoing through 2004.[96] The economic landscape can change considerably over the duration of a multi-year EOR technical-feasibility study, making AGH's role in PDO's field-development planning during the Class Period even more insignificant to any estimating of proved reserves at PDO.

2. **<u>AGH's Studies in Venezuela</u>**

AGH performed field studies for only two projects for Shell Venezuela S.A. ("SVSA"). These studies created reservoir-simulation models, which are predictive maps of the subsurface of a hydrocarbon field or reservoir, based on data collected at the site of the field or reservoir. Reservoir-simulation models do not estimate proved reserves.[97] In addition, Venezuela's reserves were recategorized for lack of project maturity and for failure to use the

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95 Henderson Decl. ¶ 25.

96 Percival Decl. ¶ 27.

97 Henderson Decl. ¶ 21.

correct year-end pricing.[98] Neither of those issues related to any technical services that AGH might have rendered to SVSA.

3. **AGH's Work in China**

AGH also performed certain technical services for Shell Exploration China Ltd. ("SECL"), but AGH never estimated SECL's proved reserves.[99] Moreover, SECL's proved reserves were restated because SECL had used Shell's internal project-screening values, rather than year-end pricing, to calculate its proved-reserves entitlements.[100] This issue does not relate to any technical work performed by AGH. In addition, the SECL restatement was only a trivial amount: the restatement for 2002 constituted just 0.001 bboe, or 0.022% of the 4.47 bboe restatement that Shell announced in its 2004 Form 20-F.[101]

C. **Irrelevance of AGI's Work**

Any studies performed by AGI are irrelevant to the conduct test, because AGI was based in Rijswijk and had no connection to the United States. Although both AGI and AGH were sub-clusters within the same cluster (GIS) of SEPTAR's five clusters, AGI staff and Houston-based AGH staff did not work together on field studies.[102]

AGH and AGI generally did not perform field studies even for the same operating units. AGI did work for operating units in Africa, the Middle East, and Europe, and AGH

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98 Cooper Decl. ¶ 74; Doc. #600000000004867.

99 Barendregt Decl. ¶ 18; Percival Decl. ¶ 30.

100 Barendregt Decl. ¶ 18; Cooper Decl. ¶ 49; Doc. #600000000004867.

101 Cooper Decl. ¶ 49 and accompanying table.

102 Percival Decl. ¶¶ 17, 20. One Houston-based AGH staff member was sent to AGI to work on a project in Kuwait with an AGI team. However, this AGH staff member was effectively seconded to AGI, and no work on that project was done in Houston. *See* Henderson Decl. ¶ 10.

performed studies for operating units in the United States, South America, and Asia. Oman was an exception: both AGI and AGH performed field studies for PDO. But even the PDO field studies were separated, so that AGH and AGI did not work together. Plaintiffs thus cannot attribute AGI's work to AGH in any attempt to show U.S.-based conduct.

Nor do the technical services that GIS provided to Shell Petroleum Development Company ("SPDC"), in Nigeria, have any connection to the United States. Only AGI performed technical services for SPDC, which was by far AGI's largest operating-unit client. AGI even created an SPDC "seamless team" with approximately 60 AGI staff members, every one of whom was based in Rijswijk. AGH had nothing to do with AGI's work for SPDC.[103]

D. **<u>SEPTAR's Disbanding in 2003</u>**

In 2003, Shell leadership determined that SEPTAR was not meeting its goals. Some operating-unit staff members found SEPTAR's organization confusing because of the numerous internal reorganizations, which had been preceded by reorganizations within Research and Technical Services (in Rijswijk) before SEPTAR was formed. Shell also saw inefficiencies in SEPTAR's dual role of performing services as well as research and development. By mid-2003, SEPTAR's organizational structure began to change, and by January 1, 2004, SEPTAR ceased to exist. The research clusters within SEPTAR became EPT Research, and GIS combined with some of parts of Shell Deepwater Services to form EPT Solutions.

103 Percival Decl. ¶ 21; Okon Decl. ¶ 6; Percival Dep. at 150:21-25.

FACT SUPPORT

VIII. SHELL EXPLORATION AND PRODUCTION TECHNOLOGY, APPLICATIONS AND RESEARCH

A. Background

1. Shell Exploration and Production Technology, Applications and Research ("SEPTAR") was an organization within the Exploration and Production ("EP") business of the Royal Dutch/Shell Group of Companies ("Shell" or "the Group"). SEPTAR was created by the July 1, 1999 combination of two previously independent research laboratories in the Netherlands and the United States. It was located in EP's Technology division ("EPT").

   a) *See* Henderson Decl. ¶ 7.

   b) *See* Percival Decl. ¶ 8.

   c) November 28, 2002 GIS-EDP comparison: "[SEPTAR] formed in 1999, when EP Research and Technical Services (RTS) combined with BTC." (Doc. ID#104293158)

2. Prior to July 1, 1999, the Netherlands research laboratory was called Research and Technical Services ("RTS") and it was located in Rijswijk.

   a) *See* Henderson Decl. ¶ 7.

   b) *See* Percival Decl. ¶ 8.

3. Prior to July 1, 1999, the United States research laboratory was located at the Bellaire Technology Center ("BTC") in Houston, Texas. It conducted services exclusively for Shell Oil, Inc., a Shell subsidiary based in the United States.

   a) Henderson

      (1) "[B]efore July of 1999, the research lab in Bellaire, a subsidiary of Houston, a suburb of Houston, worked only for Shell Oil U.S., and the Rijswijk lab supported the rest of the world." (Dep. pg. 53:18-21)

   b) *See* Henderson Decl. ¶ 7.

   c) *See* Percival Decl. ¶ 8.

4. SEPTAR was EP's research and development organization.

   a) SEPTAR was formed as a cost-saving device to avoid duplicative investment in research and development of new technologies.

      (1) Warren

         (a) "As I say, the objective of bringing the two centers closer together was to remove duplication, increase effectiveness, increase efficiency . . . ." (Dep. pg. 47:4-5)

   b) SEPTAR's primary focus was on the research and development of technology products which were not developed for any specific operating unit. A secondary role of SEPTAR was providing technical services to specific operating units.

      (1) Hoffman

         (a) "The core business [of SEPTAR] is R&D . . . ." (Dep. pg. 27:14-15)

      (2) Percival

         (a) "SEPTAR was primarily a research and development organization focused on technology applicable to exploration and production." (Decl. ¶ 9)

      (3) September 15, 1999 DRAFT Mission and Strategy for SEPTAR notes SEPTAR's mission is "to provide technology to the EP Sector of Royal Dutch Shell . . . ." (Doc. ID#0100000000978707)

5. The leadership of SEPTAR was located in Rijswijk.

   a) Paul Sullivan, the director of SEPTAR, was located in Rijswijk:

      (1) Darley

         (a) "Q. You identified Paul Sullivan as the individual who's the head of SEPTAR . . . . A. That's right." (Dep. pgs. 183:22-184:2)

         (b) "In 2001 Paul Sullivan had his office in Rijswijk, so he was looking after the activities of SEPTAR in Rijswijk." (Dep. pg. 123:21-24)

b) The other top officials of SEPTAR were also located in Rijswijk.

(1) Percival

(a) "I reported to SEPTAR's director, Paul Sullivan, who worked in Rijswijk, as did SEPTAR's other top officials." (Decl. ¶ 11)

(2) *See* Henderson Decl. ¶ 11.

c) SEPTAR was part of EPT, whose leaders, John Darley and Tim Warren, were based in Rijswijk.[1]

(1) Darley

(a) "Q. Your offices were maintained in Rijswijk at that time? A. Rijswijk, yes. Q. Was that true throughout your tenure at EPT? A. Yes." (Dep. pg. 51:17-22)

(2) Warren

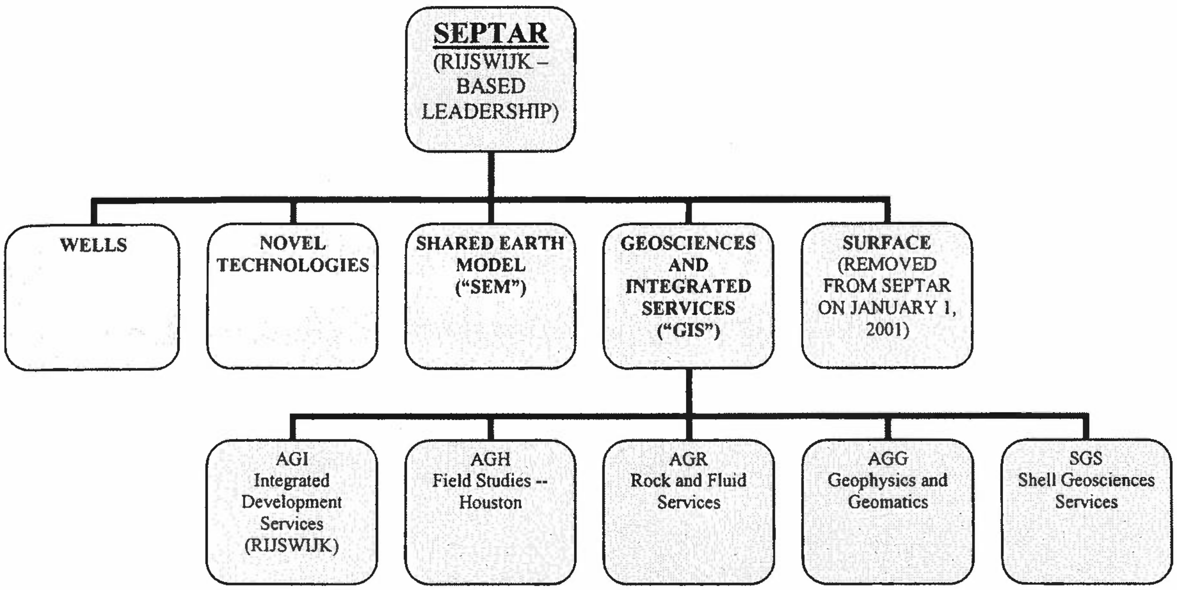
(a) "Q: When you left your position as the [director of EPT], where did you go? A. I stayed in The Hague." (Decl. pg. 53:10-14)

(3) January 29, 2003 Overview E & P, STEP & SEPTAR shows where SEPTAR fit within EPT. (Doc. ID#108027977)

[1] EPT was also known as Shell Technology Exploration & Production ("STEP").

B. SEPTAR's Organizational Structure

1. SEPTAR was organized by "clusters." The following chart depicts the organizational structure of SEPTAR prior to 2001.



a) SEPTAR comprised five clusters: Wells, Geosciences and Integrated Services ("GIS"), Surface, Shared Earth Model ("SEM"), and Novel Technologies.

(1) August, 29, 1999 SEPTAR Business Plan 2000 Volume 2 shows the staffing numbers of the various SEPTAR clusters and groups. (Doc. ID#103832193)

(2) *See* Percival Decl. ¶ 9.

(3) *See* Henderson Decl. ¶ 8.

b) The five clusters had staff in both a Houston branch and a Rijswijk branch.

(1) Darley

(a) "The offices of SEPTAR were divided . . . between Rijswijk in the Netherlands, and Bellaire Technology Center in Houston." (Decl. pg. 10:19-22)

(2) Hoffman

(a) "Were there other clusters [besides SEM] operating in Houston? A Yes. . . . [T]he model was that all the clusters . . . had people in Houston and in Rijswijk." (Decl. pg. 24:2-12)

c) The SEM, Wells and Novel Technology clusters conducted primarily research and development. These clusters accounted for a majority of SEPTAR's staff.

(1) *See* Henderson Decl. ¶ 8.

(2) *See* Percival Decl. ¶ 9.

(3) January 30, 2001 Update 2000 SEPTAR Establishment shows that over half of SEPTAR's staff were part of these three clusters as of April 2000. (Doc. ID#103847285)

d) The GIS cluster performed subsurface technical services.

(1) *See* Henderson Decl. ¶ 8.

(2) *See* Percival Decl. ¶ 9.

e) The Surface cluster performed engineering services related to surface facilities. This cluster was removed from SEPTAR at the beginning of 2001.

(1) Darley

(a) "[U]ntil January 2001 there was a group in SEPTAR which was called the surface cluster, which dealt with surface engineering, that being pipelines . . . separator facilities, gathering facilities, so on, engineering work, if you like." (Dep. pg. 174:17-24)

f) SEPTAR also had a Value Assurance Services ("VAS") group, which was located entirely in Rijswijk.

(1) Percival

(a) "There was a Value Assurance Services group located entirely in Rijswijk within SEPTAR." (Decl. ¶ 10)

(2) January 30, 2001 Update 2000 SEPTAR Establishment shows that all 15 VAS members were located in the Netherlands. (Doc. ID#103847285)

C. SEPTAR's Formation and Subsequent Reorganizations

1. There is no evidence that SEPTAR actually functioned as an integrated global technical service provider.

a) The SEPTAR integration theme was a slogan used to describe how Shell management wanted the organization viewed from the outside, not how it functioned internally with respect to the provision of technical services.

(1) Henderson

(a) "A. 'One Stop Shop' I think meant that the customers could come to one person, who could then get their request or work to the right party to execute the work. Q. To a person, not a group? A. Yes. Q. Do you know if this happened . . . ? A. I don't think it happened at all . . . . This whole thing was not done by leadership . . . [Y]oung employees . . . generated this framework . . . but much of it actually didn't get executed." (Dep. pg. 59:8-24)

(2) Warren

(a) "Q. So when it says unified global E&P technology organization with two hubs, [SEPTAR] was one organization with two centers; is that correct? A. As I said this morning, it was two separate corporate organizations. Those were the two hubs. They had a similar identical internal geometry which I've been calling the mirror image and they cooperated and collaborated in a manner that reduced duplication and maximized cost effectiveness and efficiency. Q. Why did you call it a unified global organization? A. Again, you're talking to an external audience who does not want to be bothered with the internal complexities of your corporate organization." (Dep. pgs. 122:18-123:13)

(3) September 21, 2003 Shell EP Technology: From SEPTAR to EP R&D notes that SEPTAR is being reorganized because it has a "fragmented" strategy, a "silo mentality," is a "big and very mixed" organization, has an inefficient technology portfolio and is being redesigned for "better focus." (Doc. ID#0100000000950964)

(4) November 17, 2000 Technical Leadership Team Action Items notes that Shell and operating unit personnel do not "trust" the Houston office of SEPTAR for technical services and it is critically affecting integration. (Doc. ID#104102567)

b) In reality, the SEPTAR offices provided technical services to different operating units based on their geographic proximity to Houston or Rijswijk.

(1) Darley:

(a) "Yes . . . I explained earlier . . . that much of the work was directed geographically, so the work for SPDC Nigeria was done in Rijswijk . . . the work for PDO in Oman was done in Rijswijk." (Dep. pg. 65:20-25)

c) The operating units dealt directly with either the Rijswijk laboratory or the Houston laboratory prior to the formation of SEPTAR and that did not change significantly after SEPTAR was formed.

(1) Henderson

(a) "Q. Why wasn't [GIS] a 'One Stop Shop'? A. Because we kept doing business the way we had done before. Q. And how was that? A. People who knew us kept coming directly to us instead of going through a central parsing person . . . ." (Dep. pg. 60:9-15)

d) The integration image was also thwarted by the complicated organizational structure and names within SEPTAR.

(1) Malcolm

(a) "Q. Do you recall during the period of 2002 until 2004 SEPTAR . . . performed any work at PDO? A. The names of what I would refer to as EPT, the EP Technology Center, have many names. SEPTAR is one of the names I recognize, but some of those names change so fast for me that I'm not always -- but I think SEPTAR stood for Shell EP Technology and Research, but I cannot even remember what it stood for . . . ." (Dep. pgs. 59:17-60:3)

(2) October 1, 1999 Email string from I. Percival to F. Hoffman, where J. Chapman writes: ". . . SIPM, SIEP, RTS, SEPTAR and whatever they call themselves next year . . . ." (Doc. ID#103840324)

2. The multiple reorganizations of SEPTAR during its short-lived existence, 1999 through 2003, evidence Shell's recognition that SEPTAR in Rijswijk and in Houston did not operate as an integrated technical service provider.

a) Two service clusters at SEPTAR were removed through independent reorganizations before SEPTAR was entirely disbanded near the end of 2003.

(1) In 2001, just two years after SEPTAR was formed, the Surface cluster was moved into another Shell EP organization called Shell Global Solutions.

(a) Darley

(i) "[I]n January of that year [the Surface cluster] was taken out of SEPTAR and moved into Shell Global Solutions." (Dep. pgs. 174:24-175:3)

(2) The Value Assurance Services group was also removed from SEPTAR in 2002.

(a) Darley

(i) "[W]e formed a new organizational unit comprising the value assurance review groups. I don't remember the exact date of that formation." (Dep. pg. 73:22-24)

(ii) "When [Technical and Operational Excellence] was formed in 2002, it took . . . the value assurance groups and it moved them under one of my colleagues, Brian Ward, who was then leader of that organization." (Dep. pg. 206:2-9)

b) SEPTAR itself was disbanded in late 2003 for the express purpose of creating a more efficient group of research and development and technical services entities.

(1) SEPTAR disbanded and combined with other organizations to form EPT Solutions (sometimes referred to as EP Solutions), and EPT Research (sometimes referred to as EP

Research or EP R&D). The effective date establishing EPT Solutions was January 1, 2004, but the organizational changes occurred earlier in mid-2003.

(a) Percival

(i) "After a couple of years, there was a workshop on, is STEP still . . . efficient, is it fulfilling the role that had been asked of it to deliver in July of 1999? And the conclusion was drawn that there was a degree of . . . overlap. And to me it seemed most efficient and effective use of the individual resource, it was almost certainly better to have one subsurface group called EP Solutions, and that's indeed what we did." (Dep. pg. 22:16-24)

(b) Henderson

(i) "A. The reorganization that happened in either late 2003 or early 2004 combined all the service components of the EPT into a new mix of groups, so [Shell Deepwater Services] went away, GIS went away, SEM went away, and new entities were formed . . . . Q. Is that EPT Solutions, if you know? A. [Yes]." (Dep. pgs. 76:21-77:3)

(ii) "SEPTAR had a relatively short-lived existence and did not achieve all the aspirations that its leadership had envisioned. For example, the GIS cluster did not meet the goal of interacting with the Shared Earth Model cluster to help implement and develop technology on a global scale. Rather, SEPTAR was an organization with disjointed clusters and sub-clusters that performed well within their respective capabilities but that did not interact with one another to create the hoped-for efficiencies. Consequently, in 2003, Shell's Exploration and Production Technology unit began to implement organizational changes that affected, and ultimately disbanded, SEPTAR. Although these changes did not officially take place until January 1, 2004, the organizational changes actually began occurring by mid-2003." (Decl. ¶¶ 26-27)

(c) Darley

(i) "SEPTAR . . . in 2001 was something of a conglomerate of activities comprising both the research and development as well as the study groups as well as oil engineering capability. The proposal here was to streamline and align those capabilities so that research and development would be separated from study activity. (Dep. pg. 309:17-25)

(ii) "[T]he main change into EPT Solutions was to take out from SEPTAR the study groups, but the division between Houston and Rijswijk largely remained as it had been earlier." (Dep. pgs. 67:24-68:5)

(iii) "[W]e then had a group which was the R&D organization in EPT which was no longer called SEPTAR, it was EP R&D." (Dep. pgs. 66:25-67:3)

(d) December 16, 2002 STEP Direction in 2003 describes the reorganization of SEPTAR and SDS. (Doc. ID#100164747)

D. SEPTAR's Shared Earth Model Cluster — The Research and Development Cluster

1. As stated above in Section A.4.b), SEPTAR's primary focus was on the research and development of technology. This research and development function was discharged largely by the Shared Earth Model cluster ("SEM"). SEM created and deployed exploration and production technology which was intended for general application within Shell or by third-party purchasers. SEM, as well as the other research and development clusters of SEPTAR, created and deployed hardware and software technology associated with the subsurface, and it also deployed technology produced by third-party vendors. Technology deployment was coordinated by the Business Interface Management Group ("BIM"), which was based in Rijswijk. There is no evidence any of these technology products were used to estimate or report proved reserves.

a) Hoffman

(1) "I was Vice President in the R&D organization called SEPTAR . . . . I handled a specific set of technologies. I was Vice President of Shared Earth Model, so those are technologies associated with the subsurface; in particular, geophysics, geology, petrophysics and some computer science." (Dep. pg. 11:8-16)

b) Darley

(1) "Q. The technologies that were under consideration for deployment at PDO, were those technologies developed by SEPTAR? A. Not uniquely. There may also be third party technologies." (Dep. pg. 252:17-22)

c) November 2001 BIM Team Presentation, explains how BIM, led by Dan Antheunis in Rijswijk, coordinated technology deployment between the SEPTAR research and development clusters and the operating units. (Doc. ID#106435830)

2. SEM's research and development products were generally hardware used in wells, or software and database compilations to be used by operating units to explore for new oil fields in the future. Identifying a brand new accumulation of hydrocarbons does not involve the estimation or reporting of proved reserves.

a) Hoffman

(1) "[L]et me talk about what kinds of things we deploy . . . . When we do R&D, many times what we deliver is a software product --and sometimes a database where we would compile data from around the world, so those are two main vehicles for delivering the end result of R&D . . . . [S]oftware sometimes gets delivered in stages, and so we would have an end goal in mind, but we would sometimes try to deliver intermediate products on our way to final products . . . ." (Dep. pgs. 49:21-50:9)

(2) "A. [T]hese technologies were really focused on . . . finding brand new oil fields that no one else had ever been able to see before . . . . Q. Did Shell apply these technologies on existing oil fields? A. Generally not." (Dep. pgs. 19:20-20:12)

b) SEPTAR 2002 EP Business Appraisal describes SEPTAR's hardware technology for wells, such as expandable tubes, corrosion resistant alloy wells casing clads, and "swell-able elastomers." (Doc ID#0100000000164859)

3. The technology developed by SEPTAR was not necessarily used by Shell, nor was it necessarily created entirely by SEPTAR. The technology developed by SEPTAR was sometimes developed through joint ventures with third party firms such as Halliburton and Schlumberger. It was also sold in the marketplace to third parties.

a) January 31, 2000 ExCom Note for Information describes the various technology development joint ventures between SEPTAR and third parties, as well as the general strategy to commercialize and sell the technology in the open market. (Doc. ID#100196618)

E. <u>SEPTAR's Geosciences and Integrated Services Cluster</u>

1. As stated above in Section A.4.b), SEPTAR's primary focus was on the research and development of technology which was not intended for any particular operating unit.

2. A secondary role of SEPTAR was providing technical services to specific operating units, which was accomplished predominately through the Geosciences and Integrated Services ("GIS") cluster.

3. The GIS cluster consisted of numerous sub-clusters, such as Rock and Fluid Services (AGR), Geophysics and Geomatics (AGG), Shell Geosciences Services (SGS), Field Studies – Houston (AGH), and Integrated Development Services (AGI), based in Rijswijk.

a) AGR, AGG and SGS performed highly specialized services to determine the composition of unusual subsurface geological formations, and there is no evidence they performed services that estimated or reported proved reserves.

(1) Percival:

(a) "[T]he CORES Team (AGR) within GIS cannot do reserve estimation themselves. It's just not in the rules of . . . their business." (Dep. pg. 123:11-13)

(b) "GIS itself consisted of multiple sub-clusters. Many of the sub-clusters were staffed with specialists in highly technical fields, such as geophysics, geomatics, reservoir engineering and petrophysics." (Decl. ¶ 12)

(c) November 28, 2002 GIS-EDP comparison summarizes the "Advanced Technical Services" offered by the GIS sub-clusters. (Doc. ID#104293158)

F. Introduction to AGH and AGI

1. AGH and AGI, which have been the focus of this litigation, performed technical services to support an operating unit's field team during a field study.

a) AGH was located almost entirely in Houston, and AGI was located entirely in Rijswijk (and in Aberdeen as well from 2002 onwards).

(1) Henderson

(a) "I managed the AGH sub-cluster, which was located almost entirely in Houston. However, AGH also had four senior engineers in Rijswijk who were specialists in pressure testing and reservoir simulations." (Decl. ¶ 9)

(2) Percival

(a) "AGI's staff was located initially in Rijswijk, and in 2002 onwards in Aberdeen as well." (Decl. ¶ 12)

b) Operating units generally performed their own technical services and rarely called upon AGI or AGH to conduct these services.

(1) Darley

(a) "Many operating units undertook those exercises themselves. They had the necessary capability, they had the necessary strength and expertise. In some parts of the organization, there were more fields discovered and more opportunities than the local operating unit had capability or capacity to handle, and those studies were then requested from SEPTAR." (Dep. pg. 15:14-25)

(2) Henderson

(a) "Staff members at Shell operating units generally performed their own field studies and technical services. However, on rare occasions, an operating unit would contact AGH to perform highly technical studies when the operating unit's own staff lacked certain specialized expertise. AGH was not always able to accommodate such requests, but we would assist if AGH had the necessary expertise and staff availability." (Decl. ¶ 12)

2. If AGI or AGH were asked to perform the occasional service for a non-U.S. operating unit, many aspects of the work were physically done at the site of the operating unit.

a) Henderson

(1) "[W]e basically had a customer service company relationship, so we would go to meet with our customers in whatever physical location they were in, as long as it was a place we could travel to." (Dep. pg. 72:6-10)

(2) "The operating unit's staff always would lead the field study, and sometimes outside consultants would be hired to assist, depending on the particular expertise required." (Decl. ¶ 13)

b) Darley

(1) "The work that would be done in Oman would be typically hands-on kind of work, so going to the field to identify opportunities to change the setup of the production system, or to assess the opportunity to optimize flow through the pipelines and flow line systems which typically will require data to be gathered in the field and advice to be given to staff in the field. In those instances clearly SEPTAR staff would go to Oman. The work that was done in Rijswijk and in Houston would be study work where the data would be provided, and that would be subsurface data, geological data, for example, which would then be interpreted in the study teams and the results of that work would then be communicated to the operator." (Dep. pgs. 247:2-248:22)

3. The operating units would specify the services they wished to assign to AGI or AGH and the operating units would pay for the services.

a) Darley

(1) "Don't forget this work is always done on behalf of the operator . . . . SEPTAR is not of themselves deciding which studies to do." (Dep. pgs. 248:22-249:4)

(2) "A. [T]he operating unit would agree that the study would be done and it would cost so much and it would take so long and these would be the resources that would be assigned to do that work. Q. Am I correct that the

OUs . . . paid SEPTAR for the study work that they performed in their behalf? A. Yes . . . ." (Dep. pgs. 17:16-18:2)

G. AGI's Technical Services Cannot be Attributed to AGH

1. The work done by AGI staff based in Rijswijk cannot be attributed to AGH staff based in Houston. Houston-based AGH members and AGI almost never worked together to provide services to operating units. There was only a single occasion where a Houston-based AGH member worked with AGI, which involved a potential project in Kuwait which did not come to fruition.

a) Henderson

(1) "To the best of my recollection, there was only one occasion where a Houston-based AGH member worked with AGI. On this occasion, one AGH member was sent to Rijswijk to work with AGI on a potential project in Kuwait. This member was informally 'seconded' to AGI and the AGI sub-cluster leaders oversaw all aspects of his work. In the end, the project did not come to fruition." (Decl. ¶ 10)

(2) "Q. And in 2001 did you consult with AGI on various projects? A. No. They ran projects out of AGI in Rijswijk, and I ran projects out of AGH in Houston. Q. Did they consult with you on projects that they were running? . . . A. We worked independently." (Dep. pgs. 34:12-35:3)

(3) "I don't recall any work being done that I would have considered in virtual teams." (Dep. pg. 153:12-13)

b) Percival

(1) "If I roll back to July of '99 when [SEPTAR] was put up, there was a desire to create . . . a fluid global organization working in global teams using IT. That was a great dream, but the practicalities became clear after a matter of months that just because of time zone difference . . . . It made a lot of sense to say, okay, a team in Rijswijk or Aberdeen will do such-and-such work, the team in Houston will do work." (Dep. pg. 25:3-12)

(2) "GIS's field services were 'ring-fenced,' so AGH staff (in Houston) and AGI staff (in Rijswijk) did not work together. This division of labor predated SEPTAR's formation." (Decl. ¶ 17)

c) *See* Percival Decl. ¶¶ 18-20.

d) Darley

(1) "A [SEPTAR team] that was looking at a given reservoir development plan would usually be comprised of individuals in one location. Those study teams were not usually split." (Dep. pg. 65:6-10)

e) November 28, 2002 GIS-EDP Comparison: "Each GIS team works . . . separately and has [its] own customer base in the OUs, although both AGH and AGI have worked with PDO over the last year." (Doc. ID#104293158)

H. <u>General Nature of AGH's Technical Services</u>

1. AGH, based in Houston, performed services primarily for EP's operating unit in the United States, Shell Exploration and Production Company ("SEPCo").

a) Warren

(1) "The technical services offered by the U.S. SEPTAR were designed to be those that were required by the Shell operations here in the U.S. and specifically to satisfy the majority of, if I could use another anagram, SEP's needs, Shell E&P Company, here in the States, who would be the primary customer for SEPTAR in the States." (Dep. pg. 50:15-22)

2. AGH's primary technical services involved generating simulation models. These models provide a map of the subsurface.

a) Henderson

(1) "AGH's primary technical service involved the completion of a study and report on a hydrocarbon field's subsurface characteristics. Operating units contacted us only when a particular field was technically challenging. We would go to an operating unit's office to gather data and predict the characteristics of the subsurface and create a map of the subsurface – a reservoir simulation model. On some occasions, AGH would simply map the subsurface. On other occasions, AGH would try to predict how the subsurface would perform if the operating unit used a particular development technique. For example, AGH created waterflood reservoir simulation models to predict how flooding an oil field would alter the subsurface oil

distribution. We then gave our models to the operating units, which could use them to weigh potential development options or simply for comparison with reservoir models that the operating units themselves had created in the past." (Decl. ¶¶ 14-16)

3. AGH could not create field development plans or field optimization plans, partly because it did not have any economists to perform an economic analysis.

a) Henderson

(1) "Outside the United States we did field studies, so we were never actually the group doing an optimization study. We would provide a subsurface piece of work which might be used in an optimization study run by the OU. So it would be incorrect to say we ran optimization studies. What we actually did was do a subsurface piece of work on a service contract and provide it to the OU. They would then put it together with other pieces of work done by other people to look at the bigger optimization picture." (Dep. pgs. 95:19-96:5)

(2) "Q. Did your . . . group create field development plans? A. We would provide . . . subsurface models that would be used in the creation of development plans . . . we had no economists . . . . Q. Do you recall who did create field development plans? A. Who did? That's usually the responsibility of the OUs themselves, because they're the ones that own the fields." (Dep. pgs. 165:24-166:15)

(3) "AGH never had any economists, so the operating unit was responsible for running the economic analysis . . . ." (Decl. ¶ 25)

b) Percival

(1) "[U]nlike the operating unit staff, [AGH and AGI] did not have the experience with, or exposure to, the local commercial and economic factors affecting field development planning. Thus, GIS staff members understood that an operating unit often would decide not to employ a creative technical solution to a problem for a range of other, non-technical reasons." (Decl. ¶ 16)

4. None of AGH's (or any of GIS's) technical services involved the estimation or reporting of proved reserves.

a) Henderson

(1) "AGH performed limited technical services for . . . operating units . . . [that] did not involve the estimation or reporting of proved reserves." (Decl. ¶ 19)

b) Percival

(1) "I am not aware of any GIS field study or technical service that estimated or reported proved reserves for any Shell operating unit, including, but not limited to, PDO. It was the responsibility of the Shell operating unit staff to estimate and report proved reserves." (Decl. ¶ 30)

I. <u>AGH's Technical Services for Petroleum Development Oman</u>

1. The technical services AGH performed for Petroleum Development Oman ("PDO") were in connection with a PDO initiative called "T50," designed to increase the recovery factor for PDO reservoirs to 50 percent.

a) The T50 initiative commenced with a 2001 PDO review and report regarding PDO's goal of increasing hydrocarbon recovery from its fields by 2030.

(1) *See* Henderson Decl. ¶ 22.

(2) *See* Percival Decl. ¶ 25.

(3) January 20-31, 2001 Target 50 PDO Growth Review. (Doc. ID#103847952)

b) PDO's realization of the T50 target of a recovery factor of 50 percent cannot be determined until the fields actually stop producing hydrocarbons.

(1) Percival

(a) "Q. And during your time at GIS, did [PDO] meet T-50? A. No . . . whether Oman actually achieves an overall recovery factor of 50 percent from its existing resource base will . . . only be known when each and every one of the fields has stopped production . . . . So in 40, or 50 years time." (Dep. pg. 150:6-14)

c) AGH's contribution to the T50 Growth Review report was not related to proved reserves.

(1) The work done by AGH directly for the T50 Growth Review report was short-lived and did not involve the estimation of proved reserves.

(a) Henderson

(i) "Q. Was there a T50 team? A. There was a two-week survey done under that project I was a part of, but that team lasted for two weeks and made a report-out." (Dep. pg. 126:20-23)

(ii) "A. It was to survey Oman's fields, just a look through each field and try to guess whether or not there might be some EOR process that could possibly be applicable through the fields. Q. What do you mean by 'guess'? A. Estimate. Guess. And a two-hour presentation on a field is far from enough to make a conclusion." (Dep. pg. 127:3-10)

(b) January 20-31, 2001 Target 50 PDO Growth Review – Phase I shows the review only lasted two weeks. (Doc. ID#103847952)

(2) PDO wrote the T50 Growth Review report with little contribution from AGH.

(a) February 22, 2001 Email from F. Bergren to T. Meijssen notes that PDO staff did "99.9% of the work on the documentation" on the T50 report (the minimal edits made by AGH can be found in the attachment to the email). (Doc. ID#57033)

2. PDO believed enhanced oil recovery ("EOR") techniques would help it meet its T50 production target. EOR is a technique whereby the application or heat, gas, or chemical injections are used to potentially dislodge and recover hydrocarbons.

a) Darley

(1) "[EOR] techniques . . . covered thermal techniques . . . the application of heat to produce oil from the reservoirs. They would also be referring to what were called miscible

technologies, which is the injection of miscible gases to release oil from the reservoir. And they may also have included . . . chemical technologies." (Dep. pgs. 287:23-288:9)

3. The work done by AGH in connection with the T50 initiative involved EOR feasibility studies, and did not involve the estimation of proved reserves volumes.

a) An EOR feasibility study is used to determine whether a particular EOR technique will help recover hydrocarbons from a field.

(1) Darley

(a) "[A] thermal [EOR feasibility] project . . . is a project to assess the opportunity to heat the rock and the fluid in the rock which is extremely heavy oil, and to test whether or not such heating would expel the heavy hydrocarbon and allow it to be produced so it's a rather -- that's why I remember it. It's a rather unusual approach, and that work was undertaken by SEPTAR." (Dep. pg. 241:14-24)

b) EOR feasibility studies do not involve the estimation of proved reserves. EOR feasibility studies are long-term studies involving many phases that assess whether EOR is even possible on a field. Given their significant expense and uncertainties, EOR techniques are rarely used.

(1) Henderson

(a) "It is highly uncertain whether a field's production will benefit from enhanced oil recovery techniques (which generally involve pumping an injectant into a well to recover hydrocarbons that cannot otherwise be recovered through conventional means). The number of variables that can affect whether EOR will even be technically possible on a given field adds to the uncertainty of the process . . . . The economic analysis of EOR techniques also makes the likelihood of implementing EOR highly uncertain. Recovering oil through EOR techniques costs considerably more than does recovery through conventional means . . . ." (Decl. ¶¶ 24-25)

(b) "[O]ur normal practice in these EOR things is to . . . do a pilot and see if it seems to work as a test before we spend a lot of money and invest in the whole field project . . . ." (Dep. pg. 157:9-13)

(c) "Q. Do you recall under what circumstances EOR was used? . . . A. So the two general places we have used it has been in California, where you have very heavy oils, where thickness or viscosity is very high, and we inject steam, which heats the oil, which reduces the viscosity and allows the oil to be produced . . . . And the other place was in West Texas where we had reservoirs which were slightly cooler than normal, which were at the right depth, and lightness of oil such that they were amenable to a miscible displacement process using carbon dioxide . . . . Those are the two areas that have been economically successful. There have been many, many failures using other attempted techniques." (Dep. pgs. 90:15-91:12)

(2) Darley

(a) "[A]n EOR project may take five to ten years in its period of gestation before it even comes . . . into development. So some of the work in SEPTAR was of an experimental nature . . . ." (Dep. pgs. 31:15-32:4)

(b) "Those studies of course were all, as is the nature of enhanced oil recovery studies I explained this morning, were very much long-term studies, looking at the future development of those resources in the five, ten, 20, 30 year time frame. Expertise in those areas . . . was vested with Lyle Henderson . . . ." (Dep. pg. 128:5-13)

(3) Percival

(a) "During the early stages of the T50 initiative, PDO expected the AGH staff to assist with the initial phases of the technical feasibility studies and then turn the projects over to PDO personnel. This transition ultimately occurred around the end of 2003, when PDO established its own technical services group in Muscat, Oman . . . . None of these studies estimated proved reserves, because . . . AGH's services were limited to preliminary EOR technical feasibility studies." (Decl. ¶¶ 27-28)

J. Specific AGH EOR Studies for PDO Fields

1. AGH performed EOR studies in connection with the T50 initiative on the Lekhwair, Al Huwaisah, Mukhaizna, Dhualaima, Harweel, Natih-B and Rahab fields in PDO. These studies did not involve the estimation or reporting of proved reserves because the studies only gave PDO some indication of whether specific EOR techniques were potentially technically feasible on a given field. The studies did not provide any assessment of the economic or commercial feasibility of the proposed EOR technique. As explained earlier, an EOR feasibility study does not involve the estimation or reporting of proved reserves.

2. AGH's work on PDO's Lekhwair field did not estimate proved reserves during the Class Period.

a) The Lekhwair study found that EOR could not be used on the field.

(1) Henderson

(a) "Lekhwair was similar. We felt that EOR using CO2 might be potential, but it turned out there is no CO2 available in Oman, so it never led to any EOR activity. We continued our field study and provided our results . . . so the OU's field team could have a better understanding of what the reservoir was about." (Dep. pg. 97:17-23)

3. AGH's work on PDO's Mukhaizna field did not involve the estimation or reporting of proved reserves.

a) The Mukhaizna study was a thermal EOR study.

(1) Henderson

(a) "We were exploring the possibility of using steam [on the Mukhaizna field] to get oil out of a reservoir that was basically setting idle, never been developed . . . ." (Dep. pg. 112:7-9)

(b) "[T]he first thing we would do is take our simulation models that we have talked about, particularly ones that are capable of handling thermal changes, like steam causes, including viscosity reduction of oil. So we build these models of the geology and the fluid characteristics. There's

> no history here to match, so it's a wider uncertainty of what will happen here. [T]he degree to which the field is complex and faulted up and broken up isn't really known. So we will make some basic assumptions, run some models, and say it might behave like this with steam, but we don't really have any experience here, so . . . our normal practice in these EOR things is to . . . do a pilot and see if it seems to work as a test before we spend a lot of money and invest in the whole field project . . . ." (Dep. pgs. 156:17-157:23)

b) The Mukhaizna study did not succeed in finding an EOR opportunity.

(1) Henderson

(a) "Nothing came of the Mukhaizna work." (Dep. pg. 112:25)

4. AGH's work on PDO's Al Huwaisah field did not involve the estimation or reporting of proved reserves.

a) The Al Huwaisah field study was an EOR study and a well placement study that found no EOR opportunity and no new drill locations.

(1) Henderson

(a) "Q. Do you recall the results of the Al Huwaisah study? A. That was a particularly difficult one. It's a fractured reservoir. We were trying to find if there were additional places to drill in Al Huwaisah. We thought EOR might be a possibility. It turned out that it was not." (Dep. pgs. 96:21-97:3)

(b) "I think we did recommend a couple of possible drilling locations, but . . . the OU had already identified those same locations." (Dep. pg. 97:4-6)

5. AGH's work on PDO's Dhualaima field did not involve the estimation or reporting of proved reserves.

a) The Dhualaima field study was an EOR study done in conjunction with the Lekhwair field study, and AGH did not find any EOR opportunities.

(1) Henderson

(a) "T]he Lekhwair team looked at that while they were looking at Lekhwair." (Dep. pgs. 143:25-144:3)

(2) Henderson

(a) "Q. Do you recall the results of that work? A. We did no EOR as a result of it. We could not find a miscible injectant available . . . ." (Dep. pg. 144:15-17)

6. AGH's work on PDO's Harweel Cluster did not involve the estimation or reporting of proved reserves.

a) AGH merely sent out one employee to perform a simulation on the Harweel Cluster.

(1) Henderson

(a) "The Harweel cluster was . . . one EOR project [PDO] might do. It's a new development where they might re-inject to produce gas, which becomes miscible of the oil because of the high temperatures and pressures . . . . [T]he service there was not a field study . . . . [O]ne of my reservoir engineers provided a specific one-person service of making some simulation runs because of our experience with miscible displacement from West Texas, so we just made a couple of runs and gave them the simulation..." (Dep. pg. 108:12-23)

7. AGH's work on PDO's Natih B field did not involve the estimation or reporting of proved reserves.

a) AGH performed a very experimental EOR study on the Natih B field.

(1) Darley

(a) "Q. Beneath that is Natih B thermal conduction project. Are you familiar with that project, sir? A. Yes, I am. It was a rather unusual project . . . ." (Dep. pg. 241:2-6)

(b) "[T]his [was] very embryonic kind of research . . . testing whether or not this technique might at all ever in the next 50 years become viable in the case of the Natih B [field]." (Dep. pg. 242:10-15)

8. AGH performed an EOR feasibility study on the Rahab field, but this study did not involve the estimation or reporting of proved reserves.

a) *See* Percival Decl. ¶ 28.

K. Services Performed by AGH for Shell Venezuela, S.A.

1. AGH worked on two projects for Shell Venezuela S.A. ("SVSA") between 2000 and 2003. One project involved studying three reservoirs in the Urdaneta West field. The other project involved a study of the Marsical Sucre Liquid Natural Gas ("MSLNG") project.

a) AGH completed technical studies on three reservoirs in the Urdaneta West field for part of a field optimization study.

(1) The work performed by AGH on the Urdaneta West field did not involve the estimation or reporting of proved reserves. This work only involved mapping the subsurface with reservoir simulation models.

(a) Henderson

(i) "AGH created a few reservoir simulation models for Shell Venezuela, S.A. ("SVSA"), a Shell operating unit. AGH members worked on two projects for SVSA intermittently between 2000 and 2003: the Urdaneta West field and the Marsical Sucre LNG Project. AGH's work for SVSA did not involve the estimation or reporting of proved reserves, because the studies involved only the creation of reservoir simulation models. A model of the subsurface is simply a tool the operating unit might use to better understand its hydrocarbon fields. The model's accuracy is uncertain and can be confirmed, or disproved, only through further exploration by the operating unit. Such models do not estimate the operating unit's proved reserves." (Decl. ¶¶ 20-21)

(ii) "We worked the [Urdaneta West] fields to try to help them with their development planning and optimization work. I think those are the main optimization-related pieces of work we did." (Dep. pg. 96:15-18)

(iii) "A. Urdaneta West is the field name, and I said there were three reservoirs . . . we worked on. Q. And what type of work did your team do? A. We were trying to again create models of the reservoir, so we did geologic studies looking at all the technical data of the wells and cross-sections and maps and seismic, and then we tried to understand fluid flow in the rock . . . and get some idea if we could help the OU down there find drilling locations. We were looking for really techniques to help them spot where to put wells." (Dep. pgs. 180:24-181:16)

(2) The studies on these reservoirs were largely unsuccessful, and no action was taken by SVSA upon their completion.

(a) Henderson

(i) "We failed to find a way to spot wells in both the Cogollo and the Icotea/Misoa. We provided some simulation models of what waterflooding might do in the Rio Negro. I don't believe a waterflood was ever put in, though." (Dep. pg. 182:2-6)

(b) Percival

(i) "Do you recall the result of the work on [the Urdaneta West] . . . field . . . ? A. I can't remember because the work stopped because of political stuff." (Dep. pg. 130:13-16)

b) AGH's work for the MSLNG project did not involve the estimation or reporting of proved reserves.

(1) Henderson

(a) "AGH's work for SVSA did not involve the estimation or reporting of proved reserves . . . ." (Decl. ¶ 21)

L. AGH Did Not Perform Technical Services in Malaysia

1. There is no evidence that AGH performed any technical services in Malaysia.

a) In mid-2003, AGH was contacted about a possible EOR study in Malaysia. The fact that AGH was contacted just before SEPTAR disbanded suggests this work was not performed by AGH, if at all.

(1) June 26, 2003 Email from J. Sutherland to C. Hsu shows AGH was contacted in mid-2003 about a potential EOR project in Malaysia. (Doc. ID#140981)

M. AGH's Services for Shell Exploration China Ltd.

1. AGH performed technical services for Shell Exploration China Ltd. ("SECL"). The Group Reserves Auditor, Anton Barendregt, conducted his 2001 audit of SECL in Houston in part because the technical data on some of SECL's fields was in the BTC. AGH did not estimate or report SECL's proved reserves.

a) Barendregt

(1) "My audit of SECL in 2001 was conducted in Houston, Texas, because SEPTAR's Houston office was providing technical services to SECL. At all times SECL, not SEPTAR, held the final responsibility for estimating its oil and gas resources and submitting those estimates to E&P." (Decl. ¶ 18)

b) Percival

(1) "I am not aware of any GIS field study or technical service that estimate or reported proved reserves for any Shell operating unit." (Decl. ¶ 30)

c) Henderson

(1) "AGH performed limited technical services for other operating units . . . [which] did not involve the estimation or reporting of proved reserves." (Decl. ¶ 19)

2. SECL's restated volumes are wholly insignificant and immaterial to the alleged fraud in this case. SECL restated only 0.001 billion barrels of oil equivalent ("bboe") for 2002, which constituted only 0.022% of the 4.47 bboe restatement that Shell announced in its Form 20-F for 2003. Furthermore, the volumes were restated because of issues related to SECL's use of incorrect product prices to estimate volumes. These issues

had no connection to the work performed by AGH.

a) Barendregt

(1) "[A]lthough SECL later recategorized certain proved reserves in 2004, this recategorization related to SECL's use of the Group's internal project-screening values rather than year-end prices to calculate its proved reserves entitlements, not to any technical work performed by SEPTAR." (Decl. ¶ 18)

b) *See* Cooper Decl. ¶¶ 49-50 and corresponding chart showing the amount of China's restated reserves.

c) Proved Reserves Booking Lookback describes the reason for the restatement. (Doc. ID#600000000004867)

N. Services Performed by AGI (and Rijswijk-based members of SEPTAR)

1. AGI, in Rijswijk, was the dominant sub-cluster in GIS.

a) AGI accounted for most of GIS's revenue.

(1) January 25, 2001 Profit and Loss 2000 shows that the AGI sub-cluster accounted for more than one-third of all GIS's revenue and for more than three times the revenue of AGH. (Doc. ID#103847088)

b) Most of GIS's staff was in AGI.

(1) Percival

(a) "AGI also was a much larger sub-cluster than was AGH. AGI therefore performed the majority of GIS's integrated field study work. For example, AGI had in the order of 60 staff members devoted exclusively to performing technical services for the Shell Petroleum Development Company of Nigeria ("SPDC") . . . ." (Decl. ¶ 21)

(2) GIS Staff Plan shows that in June of 2002, AGI was the largest sub-cluster in GIS and was three times larger than AGH. (Doc. ID#200000005990472)

2. The technical services that SEPTAR performed for SPDC were supplied exclusively by SEPTAR's Rijswijk office and had no connection with the United States.

   a) The Houston-based members of AGH and the other GIS sub-clusters did not do any work for SPDC.

      (1) Percival

         (a) "The SEPTAR staff [who performed services for SPDC] were all based in Rijswijk." (Decl.¶ 21)

   b) AGI, located entirely in SEPTAR's Rijswijk office, performed technical services for SPDC.

      (1) Percival

         (a) "Q. Do you recall if GIS did work for SPDC? A Yes, they did. Q. And do you recall where that work was done? A. That was done exclusively in Rijswijk." (Dep. pg. 150:21-25)

         (b) "A. In SPDC . . . we had a tighter structure . . . . Richard Waterland . . . was in charge of all activities in Nigeria, simply because . . . Nigeria was more of a challenge to deal with in terms of remuneration and agreement on Terms of Reference. Q. And where was he located? A. In Rijswijk." (Dep. pgs. 68:24-69:8)

         (c) "Q. It mentions that you co-sponsored a Nigeria Seamless Team; is that correct? A. Yes. Q. And what was that? A. This was an effort to gather as much collaboration between the people working in Rijswijk . . . working closely with their opposite numbers in SPDC, which is the Shell Petroleum Development Company in Nigeria, to basically improve performance across the board." (Dep. pgs. 111:23-112:9)

         (d) "For example, AGI had in the order of 60 staff members devoted exclusively to performing technical services for the [SPDC]. This group was known as the SPDC 'seamless team,' because it allowed SPDC to have services performed rapidly, without staffing or coordination delays. It was composed of both SEPTAR staff and national staff seconded from SPDC for a duration dependent on each project. Total staff numbers would flux depending on the number, complexity and maturity of projects at any time. The SEPTAR staff on the SPDC 'seamless team' was all based in Rijswijk." (Decl. ¶ 21)

(2) Okon

(a) "[L]imited technical services . . . [to SPDC] were provided exclusively by the SEPTAR team referred to as AGI, which was based in Rijswijk." (Decl. ¶ 6)

(3) Bichsel

(a) "A. SEPTAR in Rijswijk, for instance, would do field development studies for a number of operating companies that included SPDC, Gabon, in the African continent. They would be working for Malaysia on the gas development." (Dep. pg. 226:2-8)

(4) Kluesner

(a) "Q. And when you say that Rijswijk has a group that is devoted to studying, doing studies for SPDC, was that group -- had that group been part of SEPTAR? A. It would have been part of SEPTAR in Rijswijk when it was SEPTAR, yes." (Dep. pg. 175:7-12)

(5) Darley

(a) "Q. Do you recall which SEPTAR office was involved in those development studies? And by that I mean was it Rijswijk versus Houston? A. The Nigerian work was undertaken in Rijswijk. For SPDC." (Dep. pgs. 22:23-23:4)

(b) "Q. With regard to the work done in connection with Ughelli by SEPTAR, could you please describe that for me? A. As I recall, that was field development plan type studies. Q. Do you recall which office, Rijswijk or Houston, did work on Ughelli? A. That would have been the Rijswijk office." (Dep. pg. 92:4-13)

(c) "Q. Do you have any specific recollection of the individuals from SEPTAR who actually performed work in that regard at SPDC? A. I don't recall who they were. Q. Do you recall what office, and by that I mean either Rijswijk or Houston, those individuals were from? A. They would certainly have been from the Rijswijk office . . . . [T]he SPDC study teams were . . . based in Rijswijk, and it may be that members of those study teams were asked to support the Nigeria work, and again, they would then be from Rijswijk." (Dep. pgs. 152:17-153:17)

(6) Aalbers

(a) "Q. Do you know if SPDC was performing the technical work in the EA field? A. I believe quite a bit of the EA study work was farmed out . . . to Rijswijk to do on their behalf. There was a large Nigeria study team in The Hague or Rijswijk." (Dep. pgs. 280:23-281:4)

(7) August 18, 2003 Email from P. Egele to A. Barendregt notes that "the SEPTAR – SPDC critical issues meeting" will take place in Rijswijk. (V00132055-58)

3. AGI (or RTS prior to the formation of SEPTAR) performed most of SEPTAR's technical services for PDO Oman, including on the Marmul, Karim West, Nimr G, Nimr C, and Zauliyah fields.

a) Kennett

(1) "Q. During your time . . . from 1997 to 1999 . . . at PDO Oman . . . [did you have] any interaction at all with SEPTAR? A. [T]here were studies being carried out . . . by the field study groups in Rijswijk in Holland . . . . The work was not being carried out in the United States at that time." (Dep. pgs. 121:18-122:13)

(2) *See* Kennett Decl. ¶ 13.

b) Darley

(1) "Q. Do you recall which office within SEPTAR, either Rijswijk or Houston, was primarily responsible for the work in Oman? A. Most of the work that was done for Oman was undertaken in Rijswijk . . . ." (Dep. pgs. 27:23-28:5)

c) AGI, not AGH, performed services on the Marmul field.

(1) *See* Percival Dep. pgs. 143:24-144:7.

(2) *See* Henderson Dep. pg. 79:9-22.

d) AGI, not AGH, performed services on the Karim West field.

(1) *See* Percival Dep. pg. 143:16-21.

(2) *See* Henderson Dep. pg. 108:8-10.

e) AGI, not AGH, performed services on the Nimr C and G fields.

(1) *See* Percival Dep. pg. 145:11-25.

(2) *See* Henderson Dep. pg. 111:19-21.

f) AGI, not AGH, performed services on the Zauliyah field.

(1) *See* Percival Dep. pgs. 138:13-139:2.

(2) *See* Henderson Dep. pgs. 111:21-112:2.

g) November 28, 2002 GIS-EDP comparison notes that AGH began working in PDO in 2001. (Doc. ID#104293158)

h) June 5, 2002 Oman Organogram shows that AGI staff in Rijswijk and Aberdeen worked on more PDO fields with considerably more staff members than did AGH. (Doc. ID#0000000000056793)

i) January 3, 2002 PDO Projects SepTAR Overview shows that at the beginning of 2002, there were 25 SEPTAR Rijswijk staff members and 7 SEPTAR Houston staff members working on PDO projects. (Doc ID#200000005990435.0)

TAB 9

FACT SUMMARY

IX. GROUP RESERVES AUDITOR'S HOUSTON AUDITS

Shell's Group Reserves Auditor (the "GRA") – who reviewed the aggregate proved-reserves estimates that the Group Reserves Coordinator compiled in the Netherlands – was himself based in the Netherlands, but he conducted periodic audits of Shell's worldwide operating units at the operating units themselves or, occasionally, at other places where the operating units' data were located. Plaintiffs have noted that, during the Class Period, the GRA conducted several of those audits in the United States. Those audits, however, did not constitute significant and material conduct in furtherance of the alleged fraud, and they certainly did not directly cause the Non-U.S. Purchasers' claimed losses.

First, the GRA performed only six audits in the United States – a small portion of the approximately 40 to 50 audits he conducted during the Class Period.[104] The GRA conducted the vast majority of his audits outside the United States, usually at the operating units themselves.[105]

Second, four of the GRA's six audits in the United States were of operating units that did not restate or reduce *any* proved reserves at all, or only trivial amounts. Those audits thus could not have any conceivable relevance to this case.

- The audited Cameroon and Brazil fields did not restate or reduce *any* proved reserves during the Class Period.[106]

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104 *See, e.g.,* Barendregt Decl. ¶ 17; Barendregt Dep. at 192:2-4; *see also* Review of Group End-2002 Proved Oil and Gas Reserves Summary by Barendregt, Attachment 7 (Doc. #HAG00203653-69).

105 Barendregt Decl. ¶¶ 13-17.

106 Cooper Decl. ¶ 35; Barendregt Decl. ¶ 22 (explaining that his Houston audit related to the Merluza field in Brazil, for which no proved reserves were recategorized (although proved reserves in a separate Brazilian field – Bijupira/Salema – were recategorized, *see* Cooper Decl.

- SEPCo did not restate any proved reserves at all for each of year-end 1999, 2000, 2001, or 2002, and its reduction in proved reserves that Shell had expected to report for the United States for 2003 constituted only 0.05% of Shell's aggregate 2003 reported proved reserves.[107]

- SECL's restatement of 0.001 bboe for 2002 amounted to only 0.022% of the 4.47 bboe restatement that Shell announced in its 2004 Form 20-F.[108]

The remaining two audits were of SNEPCO and SDAN, discussed in detail in Section VII, above. The GRA conducted those audits in Houston because SDS had SNEPCO's and SDAN's technical data. Plaintiffs thus are effectively "double-counting" United States contacts: the GRA went to Houston because SDS was there, so the Houston audits do not add anything to the SDS contacts already discussed. And for the reasons explained above, SDS's U.S.-based contacts with SNEPCO and SDAN do not come even close to satisfying the conduct test.

Third, there is no evidence that the GRA's U.S. audits in any way *furthered* an alleged fraud in connection with Shell's overestimating its proved reserves. To the contrary, the GRA's Houston audit of SNEPCO in 2002 recommended *reducing* certain proposed additions to proved reserves and *debooking* other previously reported proved reserves.[109]

Fourth, the GRA's audits and their proved-reserves figures were not the information that Shell reported to the public. As discussed above in Section IV, the ARPR process still required (*i*) the Group Reserves Coordinator's (the "GRC's") review in the

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¶ 44)); *see also* Doc. #600000000009741 (showing recategorization of Bijupira/Salema proved reserves); Doc. #RJW00061551-60 (showing that Pecten owned Merluza field).

107 Cooper Decl. ¶¶ 72-73 and accompanying table.

108 Cooper Decl. ¶¶ 49-50 and accompanying table.

109 Doc. #RJW00061540-50. Similarly, on a non-audit visit to Houston, the GRA advised SDS that a booking of proved reserves for SDAN was not supportable. Barendregt Decl. ¶ 24(a).

Netherlands, (*ii*) the "challenge session" session in the Netherlands with the GRC, the GRA, the Deputy Group Controller, and the external auditors (KPMG and PwC), and (*iii*) approval by the EP Executive Committee in the Netherlands before Shell's aggregate proved-reserves estimate could be reported to the public by Shell's Investor Relations and External Affairs departments in and from Europe.

FACT SUPPORT

IX. GROUP RESERVES AUDITOR'S HOUSTON AUDITS

See Section IV.B.3. *supra*

TAB 10

FACT SUMMARY

X. MISCELLANEOUS SHELL ORGANIZATION FACTS

Plaintiffs also have inquired about other entities, organizations, meetings, and initiatives that somehow might link Shell's reporting of proved reserves to some form of U.S.-based conduct. Many of those entities and organizations combined to become, or arose after the disbanding of, SDS and SEPTAR, discussed above. There is no evidence that any of those organizations estimated or reported proved reserves.

Most of the remaining organizations, entities, and activities were based in the Netherlands (in Rijswijk) and had insignificant connections to the United States. There is no evidence that any of those organizations, entities, or activities involved the estimating or reporting of proved reserves in connection with the ARPR process. These wholly peripheral matters are discussed in Section X of the accompanying factual submission.

FACT SUPPORT

X. MISCELLANEOUS SHELL ORGANIZATION FACTS

Plaintiffs have asked witnesses about, and requested documents regarding, the following Shell entities, initiatives, and meetings. As explained below, there is no evidence that any of these entities, initiatives or meetings estimated or reported proved reserves in connection with the Annual Review of Petroleum Reserves ("ARPR") process.

A. EP Projects

1. EP Projects was formed in 2002.

   a) December 31, 2002 STEP Direction brochure notes that EP Projects formed on July 1, 2002, with offices in Houston, New Orleans, Rijswijk, and Aberdeen. (RJW00192135-42)

2. EP Projects coordinated facilities engineering work. There is no evidence that it estimated or reported proved reserves in connection with the ARPR process.

   a) Bichsel

      (1) "We have an organization which is called EP Projects. EP Project . . . is the development organization of the facilities engineers that put the steel in the ground." (Dep. pg. 142:4-9)

   b) Sears

      (1) "EP Projects was a global technical service provider to do surface engineering for major projects around the world." (Dep. pg. 87:7-9)

3. The director of EP Projects was located in Rijswijk.

   a) Sears

      (1) "The director of EP Projects was located in Rijswijk." (Dep. pg. 87:11-12)

B. Entities Created During the Reorganization of Shell Exploration and Production Technology, Applications and Research and Shell Deepwater Services

1. EPT Solutions (also referred to as EP Solutions)

a) EPT Solutions was officially created on January 1, 2004, but the organization was effective from mid-2003 onwards.

(1) *See supra* Section VIII.C.

b) EPT Solutions is a combination of the technical services groups from Shell Exploration and Production Technology, Applications and Research ("SEPTAR") and Shell Deepwater Services ("SDS").

(1) Darley

(a) "[P]art of the SEPTAR group that was concerned with studies had been reallocated to a unit called EPT Solutions. . . . [T]he subsurface groups in SDS were redeployed as part of EPT Solutions . . . ." (Dep. pgs. 171:25-172:6)

c) EPT Solutions had offices in Houston, Aberdeen, Rijswijk and New Orleans, but the director was located in Rijswijk.

(1) Sears

(a) "Q. Where was EP Solutions located? A. The director was in Rijswijk . . . . Q. Where else did EP Solutions have locations? A. In Aberdeen, in Houston, and in New Orleans." (Dep. pg. 86:15-21)

d) There is no evidence that EPT Solutions estimated or reported proved reserves in connection with the ARPR process.

2. EPT Research (also referred to as EP Research)

a) SEPTAR's research clusters became EPT Research after the reorganization of SEPTAR and SDS.

(1) *See supra* Section VIII.C.

b) There is no evidence EPT Research estimated or reported proved reserves in connection with the ARPR process.

3. EPT Wells (also referred to as EP Wells or EP Well Delivery)

a) EPT Wells was created from the reorganization of SEPTAR and SDS.

(1) Darley

(a) "And in the case of [EPT Wells], SepTAR wells group would work with the Deepwater wells group to form one aligned global entity in support of the EP business." (Dep. pgs. 309:25-310:4)

b) There is no evidence EPT Wells estimated or reported proved reserves in connection with the ARPR process.

C. <u>Shell Global Solutions</u>

1. Shell Global Solutions provided consultancy services on surface facilities. There is no evidence that it estimated or reported proved reserves in connection with the ARPR process.

(1) Hines

(a) "[Shell Global Solutions is] an internal service provider that provides consultancy services for engineering services covering the exploration production midstream and also the downstream part of our business, so construction of refineries . . . ." (Dep. pgs. 84:24-85:4)

(2) Darley

(a) "Q. With respect to the entity you just mentioned, Shell Global Solutions, was that organization also part of EPT? A. No . . . . Q. Do you recall organizationally where [Shell Global Solutions] fit in? . . . A. It was part of the downstream organization in Shell." (Dep. pg. 24:23-25:16)

(b) "[I]n general terms, [Shell Global Solutions] undertook the work that was related to surface facilities. So pipelines, separator facilities, gathering station facilities, that was their area of expertise." (Dep. pg. 69:9-14)

2. Shell Global Solutions has offices in Houston and Risjwijk, but it is based in the latter.

(1) Darley:

(a) "Q. Do you know where [Shell Global Solutions] was located . . . ? A. Yes, it was based out of Rijswijk and out of Houston." (Dep. pg. 69:15-19)

D. Shell Technology Ventures

1. Shell Technology Ventures ("STV") commercialized technology developed by Shell. There is no evidence that it estimated or reported proved reserves in connection with the ARPR process.

a) Bichsel

(1) "Shell Technology Ventures commercializes technologies that the research organization has developed . . . ." (Dep. pgs. 227:24-228:2)

b) January 31, 2000 ExCom Note for Information describes the commercialization of expandable tubular technology created by a joint venture between Halliburton and Shell (SEPTAR). (Doc ID#100196618)

2. STV comprised a Rijswijk entity and a separate Houston entity.

a) Bichsel

(1) "STV has two legal entities, one in Holland and one in the United States, so in Houston and in Rijswijk. There's an STV B.V. and an STV, Inc." (Dep. pg. 228:15-19)

E. Deepwater Steering Council

1. The Deepwater Steering Council ("DWSC") is a virtual organization without staff, offices, or formal meetings. There is no evidence that it estimated or reported proved reserves in connection with the ARPR process.

a) Varley

(1) "Q. Do you know whether [DWSC] had any offices? A. No. It wasn't a formal organization. It was a group of individuals with an interest in deepwater development." (Dep. pg. 165:9-13)

b) Bichsel

(1) "Q. Where was the Shell Deepwater Council located? A. The . . . Deepwater Steering Council is a virtual body." (Dep. pg. 263:10-14)

(2) "DWSC primarily focused on general monitoring and allocation of deepwater technical resources, not on the estimation or reporting of proved reserves." (Decl. ¶ 41)

c) Minderhoud

(1) "[The DWSC] was an informal group in the sense not part of the formal structure of the company. And as such we would not have had formal meetings." (Dep. pg. 49:7-10)

F. <u>Bellaire Technology Center</u>

1. Bellaire Technology Center ("BTC") is the physical grouping of buildings in Houston that housed SEPTAR.

a) Hoffman

(1) "Q. So you mentioned earlier that you physically worked at the Bellaire Technology Center. Is that just as you described, a group of buildings, or is it actually a cluster of some sort or division? A. So Bellaire Technology Center . . . is a group of buildings . . . ." (Dep. pg. 40:6-12)

b) *See supra* Section VIII for a discussion on SEPTAR.

G. <u>Shell Services International</u>

1. Shell Services International ("SSI") was a collection of data centers located in various cities. There is no evidence that SSI estimated or reported proved reserves in connection with the ARPR process.

a) Formed in 1998, SSI had hubs in Rijswijk, Houston, Kuala Lumpur and Melbourne.

(1) Brass

(a) "Q. Where was Shell Services International located? A. In the Netherlands. That was the . . . Head Office of Shell Services International. Q. And where had Shell Services Company been located? A. In Houston. Q. Did it remain in Houston after Shell Services International was formed? A. It became one of the hubs we had in Shell Services International. By far the largest. Q. What were the other hubs? A. Kuala Lumpur, and a small one in Melbourne, Australia." (Dep. pg. 22:6-20)

b) The Data Centers in the Houston and Rijswijk hubs were wholly independent.

(1) Brass

(a) "Q. [W]as the Shell Services International in Houston using the same mainframe . . . as the office in the Netherlands? A. No. They had their own mainframes." (Dep. pg. 28:12-16)

2. SSI was an entity that simply stored data. It had no role in data interpretation.

a) Brass

(1) "Again Shell Services was a data processing center. It basically ran the data on very large mainframe computers. We obtained the data from whoever had taken the seismic information in, we'd process that data and then gave it back to people for interpretation. . . . Shell Services International is a data processing facility, [it] had nothing to do with the interpretation of that data." (Dep. pg. 35:19-36:6)

H. <u>Technical and Operational Excellence</u>

1. The Shell EP Executive Committee launched the Technical and Operational Excellence ("T&OE") initiative in March 2002 to improve technical and operational standards across the entire EP business.

a) T&OE was launched in early 2002.

(1) J. Bell

(a) "Q. [T&OE] was created in 2002? A. [Yes]." (Dep. pg. 284:11-15)

(2) Nauta

(a) "Q. So is it your best recollection then that the T&OE was launched in or about March -- A. Yes. Q. -- of 2002?" (Dep. pg. 208:4-8)

b) T&OE was located in Rijswijk, where its leader was also situated.

(1) Ward

(a) "A. I was head of [T&OE] . . . . Q. And where was the center for technical operations and excellence? A. In The Hague, in Rijswijk." (Dep. pg. 37:14-23)

(2) Varley

(a) "Q. Does T&OE have its own offices? A. They do have their own offices . . . in our, Shell's Rijswijk complex." (Dep. pg. 148:18-22)

(3) Van Driel

(a) "Q. And where was the T&OE located? A. In Rijswijk." (Dep. pg. 232:17-18)

c) T&OE was a global initiative tasked with reviewing EP's operational practices across a wide spectrum of activities.

(1) T&OE leaders would consult with operating units (who were not a part of T&OE) to determine how practices differed from operating unit to operating unit. Then T&OE would identify minimum standards and/or best practices and share them with many operating units worldwide.

(a) Darley

(i) "In the first instance it was necessary to define a process and the definition of the process then involved each of the operating units around the world working on a given process for a given activity, facilitated by T&OE consultants, to come to an agreed process, and that was based on global input." (Dep. pg. 208:9-21)

(ii) "[T]he [T&OE] objective was to improve the business, and a number of measures were put in place to improve the business. One of those measures was . . . to define minimum standards. Another would be to identify best practices. Another would be to define recommended processes. The implementation of those minimum standards and recommended processes was then indeed to be taken up by operating units around the world." (Dep. pgs. 206:22-207:9)

(iii) "Having then agreed that process, indeed it was up to the operating units to adopt the agreed [T&OE] process." (Dep. pg. 208:18-21)

(b) Hoffman

(i) "[T&OE] was put together to address specific issues, and one of the issues was if you went to different operating units around the world, they did their work differently. And it was felt that if they did their work the same way, that there would be benefits to the company from . . . [a] standardized approach." (Dep. pgs. 99:11-92:20)

(c) Pay

(i) "[T&OE] was an organization that was introduced in the central office in The Hague comprising . . . some 20 or so experts in various aspects of field development and operations. I . . . was not a part of that organization. However, my understanding of . . . this organization as I perceived it was to ensure that oil field operational practices around the group were harmonized and . . . this central community would provide a conduit for good practices, practices that had been found to benefit one operations in one company would easily disseminated to the rest of the group companies so that all might benefit from it." (Dep. pg. 280:6-21)

(2) T&OE initiatives covered a wide range of aspects of EP, including reviews of operating and drilling costs and production geology.

(a) J. Bell

(i) "[One T&OE initiative I was involved in was] to look to see where we could reduce the costs of running our business." (Dep. pg. 132:7-19)

(b) Nauta

(i) "Q. Once the T&OE became operational, what interaction did you have with the T&OE? A. . . . There's . . . the so-called functional improvement where we would try to get a handle on future drilling costs, for example . . . ." (Dep. pg. 211:9-21)

(c) See Ward Dep. pg. 208:4-10 discussing T&OE's role in setting standards for production geology.

(3) T&OE initiatives also covered techniques such as waterflooding, increasing production from existing wells, oil processing facilities, and reserves maturation.

(a) Brass

(i) "A. It stands for "Technical and Operational Excellence," and there [were] . . . a number of various activities that were identified to improve the business, both on the technical and the operational side. Q. And what were some of those? A. . . . [T]here were teams that were looking specifically at enhanced recovery; for instance, waterfloods. There was a team that was looking at . . . ways to improve production rates from existing wells. There was a team targeted towards . . . the maturation of the reserves . . . there was some also related to the actual facilities where a lot of the oil and gas are processed. So it spanned elements of the entire Oil and Gas or most all of the Oil and Gas operations." (Dep. pg. 340:7-24)

d) There is no evidence that T&OE estimated or reported proved reserves in connection with the ARPR process.

I. Exploration and Production Leadership Forum

1. The Exploration and Production Leadership Forum ("EPLF") was a gathering of Shell EP Executive Committee members and other senior managers.

   a) J. Bell

      (1) "Q. [W]hat was the purpose the [EP] Leadership Forum? A. It is an extension of the EP Leadership Team which brings down the next level of detail. We meet periodically to ensure that we have consistency of message . . . . Q. And who are the members of the Leadership Forum? A. Basically the people that work for the members of the EP Executive Committee plus the Executive Committee itself." (Dep. pgs. 252:17-253:5)

2. Only a single one-day meeting per year occurred in the United States.

   a) Gardy

      (1) "EP leadership forum is, in abbreviation, called EPLF, EP Leadership Forum, and it has been a gathering of some -- between 100 to 140 EP senior people attending two events a year, one . . . in Houston . . . ." (Dep. pg. 215:10-15)

   b) Although reserves may have been discussed as a general overview of Shell's business, there is no evidence that the EPLF estimated or reported proved reserves in connection with the ARPR process.

      (1) Ratcliffe

         (a) "Q. Do you recall attending an extended EP meeting (the EPLF) in or about late 2001/early 2002 in which the need for an increase in reserves was discussed? A. I recall being in such a meeting. I don't recall the exact date . . . but it could have been in 2002 when indeed we discussed all the business drivers, including the need for reserves additions in Shell." (Dep. pg. 185:2-13)

J. Hydrocarbon Maturation Leadership Team

1. The Hydrocarbon Maturation Leadership Team ("HMLT") had almost no connection to the United States and, in any event, there is no evidence that it estimated or reported proved reserves in connection with the ARPR process.

a) The HMLT had its inaugural meeting in September of 2002 in Rijswijk.

(1) Knight

(a) "Q. [T]his document refers to the inaugural meeting of the [hydrocarbon maturation leadership team]. Do you recall whether there were subsequent meetings of the team? A. I think there were other meetings of the team, but I have to admit I only recall this one [in Rijswijk] . . . . Q. And was it pursued further? A. It may have been. I think largely the events of 2003 globalization just overtook this initiative." (Dep. pgs. 68:21-69:19)

b) Fred Hoffman, a Houston-based SEPTAR member, was a peripheral member of this team for a short period of time.

(1) Hoffman

(a) "[A]nd so there were primary members of the [HMLT], and those would be the development managers in the operating units . . . those were the core members of the team. I was a peripheral member of the team, and my job was to carry messages about technology back and forth." (Dep. pg. 96:4-10)

(b) "Q. Do you recall being part of a hydrocarbon maturation leadership team in about 2002? A. Yes. Q. Do you remember what that team did in 2002? A. . . . I attended several meetings of that team, one, two or three, and then I was replaced. I was a representative from SEPTAR under the team. They looked at issues around our entire how to mature reserves, and let me set the context here of what I mean when I talk about reserves: All the way from pre-discovery or undiscovered reserves to scope for reserves to expected reserves to booked reserves, that whole chain." (Dep. pg. 95:9-25)

c) Steve Sears from EP's United States operating unit, SEPCo, was also a member.

(1) September 20, 2002 Minutes of Meeting shows the attendees of the HMLT meeting in Rijswijk. (Doc ID#101324901)

K. Realizing the Limit Initiatives

1. Realizing the Limit ("RTL") was the umbrella under which a series of initiatives were undertaken from EP's Rijswijk office to achieve technical best practices. There is no evidence that the RTL initiatives estimated or reported proved reserves in connection with the ARPR process.

a) There were four initiatives associated with RTL: Volumes to Value, Drilling the Limit, Capital to Value, and Producing the Limit.

(1) McKay

(a) "There's a collection of initiatives known as the limits. There is drilling the limit . . . . There was also volumes to value . . . . There was one called capital to value . . . . [Later there] was producing the limit . . . ." (Dep. pgs. 58:7-59:14)

b) RTL initiatives were attempts to achieve the theoretical best results from Shell's technical drilling or production efforts.

(1) Hoffman

(a) "A. Again using the example of Drill The Limit, so we're currently drilling a lot of wells of different kinds, and we're drilling them with a certain level of effectiveness, and you stand back from a physics standpoint and say what's the best we could possibly do under any circumstance, using the laws of physics as we know them . . . you ask the question: What can we do to move closer to the technical limit? Think of it as continuous performance improvement. Q. When you reference "the gap," were there things called "gap reserves" that you're aware of? A. No. When I said "gap," it had nothing to do with reserves. It was a difference between where we were at a certain point in terms of our technology and what we might strive for. That's the gap I'm referring to. Q. Is that a gap in production? A. No. This is a gap in a particular activity, like drilling. Now, if it's Produce The Limit, then yes, you'd say, okay, here's where our current production level is. Under best possible case and technical limits, here's where it could be, and so how can we move from where we are to where we could be." (Dep. pgs. 94:7-95:8)

(2) Warren

(a) "Q. In connection with the work of the Drill the Limit Program was there any consideration given to proved reserves? A. No." (Dep. pg. 202:4-7)

c) These initiatives were implemented from Rijswijk. They were not connected to the United States.

(1) Darley

(a) "[T]he RTL consultants were based in Rijswijk. So if we're talking about realizing the limit type of work, then that was sourced from Rijswijk." (Dep. pg. 153:7-11)

(b) "Dan Antheunis' role in Rijswijk at that time covered a lot of the work of the RTL teams that we'd spoken about yesterday. And we didn't have RTL teams in Houston . . . ." (Dep. pg. 316:15-19)

d) There is no evidence that Houston-based members of SEPTAR used the processes created by the RTL initiatives.

(1) Henderson

(a) "Q. Was that a certain methodology that you used in evaluating fields? A. I never used [RTL methodogies]. Q. Do you know if your team used it? A. I think they may have participated in some of these limit process meetings. Q. Do you recall details about any of those meetings? A. I didn't attend the meetings, so I don't . . . . My recollection is not good enough that I can bring up where they may have gone through any of those limit processes. They weren't too many times they were involved, and I really can't recall which fields they were on." (Dep. pgs. 38:6-39:4)

e) When the T&OE office was created in Rijswijk, the RTL groups were moved into T&OE.

(1) Darley

(a) "When [T&OE] was formed in 2002, it took groups that had been part of EPT, in particular the realize the limit groups and the value assurance groups, and it moved them under one of my colleagues, Brian Ward, who was then leader of that organization." (Dep. pg. 206:2-9)

TAB 11

FACT SUMMARY

XI. SHELL'S U.S. INVESTOR-RELATIONS ACTIVITIES

Plaintiffs also have contended that Shell's investor-relations ("IR") activities in the United States somehow constitute sufficient U.S.-based conduct to allow *non-U.S.* persons who bought Shell stock on *non-U.S.* markets to sue in the United States under the federal securities laws. The issue here is not whether Shell made any alleged misrepresentations to Non-U.S. Purchasers about its proved reserves. The only question is the *location* from which Shell communicated with the Non-U.S. Purchasers, even if Shell made those alleged misstatements (a separate subject not before the Special Master).

The unrefuted evidence shows that Shell communicated with the worldwide market from Europe, not from the United States. To the extent it addressed shareholders and analysts on a less global basis, Shell communicated with Non-U.S. Purchasers from Europe, not from the United States. Shell's communications in the United States were for the U.S. market, not for Non-U.S. Purchasers. The Non-U.S. Purchasers thus cannot rely on Shell's U.S.-based IR activities to satisfy the conduct test.

A. Shell's Global Communications About Proved Reserves

As discussed above in Section V, the United Kingdom and the Netherlands were the focal points for Shell's public-relations activities and dissemination of proved-reserves information. Shell's IR and External Affairs Departments were based in the United Kingdom and the Netherlands; Shell prepared and approved its proved-reserves disclosures in the United Kingdom and the Netherlands, and Shell reported its proved-reserves estimates to the worldwide market and the SEC from the United Kingdom and the Netherlands.

- The 4th Quarter and Full Year Results Announcements (the "4th Quarter QRA"), which first disclosed Shell's reserves replacement ratio ("RRR") for the prior fiscal year, always were prepared and released by Shell's IR personnel in London and The Hague.

- The press conferences accompanying the release of the 4th Quarter QRAs always were held in The Hague and/or London.
- The analyst presentations accompanying the release of the 4th Quarter QRAs always were held first (and usually only) in The Hague and/or London.
- The Annual Reports and SEC Forms 20-F, which contained Shell's proved-reserves estimates and RRR, always were prepared in and released to the markets, shareholders, and the SEC from The Hague and/or London.
- The periodic Group Strategy Presentations always were held first in London. Shell then repeated each presentation in the United States for the U.S. market. Shell's New York IR office did not play any role in preparing presentation materials about the EP business, which reports Shell's proved reserves.
- The EP Business Presentations always took place first (with one exception) in Europe. EP then repeated the presentations in the United States for the U.S. market. The materials and direct remarks for all presentations (including the New York ones) were prepared by IR personnel in London and The Hague.[110]

In addition, Shell communicated with the U.S. media through their London bureaus.

Thus, Shell always disclosed information about its proved reserves for the first time in and from Europe. Even in the single instance where an EP Business Presentation took place first in the United States before being repeated in Europe, no new information about proved reserves was released during that meeting. The chart in Section V of Shell's fact submission shows that Shell never disclosed new, previously unreleased information about its proved reserves, RRR, or Return on Average Capital Employed except in investor-relations releases or presentations issued from or held in Europe.

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[110] On very rare occasions, Shell allowed investors or analysts from outside the United States to attend presentations held in the United States if they had been unable to attend the corresponding presentation in Europe. At all other times, however, the audience for the United States presentations consisted of analysts and investors based in the United States.

B. Small-Group and Individualized Communications

Section V also showed that, to the extent Shell communicated with investors and analysts on other than a global basis, it communicated with Non-U.S. Purchasers outside the United States. Shell's U.S.-based IR activities were only for U.S. investors and analysts.

- The one-on-one meetings and "road shows" in the United States were for U.S.-based investors and analysts. No such meetings were held in the United States with European-based investors or analysts. Shell held separate meetings outside the United States for Non-U.S. Purchasers and analysts.

- Only one field trip was held in the United States during the Class Period, and that field trip focused primarily on Shell's oil-sands project in Canada and secondarily on Shell's downstream businesses in Houston, which do not have, estimate, or report proved reserves. The EP portion of that field trip was tertiary and short.

- The stand-alone presentations in the United States were for U.S. audiences. Shell held separate stand-alone presentations outside the United States for non-U.S. audiences.

Moreover, as Section V and the chart in Shell's fact submission demonstrate, Shell never disclosed new, previously unreleased information about its proved reserves during any of these small-group or individualized presentations and meetings. That information – which is what this case is about – was first released to the worldwide market in and from Europe.

The Non-U.S. Purchasers thus cannot prove that Shell communicated with them or with non-U.S. markets from the United States about anything relating to proved reserves.

C. No Flow-Back of Information from the United States to Other Countries

Because plaintiffs cannot show that Shell's U.S.-based IR activities were directed at Non-U.S. Purchasers, plaintiffs have speculated that Shell's IR activities in the United States might have flowed back indirectly to Non-U.S. Purchasers in their home countries. The record, however, does not support this conjecture – and certainly not to any meaningful extent.

First of all, as Section V illustrated, Shell's IR activities in the United States were minor in comparison to its IR activities outside the United States, and Shell always released proved-reserves information to the worldwide market in and from Europe. Thus, Non-U.S. Purchasers and non-U.S. markets were far more likely to have received and allegedly reacted to proved-reserves information released in and from Europe than to any repetitions of that information that might have reached them indirectly and later from the United States.

Second, Shell gave separate presentations and held separate meetings for U.S. and non-U.S. analysts and investors, so there is no reason to believe that Non-U.S. Purchasers received and allegedly relied on any information repeated at meetings that were not meant for them. The far more likely inference is that, to the extent Non-U.S. Purchasers obtained proved-reserves information from sources other than Shell's global disclosures (*i.e.*, 4th Quarter QRAs, press conferences, annual analyst presentations, Annual Reports, etc.), they did so from small-group and individualized meetings held for them outside the U.S., not from those held for a different audience across the ocean.

Third, investors in different countries had different attitudes toward investing and looked for different kinds of information. They did not rely on presentations made to other persons in other countries. Shell therefore tailored its nonglobal IR activities to suit the interests of its different groups of current and prospective investors.

The head of Group Investor Relations (Mr. Henry) testified that the United Kingdom, Continental Europe, and the United States were "very different markets in terms of the way companies communicated to the market, the type of concerns . . . investors in the market [had], and where they perceived value to be in a company."[111] For example, Mr. Henry explained that Continental European investors "tend to have what we would term a longer time frame" and "were very much focused on strategy and much less focused on quarterly results

111 Henry Dep. at 28:12-21.

. . . ."[112] Continental European investors compared Shell with European energy companies such as Total and BP.

U.S. investors, in contrast, "had their highest focus on the quarterly results and are much more analytical than European investors, so numbers mattered to U.S. investors more than [to] the European [investors] . . . ." In addition, "U.S. investors very rarely looked at the value of the business outside North America, and therefore any communications inside North America would have an element focused on our Business inside North America, a much greater element than our global presentations. So the U.S., while being important to our other investors, was just one country, whereas to a U.S. investor it's 'the' country, the domestic versus foreign split."[113] Thus, Mr. Henry said, "[q]uite frequently a third to 50 percent of the content [of stand-alone presentations in the U.S.] would focus on North American operations, whereas typically for a global presentation it may be somewhere from zero to 15 percent of the presentation, depending on the global investor concerns."[114] The U.S. investors also compared Shell primarily with U.S. energy companies such as Exxon, Chevron, Conoco, Texaco, and Phillips Petroleum, rather than with Total or BP.

Investors in the United Kingdom focused mostly on BP, because Shell and BP together constituted about 13% or 14% of the FTSE 100 Index. U.K. investors therefore had to "have an opinion on those two companies" and choose between them, to avoid overweighting

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112 Henry Dep. at 30:9-13.

113 Henry Dep. at 31:17-33:23.

114 Henry Dep. at 33:5-10.

their portfolios in one sector of the U.K. index. U.K. investors also had a shorter "time horizon" than did U.S. investors.[115]

Because of these differences in investor attitudes and concerns, "[r]esearch written in the U.S. rarely crossed the ocean . . . . Europeans rarely use[d] American analyst reports . . . . They use European research if they use research at all."[116]

Fourth, investors or analysts from outside North America very rarely communicated with the New York IR office at all. Some of those contacts occurred simply because of time-zone differences: at certain times, the London and The Hague IR offices were closed, but the New York office was still open. On other occasions, investors or analysts from outside North America contacted the New York IR office with specific questions about Shell's assets or operations in the United States, such as Shell's acquisitions of Texaco's downstream interests and the Pennzoil Quaker State Lubricants Company. Those questions about U.S.-based assets and operations, however, were unrelated to the proved-reserves issues in this litigation.[117]

Accordingly, information obtained in the United States about Shell's proved reserves generally did not flow back to non-U.S. investors in other parts of the world. Non-U.S. investors and analysts attended their own presentations outside the United States, communicated with IR personnel in Europe, and read European analysts reports (if any). The evidence also belies any argument that non-U.S. investors reviewed and relied on U.S.-based analysis and research.[118]

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115 Henry Dep. at 29:7-16, 31:21-25.

116 Henry Dep. at 151:3-10.

117 Sexton Decl. ¶ 10; Sexton Dep. at 45:15-46:16, 48:11-23.

118 Henry Dep. at 150:14-151:10.

FACT SUPPORT

XI. SHELL'S U.S. INVESTOR-RELATIONS ACTIVITIES

A. Shell's Global Communications About Proved Reserves

1. The United Kingdom and the Netherlands were the focal points for Shell's public-relations activities and dissemination of proved-reserves information.

    a) Shell's IR and External Affairs Departments were based in the United Kingdom and the Netherlands.

        (1) The factual support for this proposition is found in Section V.A. and Section V.B. *supra*.

    b) Shell aggregated, prepared, and approved its proved-reserves disclosures in the United Kingdom and the Netherlands.

        (1) The factual support for this proposition is found in Section V.C. *supra*.

    c) Shell reported its proved-reserves estimates to the worldwide market and the SEC from the United Kingdom and the Netherlands.

        (1) The factual support for this proposition is found in Section V.C *supra*.

    d) Shell always disclosed information about its proved reserves for the first time in and from Europe. Even in the single instance where an EP Business Presentation took place first in the United States before being repeated in Europe, no new information about proved reserves was released during that presentation. The chart in Section V. D. *supra* shows that Shell never disclosed information about its proved reserves, RRR, or Return on Average Capital Employed for the first time in the United States.

        (1) The factual support for this proposition is found in Section V.D. *supra*.

B. Small-Group and Individualized Communications

1. To the extent Shell communicated with investors and analysts on other than a global basis, it communicated with non-U.S. investors and analysts outside the United States. Shell's U.S.-based IR activities were only for U.S. investors and analysts.

a) The one-on-one meetings and "road shows" in the United States were for U.S.-based investors and analysts. No such meetings were held in the United States with European-based investors or analysts. Shell held separate meetings outside the United States for non-U.S. investors and analysts.

(1) The factual support for this proposition is found in Section V.C.10.(1) *supra*.

b) Only one field trip was held in the United States during the Class Period, and that field trip focused primarily on Shell's oil sands project in Canada and secondarily on Shell's downstream businesses in Houston, which do not have, estimate, or report proved reserves. The EP portion of that field trip was tertiary and short.

(1) The factual support for this proposition is found in Section V.C.10.(2) *supra*.

c) The stand-alone presentations in the United States were for U.S. audiences. Shell held separate stand-alone presentations outside the United States for non-U.S. audiences.

(1) The factual support for this proposition is found in Section V.C.10.(3) *supra*.

2. Shell never disclosed new, previously unreleased information about its proved reserves, RRR, or Return on Average Capital Employed during any of the U.S. one-on-one meetings, field trips, or stand-alone presentations that had not first been released to the worldwide market in and from Europe.

a) The factual support for this proposition is found in Section V.D. *supra*.

C. No Flow-Back of Information from the United States to Other Countries

1. The different characteristics of the three Shell investor markets.

a) Shell divided its investor base into three distinct markets – the United Kingdom, Continental Europe, and North America – and viewed each group separately.

(1) Henry

(a) "I was responsible for all of the communications to investors worldwide, across the three main investor markets, Europe, the U.K., and North America

. . . . We did look at the three markets separately. The three markets have different characteristics . . . . [E]ach market is different." (SEC Dep. pg. 16:20-22, 21:22-23, 24:13)

(b) "Q: Did that Global Strategy Plan make allowances for the different geographic regions you described in terms of presentation? By that I mean the United States, Continental Europe and the U.K. A: Yes, it did. Three very different markets in terms of the way companies communicated to the market, the type of concerns, the type of investors in the market, and where they perceived value to be in the company. . . ." (Dep. pg. 28:12-21)

b) The overall prices for Shell securities were most influenced by the London market in the United Kingdom, where the most influential opinion leaders concerning Shell traded and worked.

(1) Henry

(a) "The securities are primarily listed in London and Amsterdam, and the price for all of the securities associated with the Royal Dutch/Shell Group of companies is very firmly set in the London market. It is set there because that is where the major shareholders are, that is where the major trading takes place, that is where the major opinion-formers on the performance of the company in terms of the City of London and the research analysts sit. Shell and BP constitute then I think about something like 13, 14 percent of the FTSE Index, FTSE 100 Index. It's a similar percentage today but slightly higher today at unification. So any U.K. investor has to have an opinion on those two companies. Also, any investor who is making a choice about what they can invest in will not go long on both BP and Shell, because then they will be overweighted, overexposed to the U.K. Index. So not only was the price set in London, but it was very sensitive to issues between Shell and BP. It was very difficult for a long-term investor with a large holding to favor both companies, because it increased that portfolio risk and exposure to one industry. So that was clearly the focus, and the U.K. market would not just be on the strength of the company, but it would be on the issues that impacted people's perceptions of BP and Shell." (Dep. pg. 28:21-30:2)

(b) "While Royal Dutch and Shell Transport securities were traded in a number of markets, the overall prices for both securities were most influenced by the London market, where the most influential opinion leaders concerning the Group traded and worked." (Decl. ¶ 8)

c) Investors from Continental Europe were more focused on strategy and less focused on quarterly results than were other investors.

(1) Henry

(a) "Continental Europe investors tend to have what we would term a longer time frame, a longer, a mindset, a different mindset. They were very much focused on strategy and much less focused on quarterly results . . . ." (Dep. pg. 30:9-13)

d) Investors from the United States were more focused on quantitative data and on the U.S. side of the business than were other investors.

(1) Henry

(a) "U.S. investors had their highest focus on the quarterly results and are much more analytical than European investors, so numbers mattered to U.S. investors more than the European, and typically large U.S. investors have a longer time horizon than the U.K., and therefore you're always looking to appeal to people who will keep, buy and hold the stock for a significant period of time . . . . [T]here was also the issue that U.S. investors very rarely looked at the value of the business outside North America, and therefore any communications inside North America would have an element focused on our Business inside North America, a much greater element than our global presentations. So the U.S., while being important to our other investors, was just one country, whereas to a U.S. investor it's 'the' country, the domestic versus foreign split." (Dep. pg. 31:17-33:23)

(b) "Analysts and investors in Europe analyzed the Group differently from analysts and investors in the United States. Analysts in the United States were more focused on quantitative data and short-term results than were analysts in Europe. As a result, reports issued by United States-based analysts were rarely used by European investors to make investing decisions." (Decl. ¶ 9)

e) Thus, stand-alone presentations directed at U.S. investors and analysts had a greater focus on North American operations than did Shell's global presentations.

(1) Henry

(a) "Quite frequently a third to 50 percent of the content would focus on North American operations, whereas typically for a global presentation it may be somewhere from zero to 15 percent of the presentation, depending on the global investor concerns." (Dep. pg. 33:5-10)

f) The U.S. investors also compared Shell primarily with U.S. energy companies such as Exxon, Chevron, Conoco, Texaco, and Phillips Petroleum, rather than with Total or BP.

(1) Henry

(a) "Clearly our main competitors in the U.S. market in our own sector were Exxon, Chevron, Conoco, plus their various offshoots, Texaco Phillips. BP and Total are also competitors here, because they were an alternative investment for a U.S. investors who was interested in non-U.S.-based oil and gas companies . . . ." (Dep. pg. 31:25-32:7)

g) Despite the existence of three investor markets and three IR offices, consistent information about Shell was issued across the three investor markets.

(1) Sexton

(a) "Q: Did you speak to either the Investor Relations representative for the UK and/or Continental Europe to ensure that a consistent message was being – or consistent information was being disseminated with regard to Shell? . . . A: I would simply note that I didn't need to speak to him to ensure they had a consistent message. Due to the practices that were employed in the office, there was a consistent message. Q: Could you briefly describe those practices for me? A: There was information developed, presentations, questions and answers, briefing notes that were developed by the Businesses in conjunction with the Investor Relations Group to use in our work. And once those were developed, those were used by all three individuals that I referenced in our job." (Dep. pg. 41:12-17, 41:20-24, 42:2-11)

2. IR Presentations in the United States were directed at North American Investors and Analysts.

a) The various IR presentations and meetings that took place in the United States were held to discuss Shell's activities and strategy with North America-based analysts and investors. Shell's general practice was to invite investors and analysts based in North America to its presentations in the United States.

(1) Sexton

(a) "The various Investor Relations presentations and meetings that took place in the United States were held to discuss Shell's activities and strategy with United States-based analysts and investors, just as presentations and meetings in Europe were held to discuss Shell's activities and strategy with European analysts and investors." (Decl. ¶ 17)

b) On very rare occasions, Shell allowed investors or analysts from outside North America to attend presentations held in the United States if they had been unable to attend the corresponding presentation in Europe. At all other times, however, the audience for the U.S. presentations consisted of analysts and investors based in North America.

(1) Sexton

(a) "Our general practice in the country would be to invite U.S.-based analyst investors to that. On occasion, if someone outside the country could not for some reason attend their version of this event, we would allow them to come to the U.S. Similarly, if someone in the U.S. was not able to attend the U.S. event, they would be extended an invitation to the one outside the U.S." (Dep. pg. 89:25-90:8)

(2) Henry

(a) "On very rare occasions, an analyst or investor from outside North America was allowed to attend the United States conference, but, at all other times, the audience for the United States conference consisted of analysts and investors based in the North America." (Decl. ¶ 31)

c) Similarly, the one-on-one meetings in the United States were conducted almost exclusively with U.S.-based investors and analysts. Shell held separate one-on-one meetings outside the United States for analysts and investors based outside the United States.

(1) Henry

(a) "[T]hose one-on-one meetings that occurred in the United States were almost exclusively conducted with United States-based investors and analysts, who would presumably use the contents of those meetings to assist them in deciding or advising their United States-based clients whether to invest in Shell securities. No one-on-one meetings were held in the United States with European-based analysts or investors." (Decl. ¶ 38)

(b) "Each of these meetings was held to discuss the Group's activities and strategy with a United States-based analyst or investor, just as one-on-one meetings were held in Europe to discuss the Group's activities and strategy with European analysts and investors. In each case, the Group executive attending the meeting conveyed substantially the same messages and disclosed substantially the same information as had previously been disclosed to the market from Europe." (Decl. ¶ 40)

3. On very rare occasions, investors or analysts from outside North America contacted the New York IR office. Some of these contacts occurred simply because of time-zone differences: at certain times, the London and The Hague IR offices were closed, but the New York office was still open. On other occasions, investors or analysts from outside North America contacted the New York IR office with specific questions about Shell's assets or operations in the United States, such as Shell's acquisition of Texaco's downstream interests and the Pennzoil Quaker State Lubricants company. Those questions about U.S.-based assets and operations were unrelated to the proved-reserves issues in this litigation.

a) *See* Sexton Decl. ¶ 10, Sexton Dep. pg. 45:18-46:16, 48:5-23.

4. The evidence also belies any argument that non-U.S. investors reviewed and relied on U.S.-based analysis and research.

a) While large brokerage houses, such as Goldman Sachs and Merrill Lynch, typically had analysts who covered Shell based in both London and New York, the primary analyst for Shell coverage was always based in London. Moreover, the London-based analyst teams from these large brokerage houses brokered research into the European market, and the New York-based analysts did the same for the U.S. market.

(1) Henry

(a) "Q: Did any of the brokerage houses that follow Shell have only a single analyst who followed the companies? A: The large brokerage houses typically have two, with the prime always being in London for the Shell coverage, maybe not prime in terms of the Oil and Gas sector for that brokerage house, but the – if I look at Goldman's, Merrill Lynch, UBS, and Lehman Brothers, they all had a New York-based Oil and Gas team and they all had a London-based Oil and Gas team. The New York team brought research and sold it and brokered into the U.S. market, and the European Teams did the same for the European Team. Research written in the U.S. rarely crossed the ocean, because U.S.-based research, as I mentioned earlier, is entirely enumerate, and it's based on the last three months and the next three months. Europeans rarely use American analyst reports, so – that's what they told us anyway. They use European research if they use it at all." (Dep. pg. 150:14-151:10)

b) Smaller brokerage houses typically had analysts covering Shell based in only one location. For example, ABN Amro had a single analyst team, based in Europe, to cover Shell.

(1) Henry

(a) "The smaller houses would typically have one lead. Often they had a small team, one or two people, but in one location, so – and ABN had one team based in Europe. It was only maybe the top ten who would have a team in both countries." (Dep. pg. 151:17-22)

c) First Albany was another brokerage house that covered Shell. While First Albany was based only in the United States, it did not have any non-U.S. clients.

(1) Henry

(a) "Q: Do you recall if First Albany had any other analysts following Shell during Mr. Gilman's tenure there? A: No, they didn't. Q: Do you know if First Albany disseminates analyst reports? A: It disseminated them, I believe, to their U.S. customers, which were their only customers. They have no presence in Europe." (Dep. pg. 148:9-17)

d) Because analysts and investors in the United States analyzed Shell differently from analysts and investors in Europe, research reports written by U.S.-based analysts were rarely used by European investors.

(1) Henry

(a) "Analysts and investors in Europe analyzed the Group differently from analysts and investors in the United States. Analysts in the United States were more focused on quantitative data and short-term results than were analysts in Europe. As a result, reports issued by United States-based analysts were rarely used by European investors to make investing decisions." (Decl. ¶ 9)

e) European journalists did not contact Shell's External Affairs department with questions about matters raised at Shell presentations in New York.

(1) Jacobi

(a) "Q: Do you recall ever being asked a question by a journalist in Europe concerning issues that were raised at any of the analysts' conference conducted in New York? . . . A: I don't recall European journalists asking questions about matters raised in New York." (Dep. pg. 65:15-21)