Docket: 2003-705(IT)G

BETWEEN:

EXXONMOBIL CANADA LTD.,

Appellant,

and

HER MAJESTY THE QUEEN,

Respondent.

Appeal heard on common evidence with the appeal of Exxonmobil Canada Hibernia Company Ltd. (2012-1389(IT)G) on January 14 to 17, 2019, January 21 to 24, 2019 and January 28 and 29, 2019, at Calgary, Alberta

Before: The Honourable Justice John R. Owen

Appearances:

Counsel for the Appellant:	Gerald Grenon, David Jacyk and Brynne Harding
Counsel for the Respondent:	Rosemary Fincham, Suzanie Chua and Cédric Renaud-Lafrance

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JUDGMENT

WHEREAS, prior to the commencement of the hearing of this appeal, the parties settled a significant number of issues raised in the original Notice of Appeal filed by the Appellant;

AND WHEREAS the settlement of these issues was reflected in a Partial Judgment and Order issued by Justice Paris of this Court on March 5, 2018;

AND WHEREAS, at the commencement of the hearing of this appeal, the parties tendered a Partial Consent to Judgment dated January 13, 2019 that fully resolved issues 8, 9, 10 and 11 which were still under appeal;

AND WHEREAS the remaining issue under appeal is whether the Appellant's share of revenue earned from the sale of crude oil qualifies for the resource allowance under former paragraph 20(1)(v.1) of the *Income Tax Act (“*ITA*”)*;

NOW THEREFORE, in accordance with the attached Reasons for Judgment, the appeal from the reassessment made under the ITA for the taxation year ending November 30, 2000, notice of which is dated December 31, 2018, is allowed and the reassessment is referred back to the Minister of National Revenue for reconsideration and reassessment on the basis that no income was derived by the Appellant from transporting or transmitting petroleum.

Each party shall bear its own costs.

Signed at Ottawa, Canada, this 7th day of May 2019.

“J.R. Owen”

Owen J.

Docket: 2012-1389(IT)G

BETWEEN:

EXXONMOBIL CANADA
HIBERNIA COMPANY LTD.,

Appellant,

and

HER MAJESTY THE QUEEN,

Respondent.

Appeal heard on common evidence with the appeal of
Exxonmobil Canada Ltd. (2003-705(IT)G) on
January 14 to 17, 2019, January 21 to 24, 2019 and
January 28 and 29, 2019, at Calgary, Alberta

Before: The Honourable Justice John R. Owen

<u>Appearances</u>:

Counsel for the Appellant:	Gerald Grenon, David Jacyk and Brynne Harding
Counsel for the Respondent:	Rosemary Fincham, Suzanie Chua and Cédric Renaud-Lafrance

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<u>JUDGMENT</u>

WHEREAS, prior to the commencement of the hearing of this appeal, the parties settled two of the five issues raised in the original Notice of Appeal filed by the Appellant;

AND WHEREAS the settlement of these issues was reflected in a Partial Judgment issued by Justice Paris of this Court on June 13, 2017;

AND WHEREAS, at the commencement of the hearing of this appeal, the parties tendered a Partial Consent to Judgment dated January 13, 2019 that fully resolved issue 4 under appeal;

AND WHEREAS the remaining issues under appeal are whether revenue earned by the Appellant from the sale of crude oil qualifies for the resource allowance and whether the Appellant's share of the expenditure incurred to drill a well qualified as an expenditure for scientific research and experimental development;

NOW THEREFORE, in accordance with the attached Reasons for Judgment:

1. the appeal from the reassessment made under the *Income Tax Act* ("ITA") for the taxation year ending December 31, 2005, notice of which is dated March 4, 2010, regarding the resource allowance issue is allowed and the reassessment is referred back to the Minister of National Revenue for reconsideration and reassessment on the basis that no income was derived by the Appellant from transporting or transmitting petroleum; and

2. the appeal from the reassessment made under the ITA for the taxation year ending December 31, 2005, notice of which is dated March 4, 2010, regarding the scientific research and experimental development issue is dismissed.

Each party shall bear its own costs.

Signed at Ottawa, Canada, this 7th day of May 2019.

"J.R. Owen"

Owen J.

Citation: 2019 TCC 108
Date: 20190507
Docket: 2003-705(IT)G

BETWEEN:

EXXONMOBIL CANADA LTD.,

Appellant,

and

HER MAJESTY THE QUEEN,

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Docket: 2012-1389(IT)G

AND BETWEEN:

EXXONMOBIL CANADA
HIBERNIA COMPANY LTD.,

Appellant,

and

HER MAJESTY THE QUEEN,

Respondent.

REASONS FOR JUDGMENT

Owen J.

I. Introduction

[1] These are appeals by ExxonMobil Canada Ltd. ("EMCL") in respect of the reassessment of its taxation year ending November 30, 2000 by notice dated December 31, 2018, and by ExxonMobil Canada Hibernia Company Ltd. ("EMCHCL") in respect of the reassessment of its taxation year ending December 31, 2005 by notice dated March 4, 2010.

[2] Prior to the commencement of the hearing of these appeals, the parties settled a significant number of the issues raised in the original Notices of Appeal filed by EMCL and EMCHCL. The settlement of these issues was reflected, in the case of EMCL, in a Partial Judgment and Order of Justice Paris dated March 5, 2018, and in the case of EMCHCL, in a Partial Judgment of Justice Paris dated June 13, 2017.

[3] At the commencement of the hearing of these appeals, the parties tendered to the Court two further partial consents to judgment that addressed all but two of the remaining issues. I agreed to the partial consents to judgment and have incorporated the issues addressed in these consents in my judgment.

[4] As a result of the foregoing, the only two issues addressed at the hearing of these appeals were (1) the reassessment of EMCL to reclassify its $3,674,626 share of the revenue earned by ExxonMobil Canada Properties—a partnership of EMCL and ExxonMobil Canada Resources Company—from the sale of crude oil during its fiscal period ending December 31, 1999 as not qualifying for the resource allowance provided for in former paragraph 20(1)(v.1) of the *Income Tax Act* (the "ITA") and Part XII of the *Income Tax Regulations* (the "ITR") and the reassessment of EMCHCL to reclassify $530,138 of its revenue from the sale of crude oil during its 2005 taxation year as not qualifying for the resource allowance, and (2) the reassessment of EMCHCL to deny EMCHCL's claim that its share of the expenditure incurred in 2005 to drill well B16-54 qualified as an expenditure for "scientific research and experimental development" as defined in subsection 248(1) of the ITA (the "SR&ED Claim").

II. <u>The Facts</u>

[5] The parties filed a Partial Statement of Agreed Facts (the "PSAF") and a Joint Book of Documents (the "JBD"). Figures 1 to 5 of the PSAF are reproduced in Appendix A to these reasons and the text of the PSAF is reproduced below. For ease of reference, I will refer to the project located off the east coast of Newfoundland and Labrador involving the development and operation of the Hibernia oilfields as Hibernia.

[6] The Appellant called the following fact witnesses:

1) John Joseph Henley. Mr. Henley worked as a consultant to or an employee of Hibernia Management and Development Company Ltd. (HMDC), which operated Hibernia. From 2001 to 2006, Mr. Henley

was the president of Newfoundland Transshipment Limited ("NTL"), which owned the Whiffen Head Transshipment Terminal ("Whiffen Head") in Placentia Bay, Newfoundland. Mr. Henley's testimony addressed the resource allowance issue.

2) John Edward Eastwood. Mr. Eastwood is a geophysicist and seismologist who was the geoscience production manager for Hibernia and other nearby projects between 2003 and 2007. He described the role of the multidisciplinary team of 12 to 14 people that he supervised as characterizing the reservoirs, understanding the amount of reserves and developing the fields in the "most optimal" way possible. Mr. Eastwood left Hibernia in 2007.

3) Peter John Vrolijk. In 1989, Mr. Vrolijk joined what subsequently became known as ExxonMobil Upstream Research Company ("EMURC") as a researcher and remained with that company until he retired in 2016. EMURC undertook novel and, in many cases, proprietary research to obtain a competitive advantage in exploring for and producing oil and gas. EMURC also provided technical expertise to other corporations in the ExxonMobil group of companies.

4) Arslan Akhmetov. Mr. Akhmetov is a production geoscience supervisor with Imperial Oil in Alberta. The team that Mr. Akhmetov supervises looks after all geoscience efforts supporting the production of oil at Hibernia as well as at other production assets.

5) James Ridley Muir. Mr. Muir was a research and technology adviser with the Canada Revenue Agency (the "CRA") from 2004 until the beginning of 2009.

6) Chris Chiwetelu. Mr. Chiwetelu held the position of national technology sector specialist with the CRA commencing in 2000 and was involved in the CRA's review of the SR&ED Claim.

[7] In addition to the six fact witnesses called by the Appellant, the Appellant and the Respondent each called one expert witness. Doctor Fairchild testified for the Appellant and Professor Gringarten testified for the Respondent. Doctor Fairchild was qualified in the field of geology and geophysics and the development and use of reservoir connectivity analysis. Professor Gringarten was qualified in reservoir characterization, in particular reservoir connectivity analysis,

and in measurements in wells and their uses, in particular well test analysis of wireline formation tester data.

[8] I found all of the witnesses to be credible.

[9] The PSAF states the following:

> 1. Hibernia is an oilfield located in the North Atlantic Ocean about 315 kilometers east of St. John's, Newfoundland and Labrador, in 80 metres of water, which was operated by Hibernia Management & Development Corporation ("HMDC").
>
> 2. The Hibernia sandstones and the Avalon Sandstones are the two principal reservoirs in the Hibernia Field.
>
> 3. In 1965, Mobil Oil Canada Ltd. received an exploration permit and began oil exploration of the Grand Banks area offshore the Province of Newfoundland in 1966.
>
> 4. A discovery well was drilled in the Hibernia field in 1979 and completed in 1980.
>
> 5. On January 15, 1985, Mobil Oil Canada Ltd., Gulf Canada Resources Inc., Petro-Canada Inc., Chevron Canada Resources Limited, Chevron Canada Petroleum Limited, and Columbia Gas Development of Canada Ltd., entered into the Hibernia Joint Operating Agreement.
>
> 6. On February 11, 1985, the Government of Canada ("Canada") and the Government of Newfoundland and Labrador (the "Province") signed the Atlantic Accord Agreement ("Agreement").
>
> 7. The Agreement provided for the joint management and revenue sharing in respect of the oil and gas resources offshore Newfoundland and Labrador. It also agreed to establish the Canada-Newfoundland Offshore Petroleum Board (the "Board") to administer the relevant legislation.
>
> 8. The Agreement was to be implemented through mutual and parallel legislation.
>
> 9. On September 15, 1985, Mobil Oil Canada Ltd, on behalf of itself and the other participants in a joint venture respecting an offshore oil development in the Hibernia field, (subsequently referred to by the Board as the "Proponent") submitted an application consisting of the "Hibernia Benefits Plan" and the "Hibernia Development Plan".

10. On March 30, 1990, the Proponent submitted a plan entitled “Hibernia Development Plan Update” for the Board’s information (the “Update”). The Update described the Proponent’s then current interpretation of the geology and reservoir characteristics of the Hibernia field, and the changes in its intended approach and proposed facilities. The Board determined that the Update constituted a revised development plan that required Board approval.

11. The Proponent in its Update proposed to use an “offshore loading system (OLS)” consisting of a seafloor riser terminal, a flexible vertical riser, a subsea swivel and gooseneck, a subsurface buoy, and a flexible catenary riser. The system proposed by the Proponent was represented in Figure 6 of Decision 90.01.

12. On September 7, 1990, Mobil Oil Canada Properties, being a partnership of which Mobil Oil Canada Ltd. was a partner, Gulf Canada Resources Limited, Petro-Canada Hibernia Partnership, Chevron Canada Resources, and Hibernia Management and Development Company Ltd., entered into the “Hibernia Field Operating Agreement”. On March 24, 1993, the said agreement was amended by the “Hibernia Field Operating Agreement Amending Agreement”.

13. On September 7, 1990, Mobil Oil Canada Properties, being a partnership of which Mobil Oil Canada Ltd. was a partner, Gulf Canada Resources Limited, Petro-Canada Hibernia Partnership, Chevron Canada Resources, Hibernia Management and Development Company Limited, Mobil Oil Canada Ltd., Petro-Canada Inc., and Chevron Canada Resources Limited entered into a Hibernia Ownership and Unanimous Shareholders Agreement. On March 24, 1993, this agreement was amended by the “Amended and Restated Hibernia Ownership and Unanimous Shareholders Agreement”.

14. On November 10, 1990, Her Majesty the Queen in Right of Canada, Her Majesty the Queen in Right of the Province of Newfoundland, Mobil Oil Canada Properties (of which Mobil Oil Canada Ltd. was a partner), Chevron Canada Resources, Gulf Canada Resources Limited, and Petro-Canada Hibernia Partnership, entered into the “Hibernia Development Project Framework Agreement”. This agreement was first amended on January 30, 1992. The agreement was further amended on March 24, 1993 by the “Hibernia Development Project Framework Agreement Second Amendment Agreement”.

15. Prior to the construction of the OLS, there were studies done to determine how far out to put the OLS to protect both the tanker and the Hibernia Platform. One study was done by Nordco Limited for Mobil Oil Canada Properties, dated February 1990 (“Nordco Report”).

16. The Nordco report evaluated the manoeuvring and drift characteristics of the proposed Hibernia Tankers in determining the distance the crude loading systems should be from the Hibernia Platform. The report concluded that a separation distance of 2 KM was adequate and allowed sufficient time for the

stand-by vessel and tanker crew to regain control of the vessels in the event of a failure of the main engines while loading. The Nordco Report contained a recommendation that:

a. The separation distance between the platform and the loading system be 2.0 km or greater;

b. The tankers be excluded from manoeuvring within a 1.0 km radius around the platform.

17. The final decision was made by Hibernia Management. While it would have saved money to place the OLS as close as possible to the platform, the marine expert's decision was to put it two kilometres away from the platform.

18. On July 10, 1996, the Hibernia Management and Development Company submitted "The Amendment to the Hibernia Development Plan["] (the "Amendment"), for the Approval of the Canada-Newfoundland Offshore Petroleum Board.

19. The Board rendered its report, constituting its conditional approval of the Proponent's proposals, by Decision 97.01.

20. The Hibernia platform began production drilling and producing in 1997. The platform was designed for an average crude oil production rate over a year of 110,000 barrels of oil per day, and a maximum rate of 150,000 barrels per day. In 2003, the Board gave the Hibernia Management and Development Company Ltd. permission to increase its annual production rate to 220,000 barrels per day.

The Topsides

21. The Hibernia Platform includes topsides facilities which accommodate drilling, producing and utility equipment, and provide living quarters that can accommodate a steady-state crew of up to 278 people. The Topsides is composed of five super modules:

a. **M10 Process**: Gas and water are separated from the produced oil, and gas is then compressed for reinjection into the reservoir.

b. **M20 Wellhead**: Drilling operations occur within the Wellhead Module, upon which two mobile drilling derricks are mounted. The Hibernia Platform is designed to drill two wells at a time.

c. **M30 Mud**: Drilling muds are pumped down the drill pipe and through holes in the drill bit to cool the bit, prevent the hole from collapsing and wash the cuttings away from the bottom of the hole. The muds are produced and conditioned in the Mud Module.

d. **M40 Utilities**: The Utilities Module contains various equipment required for power generation, heating, ventilation and air conditioning and water distribution.

e. **M50 Accommodations**: The Accommodations Module houses the eating and sleeping quarters for people working offshore, as well as offices and meeting areas. The Accommodations Module also contains the temporary safe refuge (TSR) in the event of an emergency. The TSR provides emergency power, radio communications and medical facilities. Also located here is the main lifeboat station, helideck and Selantic Skyscape evacuation system.

The Gravity Base Structure

22. The Topsides is supported by the GBS, a massive concrete pedestal, which sits on the ocean floor and is 111 metres high.

23. The GBS itself has a specially-designed and reinforced 15-metre thick ice wall that protects the inner storage cells. The Hibernia Platform can withstand the impact of a multi-million tonne iceberg, although typically the icebergs in the area are smaller, ranging from 50,000 to 300,000 tonnes.

The Offshore Loading System

24. The OLS is a network of lines[1] (sometimes referred to as “flow lines” or “pipelines” or “loading lines” in certain documents) that offloads oil from the Hibernia Platform onto large shuttle tankers. The loading system consists of two subsea loading lines, each extending 2 kilometres from the platform to north and south loading bases, respectively. A vertical riser at each base is then connected to a subsurface buoy that supports flexible loading hoses. At the end of each loading hose is a coupling head for attachment to the tankers. There is also an interconnecting line between the two bases.

25. The loading lines form a loop that allows crude oil to flow from the platform to a shuttle tanker connected to either OLS system. The loop allows the system to be flushed with seawater due to a potential iceberg event. In further detail, the Offshore Loading System includes:

a. **Main Offshore Line North and Main Offshore Line South**: The sub-sea lines come out from the bottom of the GBS. They are made of steel and welded and they connect onto the OLS riser bases, being the OLS Base North and the OLS Base South (collectively,

[1] The terminology of “lines” or “line” or “loading line”, as it appears in the Partial Statement of Agreed Facts, does not constitute an admission that this is the correct terminology with regard to the OLS, which is a matter in dispute between the parties.

the “OLS Bases”). These subsea lines each extend for 2 kilometers and are 24 inches in diameter. The layout of the OLS and subsea lines is depicted in the diagram attached hereto as Figure 1.

b. **Interconnecting Offshore Line**: There is a 400 metre interconnecting line between the OLS Bases which may be used to recirculate the subsea lines with seawater in the event of an iceberg. A very large iceberg may pose a risk of damage to the lines and, if the lines held crude oil, may create the risk of a leak. Consequently, once an iceberg comes within a certain distance of the platform, the platform operations would displace the crude oil in the subsea lines with seawater, thus returning the crude oil to the storage cells on the GBS.

c. **OLS**: The OLS is represented in the two diagrams attached hereto as Figure 2 and Figure 3.

   i. **OLS Base**: Figure 2 is a drawing of a riser base, which is a steel base with four pile cones. The OLS Bases are piled into the sea floor by a long piece of steel pipe which locks them in. At one end of the OLS Base is where one of the loading lines connects in and at the other end is where the other line, via the Interconnecting Offshore line, connects in. There is a valve to allow the Hibernia Platform to isolate one OLS from the loading lines if needed, while the other OLS would function. In the middle of the OLS Base is the male part of a hydraulic connector which will latch the bottom part of the Riser Foot.

   ii. **OLS Riser System**: Figure 3 is a drawing of the OLS (Riser System). The Riser System has a 19 inch diameter flexible pipe which connects to the Riser Foot and includes the Swivel/Gooseneck assembly which allows the upper part of the Riser System to rotate 360 degrees around the vertical part of the Riser System. A subsurface buoy holds the 19-inch flexible pipe vertical. Attached thereto is the Catenary Riser, consisting of a lower and upper part. Separating these parts is an in-line swivel that allows the Catenary Riser to swivel on itself as the tanker is rotating around in the weather. At the end of the Catenary Riser is a Coupling Head.

   iii. **Pick-Up Arrangement**. Figure 4 attached hereto depicts the OLS Riser in Operating and Idle Conditions. A tanker connects to the OLS by having a standby vessel pick-up a nylon floating line that is attached to a subsurface float.

> The standby vessel then shoots a line up to the bow of the tanker. The tanker takes that line, hoists it in, and puts it on a traction winch and drags the vertical catenary riser up off the sea floor onto a receptacle in the bow of the tanker. The coupling head is at the end of the catenary riser. During loading, the OLS Riser Coupling Head will be connected to the tanker coupler. Integrated in the OLS Riser Coupling Head is the main OLS riser system isolation valve, which is a spring operated spindle type, which is fail safe close [*sic*]. It is opened by the tanker after it is securely connected. The Hibernia Platform then pumps crude oil from the storage cells to the tanker through the coupling head at a rate of 53,000-55,000 barrels an hour.

26. Both the Hibernia Platform and the tanker are equipped for an emergency shut-down. In particular, the tanker possesses a control system which communicates with the control system of the Hibernia Platform through a telemetry link. The telemetric monitoring of operations between the tanker and the Hibernia Platform is referred to as the “Green Line”. If the “Green Line” is broken, the pumping and transfer of crude shuts down within 30 seconds: the OLS riser system isolation valve on the Coupling Head closes at a certain speed allowing for the momentum of the crude in the line to slow down to avoid a shock to the OLS system.

27. Forces generated by wind, current and wave action on the tanker are counteracted by the dynamic positioning system installed on the tanker. The shuttle tanker’s bow thrusters and main engines keep the tanker bow within the approved operating radius for the OLS system. If there is a problem with the tanker’s position system, there is a risk that the tanker, in trying to adjust for weather, drives off or adds too much power. If the tanker bow moves out of the allowed radius due to wind and wave forces, the shuttle tanker stops the crude loading pumps and if the excursion is extreme, drops the loading system hose. This protects the system and the environment. The shuttle tankers are large vessels and it takes time for their position to change in response to the thrusters and main propulsion system.

28. There is also a risk that a tanker may lose power. On each tanker there is an emergency towing houser [*sic*] as required by the International Maritime Organization. If the tanker loses power, its crew would throw this emergency towing equipment into the water, where it would be picked up by a standby vessel. The standby vessel would then tow the tanker out of the Platform’s path. This takes time, and may require at least 30 minutes.

29. In either instance of a tanker driving off or losing power, there is a risk that a tanker will head towards the Hibernia Platform. The tankers are very large

vessels measuring 275 metres long and 50 metres wide. They weigh 155,000 dead weight tons and can hold 127,000 dead weight tons of crude oil. They are much bigger than the Hibernia Platform, the diameter of which is 102 metres.

30. Were a tanker to hit the Hibernia Platform, it would not destroy the platform which is designed for a very large impact by icebergs. Rather, the risks are that:

a. the tanker would be damaged with the potential for a fire;

b. if the tanker had crude on board, there would be a potential of an oil spill which would be a major environmental issue; and

c. due to the height of the tanker, it could hit the topsides of the lifeboat stations and other pieces of the Hibernia Platform that overhang the outer wall of the GBS; this could damage the Platform and precipitate a fire or explosion on the Platform. The 2 km distance of the OLS bases from the Hibernia Platform is to provide time for the shuttle tanker and support vessel to divert the tanker away from the platform.

31. To address the environmental conditions and for safety purposes, the shuttle tankers are ice reinforced, double hull vessels with segregated cargo and ballast tanks. The shuttle tankers are equipped with two propellers driven by separate diesel engines, two high performance rudders and two bow thrusters, to ensure maximum maneuverability and to minimize the possibility of an oil spill.

The pathway of the crude from the reservoir to the market

32. Crude oil and natural gas wells are prepared for production through a process called well completion.

33. Drilling operations on the Hibernia Platform occur within the Wellhead Module, and the two drilling modules which are located on tracks above the Wellhead Module. During drilling operations, a drill bit drills the well into the ocean floor. The drill pipe and casing pass through a slot, being a hole in the Platform’s base, on its way to reaching the drilling target beneath the ocean floor.

34. The crushed rock and stone produced by a drill bit are called drill cuttings. The cuttings are removed from the well by drilling mud, a compound of water or synthetic oil, clay and other chemical additives that are mixed together inside the Mud Module. Drill cuttings are disposed of by either discharging them in the ocean, in compliance with regulatory guidelines, or by injecting them back into the ground.

35. After the well has reached the desired depth and location, steel tubes called “production casings” or simply “casings” are run into the well and cemented. The casings line the total length of the well bore to ensure safe control of the crude oil and natural gas, to prevent water entering the well bore and to keep rock formations from sloughing into the well bore.

36. Once the cement has set, the production tubing can be put in place. The production tubing is lowered into the casing and hung from a sea floor installation called the wellhead. A “Christmas tree” is installed on the top of the wellhead that has remotely operated valves and chokes that allow the production operator to regulate the flow of oil and natural gas.

37. The production casing is then perforated to allow crude oil and natural gas to flow into the well. This is done by placing tiny explosive charges in assemblies, which are then lowered into the bottom of the well where they are detonated before recovering the assemblies back to surface. The charges make small holes through the casing, which allows the oil, gas and water to flow into the well bore.

38. The well is now ready for production.

39. The pressure of the reservoir forces the fluid from the reservoir through the well to the wellhead located on the Hibernia Platform.

40. The mixture composed of gas, hydrocarbons and water, sometimes referred to as “well fluid”, is brought up above ground through the production tubing into the Christmas tree, which controls the production from the well.

41. At the end of the Christmas tree, there is a mixture of the same thing that came out of the reservoir: that is, a mixture of gas, hydrocarbon, and produced water. The mixture then enters into the process train.

42. In the early stages of production, the fluid coming up from the reservoirs contains mostly crude oil, with some natural gas. As production continues and the reservoir becomes depleted, more gas and eventually water are recovered with the oil.

43. The well fluid next proceeds through the separators. Separating the natural gas and water allows the crude to be transported safely. This occurs inside the Processing Module on the Hibernia Platform.

44. In particular, the wells produce a mixture of gas, oil and water from the reservoir. Produced gases include methane, ethane, propane, and butane; these gases will vaporize at standard conditions and could explode under certain circumstances. Therefore, the gases must be removed during the separation process. The well fluids enter the separators which allow the gas to rise to the top and the crude oil to float on the produced water.

45. The well fluids go through three separators: they first pass through a high pressure separator, then a medium pressure separator, and finally a low pressure separator.

46. The processing has to be done in stages because the well pressures flowing to the Hibernia Platform are very high. At each separation stage, gas is removed to reduce the pressure. Water is also removed by the medium and low-pressure separators. This separation process produces "stabilized crude oil" which can be stored in the storage cells. Stabilized crude oil exists where the crude oil vapour pressure is lower than atmospheric pressure. The stabilization process prevents gases boiling off at atmospheric conditions which could ignite and/or explode.

47. Water that is removed from the crude by the separators is treated to reduce residual oil content to below or at levels that are considered to be protective of the environment as prescribed by government regulation prior to being released to the sea. The treated water is monitored on a regular basis to verify the release is conducted in accordance with regulatory requirements.

48. Produced gas, except for that which is used as fuel on the platform, is also intended to be injected into the reservoir for three reasons:

a. To minimize flaring, which will only occur for safety reasons;

b. To conserve the gas for potential extraction at a later date;

c. To provide pressure support to increase recoverable reserves in certain areas of the field.

49. After the separators, there remains a mixture of crude oil which originated from the well fluids retrieved from the Hibernia sandstone and Avalon sandstone. Because the components of the substances in the two reservoirs are different, the resulting crude oil produced and processed on the Hibernia Platform is referred to as "Hibernia blend".

50. At the end of the three separators, the crude oil has been stabilized and it is put in storage in the GBS.

51. The GBS contains storage space for approximately 1.3 million barrels of oil, in four groups of storage cells located within the GBS.

52. When a tanker arrives, the Hibernia Platform pumps the crude oil from the storage cells through the two-kilometre subsea loading lines, onto the tanker.

53. The crude oil is jointly owned by the joint venturers until it reaches the OLS coupling flange at the tanker. Once the crude gets on the tanker, it is the property of one of the joint venturers.

54. Attached as Figure 5 is an illustration of the operations carried out on and around the Hibernia platform.

55. A Lifting Agreement between the joint venturers was entered into.

56. Crude oil, including the "Hibernia blend" cannot be sold as an end product but can be sold to a third party refiner without further processing. Crude oil is priced on how much gasoline, jet, diesel and heating fuel can be made from it. The components of a crude oil vary depending on the reservoir from which it is produced. Refiners often buy different crude oils in order to create an optimum mixture of crude oils for the type of equipment they have in their refinery.

57. A Hibernia joint venture participant may sell their crude oil either:

a. Direct to Market: In this instance, the joint venture participant sells the crude oil to a third party without storing it at a transshipment terminal. Upon sale to the third party, the crude oil may go directly to a refinery or storage before being refined.

b. Transshipment Terminal: Transshipment is part of [a] two stage transportation process by a joint venture participant for moving crude oil to market. The joint venture participant takes the crude oil from the Platform and stores it at an intermediate storage location before it is sold to a refinery. It can be transshipped anywhere. Transshipment has two advantages: it minimizes the number of sophisticated shuttle tankers required to remove crude from the platform and allows the crude owner to use another tanker to sell the crude to the highest buyer.

58. At all material times, ExxonMobil Canada Hibernia Company Ltd.'s principal business was the exploration for, and the production of, petroleum, natural gas and other hydrocarbons.

59. As at December 31, 2005, ExxonMobil Canada Hibernia Company Ltd. was a wholly owned subsidiary of ExxonMobil Canada Resources Company ("EMCRC"), which was a wholly owned subsidiary of ExxonMobil Canada Ltd ("Exxon").

60. ExxonMobil Canada Limited and ExxonMobil Canada Resources Company are partners of ExxonMobil Canada Properties, a partnership created under the laws of Alberta.

61. ExxonMobil Canada Limited owns [a] sixty percent (60%) interest in ExxonMobil Canada Properties and ExxonMobil Canada Resources Company owns forty percent (40%).

62. The fiscal period of ExxonMobil Canada Properties ends on December 31st.

63. ExxonMobil Canada Properties and ExxonMobil Canada Hibernia Company Ltd. are parties to a contract commonly referred to as a joint venture contract and known as Hibernia.

64. ExxonMobil Canada Properties' and ExxonMobil Canada Hibernia Company Ltd.'s participation in Hibernia equals 28.125% and 5% respectively.

65. The Minister reclassified the amount of $3,674,626 of the resource revenue reported by ExxonMobil Canada Properties to non-resource revenue and reassessed ExxonMobil Canada Limited's 2000 taxation year accordingly. Similarly, in reassessing ExxonMobil Canada Hibernia Company Ltd.'s 2005 taxation year, the Minister reclassified $530,138 of its resource revenue as non-resource revenue.

66. In the adjustment prepared in support of its reassessment, the Minister stated: "To arrive at the value of production revenue at the GBS, the costs of the OLS have to be deducted. Using an accounting method that includes depreciation and return on capital (similar to the G3 method used to estimate gas plant profits), we have calculated total costs for the OLS. The partnership's proportionate share of these costs would reduce Resource Profits." The calculations, including the partnership's proportionate share, were set out in a spreadsheet entitled "Offshore Loading System (OLS)".

67. Neither party takes the position that, if amounts other than nil are properly treated as non-resource revenue respecting the OLS, different amounts other than those reassessed by the Minister as related above would be correct.

68. The Hibernia field has a complex landscape, with complex reservoir "plumbing" relationships.

69. Reservoir Connectivity Analysis ("RCA") is a systematic and logical approach for evaluating how a reservoir is connected.

70. During the 2005 taxation year, HMDC further developed RCA by incorporating state of the art 3D visualizing software used to predict the fluid type, fluid contact depth, and fluid pressures in the Hibernia reservoir. ExxonMobil Canada Hibernia Company Ltd. claimed for income tax purposes, that the following work for RCA resulted in scientific and technological advancements, which was accepted by the Minister for the 2005 taxation year:

i) integration of aquifer data at regional and field scales;

> ii) study of the role of intermediate structural blocks in dual fluid separation;
>
> iii) gravity segregation of oil;
>
> iv) integration of RCA prediction as first-order predictor to focus Direct Hydrocarbon Indicator studies; and
>
> v) visualization using Petrel 3D models to evaluate plausible connections and spill/breakover points.

> 71. HMDC paid a total of $40,964,305 to Noble Drilling, ABB Vetco, Swaco, Weatherford, Halliburton, Schlumberger as costs for drilling Bl6-54MM well in the 2005 taxation year. ExxonMobil Canada Hibernia Company Ltd.'s share of the aforesaid costs was $2,048,215 for the 2005 taxation year.
>
> 72. The Minister disallowed ExxonMobil Canada Hibernia Company Ltd.'s claim for qualified SR&ED expenditures of $2,048,215, which was its share of the aforesaid total cost for drilling Bl6-54MM well in the 2005 taxation year.
>
> 73. ExxonMobil Canada Limited and ExxonMobil Canada Hibernia Company Ltd. are large corporations within the meaning of the *Income Tax Act*, R.S.C. 1985, c. 1 (5th Supp.) as amended (the "*Act*").
>
> 74. The Minister of National Revenue (the "Minister") reassessed ExxonMobil Canada Hibernia Company Ltd. by notice dated March 4, 2010 for the taxation year ending December 31, 2005.
>
> 75. ExxonMobil Canada Hibernia Company Ltd. filed a notice of objection on June 1, 2010 (the "Notice of Objection").
>
> 76. ExxonMobil Canada Hibernia Company Ltd.'s appeal is made pursuant to ss. 169(1) of the Act.

[10] The stabilized crude oil produced at Hibernia (hereinafter, the "crude") is loaded onto one of three[2] shuttle tankers using the OLS. The shuttle tankers transport the Hibernia crude either directly to market—typically, one of several refineries in the northeastern United States—or to Whiffen Head. Crude stored at Whiffen Head is subsequently shipped to refineries on standard oil tankers. The owner of Whiffen Head does not acquire ownership of the crude stored at the facility.

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[2] Initially, there were two shuttle tankers. The third shuttle tanker was added in 2001 or 2002. Lines 19 to 24 of page 136 of Volume 1 of the transcript of the appeals of the Appellants heard in the city of Calgary on January 14 through January 29, 2019 (the "Transcript").

[11] The OLS has two locations for loading crude onto the shuttle tankers—one is referred to as the north base and the other is referred to as the south base. The two bases are each located approximately two kilometres southeast of the Hibernia platform and are each connected to the Gravity Base Structure ("GBS") by a 24-inch pipe (referred to by Mr. Henley as a "loading line") (Figure 1 of the PSAF). Two kilometres was chosen because it was the minimum distance that satisfied all safety and environmental concerns.[3] The prevailing currents and weather dictated the direction—if a shuttle tanker lost power it was more likely to drift away from the platform.

[12] Each OLS base is connected to the other OLS base by the interconnecting offshore pipeline ("IOP"). A riser supported in part by a subsurface buoy runs from each OLS base to a coupling head that attaches to the shuttle tanker. When not in use, a portion of the riser and the coupling head rest on the sea floor. The detailed components of the OLS are illustrated in Figures 2, 3 and 4 of the PSAF.

[13] When the OLS is in use, crude flows from the storage cells in the GBS through the loading lines to each OLS base. The crude that arrives at the base not being used to load the shuttle tanker then flows from that base to the other base through the IOP. The system is designed this way so that in the event of a threat to the loading lines, for example from icebergs scraping the sea floor, water can be flushed through the system to return the crude to the storage cells so that a rupture of the loading lines will not result in an oil spill. The loading lines are always filled with either water or oil to ensure that the pressure in the loading lines is similar to the pressure outside the loading lines.

[14] The crude stored in the storage cells in the GBS is jointly owned by the Hibernia joint venture owners until it reaches a shuttle tanker. At that point, it becomes the property of one of the joint venture owners (or its designated affiliate) in accordance with the Hibernia OLS Lifting and Transportation Agreement made as of the 1st day of November 1997 (Tab 61 of the JBD). A bill of lading is issued to reflect the transfer of ownership.

[15] The owner of the crude subsequently sells it to a refinery, which refines the crude into gasoline, jet fuel, diesel and heating oil. The crude purchased by the refinery is priced to reflect how much of these components is contained in the crude. The use of the OLS to load the shuttle tankers does not add value to crude.

[3] Lines 12 to 18 of page 120 of Volume 1 of the transcript.

However, the OLS does allow the joint venture owners to realize the value of that crude by transporting it to market (i.e., to refineries that can process the crude).[4]

[16] The storage capacity of the storage cells in the GBS (1.3 million barrels of crude) and the capacity of each shuttle tanker (850,000 barrels of crude) meant that a shuttle tanker must be loaded every 5.5 to 6 days. If the crude stored in the storage cells exceeded 1 million barrels then production would have to be reduced, which would result in a loss of revenue on a net present value basis.

[17] In the upstream sector, Exxon Mobil is organized into four groups of companies: exploration companies that explore for oil and gas, development companies that develop oil and gas assets, production companies that produce oil and gas, and a research company. The research company—ExxonMobil Upstream Research Company—performs basic and applied research in support of the activities of the other three companies to provide them with a competitive advantage.

[18] Oil companies use a variety of techniques to determine the existence, location and extent of oil within a given area. Once an oil reservoir is identified, the process that oil companies follow to develop the reservoir is known as reservoir management. The first step in reservoir management is reservoir characterization, which is aimed at developing a model of the reservoir. Reservoir connectivity analysis is in turn a part of reservoir characterization in that it contributes to the construction of the reservoir model. Professor Gringarten opines that all oil companies use some form of reservoir management.[5]

[19] The relative densities of natural gas, oil and water are such that when all three are present in an oil reservoir, the gas sits on top of the oil, the oil sits below the gas and on top of the water and the water sits below the oil. Where the oil contacts the water is called the oil-water contact or OWC.

[20] If the pressure at specific depths of the oil and of the water is known, the oil-water contact can be determined using a graph that plots the known and extrapolated oil and water pressures against depth. The point at which the resulting lines on the graph intersect is the oil-water contact. If the pressure at specific depths of the oil and of the water can be accurately predicted, then the oil-water contact can also be accurately predicted.

[4] Lines 27 to 28 of page 119 and lines 1 to 7 of page 120 of Volume 1 of the Transcript.
[5] Expert Opinion of Alain C. Gringarten dated October 8, 2018 (the "Gringarten Report"), at Volume 1, page 15.

[21] An oil producing well is drilled to the top of the oil level, a water injection well is drilled to the top of the water level and a gas injection well is drilled to the top of the gas level.

[22] The Hibernia oilfield is divided into "blocks" that are identified with letters or letters and numbers. Normally, a block is an area within an oilfield that is bounded by faults and requires distinct producer and injection wells to extract oil from that block.[6] One graphic illustration that shows blocks in the Hibernia oilfield is found at page 11 of Tab 5B of the JBD.[7]

[23] From a geologic perspective, the southern extension of the Hibernia oil field consists of blocks DD, Z, AA1, AA2, GG1, GG2, KK, LL, MM and NN.[8] As of the end of 2005, only blocks DD and Z had wells drilled in them.[9]

[24] The pressure of the water or of the oil in a block may or may not be the same as the pressure of the water or of the oil in an adjacent block. If the fluid in one block is "communicating" with the same fluid in an adjacent block then the pressure of that fluid in each block will be in equilibrium. Communication is the process whereby a fluid moves from one block to the other. The movement may be miniscule and take place over hundreds of thousands of years (large time scales are known as geologic time).[10]

[25] Prior to 2005, the decision was taken to develop the DD block of the Hibernia oil field, and two development wells were drilled into that block—an oil producer well and a water injection well. The oil producer well was drilled first and showed higher oil pressure than existing data and legacy interpretation techniques would have led one to expect. In early 2005, the water injector well (B16-50) was drilled down to 4,330 metres below the seabed, where water was expected in light of existing pressure data and legacy interpretation techniques. However, the water injection well showed only oil on rock at that depth (i.e., there was oil down to at least 4,330 metres below the seabed).[11]

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[6] Lines 23 to 28 of page 180 and lines 1 to 3 of page 181 of Volume 1 of the Transcript.
[7] There are many diagrams in Tab 5B and elsewhere in the JBD showing the blocks.
[8] Lines 3 to 11 of page 49 of Volume 2 of the Transcript.
[9] Lines 12 to 27 of page 49 of Volume 2 of the Transcript.
[10] See, generally, Section 2 of the Expert Report of Dr. Lee H. Fairchild dated October 19, 2018 (the "Fairchild Report") commencing on page 4, and pages 20 to 24 of the Gringarten Report.
[11] Lines 9 to 28 of page 15, lines 1 to 12 and 26 to 28 of page 16, lines 1 to 12 of page 17 and lines 13 to 22 of page 96 of Volume 2, and lines 27 to 28 of page 74 and lines 1 to 9 of page 75 of Volume 5 of the Transcript. Data from the well was obtained in February 2005: lines 14 to 19 of page 46, lines 6 to 14 of page 73, lines 12 to 28 of page 74 and lines 1 to 9 of page 75 of Volume 5 of the Transcript.

[26] The work on the RCA in issue in these appeals started with a one-week meeting convened by Doctor Vrolijk in early January 2005 that defined the scope of the project and predicted a result for the B16-50 well, which was being drilled at the time. A second one-week meeting was held in February, at which point the results from the B16-50 well were available. The results supported the prediction that had been made at the January meeting. This led to the detailed investigation of a new RCA modelling theory.[12] The components of the investigation are described in general terms in paragraph 70 of the PSAF.

[27] EMCHCL claimed its share of the expenditures incurred in respect of the RCA investigation as SR&ED expenses and the Minister allowed the expenditures as such. The new/improved RCA approach predicted that the oil-water contact in the blocks located in the southern extension of the Hibernia oilfield (the "Hibernia southern extension") could occur as deep as 4,800 metres, this being based on a predicted common oil pressure among blocks DD, Z, AA1, AA2, GG1, GG2, KK, LL, MM and NN[13] and a common near-hydrostatic aquifer.[14] Prior to the RCA predictions in 2005, no one had predicted significant oil in the Hibernia southern extension below the previously predicted 4,000 metre oil-water contact.[15]

[28] The location of the B16-54 well was chosen because it required the least drilling (i.e., shortest well length) to obtain the sought-after data.[16] To obtain permission to drill well B16-54 as well as authorization for the funding, a presentation was prepared for management.[17] Slide 2 of the presentation, titled "Management Summary", states:

SCOPE

[12] Lines 18 to 28 of page 29, lines 1 to 4 of page 30, line 28 of page 63 and lines 1 to 12 of page 64 of Volume 2 and lines 4 to 28 of page 42, pages 43 and 44, lines 1 to 4 of page 45, lines 14 to 19 of page 46, lines 6 to 26 of page 73 and lines 5 to 18 of page 74 of Volume 5 of the Transcript and Tab 49 of the JBD.

[13] Tab 42 of the JBD at slides 6 and 13 and lines 8 to 18 of page 46 of Volume 2, lines 24 to 28 of page 79, page 80 and lines 1 to 25 of page 81 of Volume 5 of the Transcript. The oil pressure in block DD was determined by the oil producer well in that block. In addition, as of June 16, 2005, there was a single producer well in block Z: lines 24 to 28 of page 52, lines 1 to 3 of page 53, lines 27 to 28 of page 70, lines 1 to 7 of page 71, lines 23 to 28 of page 96 and lines 1 to 25 of page 97 of Volume 2 of the Transcript, slides 6 and 13 of Tab 42 of the JBD, and slides 4, 5 and 6 of Tab 5A of the JBD.

[14] Water pressure is hydrostatic if the pressure of the water at the point of measurement reflects the weight of the water above that point.

[15] Lines 2 to 12 of page 189 of Volume 2 and lines 11 to 15 of page 122 of Volume 5 of the Transcript.

[16] Lines 9 to 28 of page 56, pages 57 to 59, lines 1 to 26 of page 60 and lines 14 to 24 of page 138 of Volume 2 and lines 12 to 28 of page 119 and lines 1 to 12 of page 120 of Volume 5 of the Transcript and slide 14 of Tab 41 of the JBD. The document at Tab 41 was prepared for the CRA and is dated March 18, 2010.

[17] Tab 42 of the JBD.

- Drill and abandon a 8175 m (27000 ft) MD near field wildcat (NFW) in the Hibernia MM block for a total cost of C$43.1 M (AFE).

- NFW MM1 will be immediately sidetracked to the OPGG1 location. The GG1 block development is being brought forward concurrently as a separate funding decision.

- Scheduled spud date for NFW MM1 is July 2005 from the East rig.

PRIMARY OBJECTIVES

- Define OWC in Hibernia South by penetrating primary reservoir targets of Layers 2 and 3 between 4500-4800 m (14764-15748 ft) TVDss - tests deepest possible contact.

- De-risk sufficient volumes to determine economic viability of platform facility upgrades and/or an 11 well subsea water injection development.

- Obtain core and fluid samples to characterize reservoir properties with depth to optimize future developments.

INCENTIVES

- The incremental risked STOOIP capture of NFW MM1 is 170 MB in up to 6 fault blocks.

- The risked unit development cost of the Hibernia South development is C$4-5/B.

- Fulfills EL 1093 commitment of C$8 M.

ISSUES

- Depth of OWC in Hibernia South is currently unknown but NFW MM1 will test interval of 4500-4800 m (14764-15748ft) TVDss. RCA and data from MM NFW derisks Hibernia South explicitly.

- Magnitude of potential reservoir quality (permeability and porosity) degradation with depth will be better understood through log and core acquisition.

[29] Chevron, one of the owners of Hibernia, raised concerns regarding the drilling of well B16-54. These concerns were addressed in an e-mail dated June 28, 2005 from Mark P. Evans, the reservoir manager for Hibernia, to

Paul Gremell of Chevron. The e-mail was in response to an earlier e-mail from Mr. Gremell to Doctor Eastwood and Mark P. Evans and was copied to Doctor Eastwood, who stated that he contributed to the creation of the e-mail.[18]

[30] In response to Mr. Gremell's concern that the B16-54 well was not the optimal first well into the Hibernia southern extension, Mark Evans states:

> The MM NFW is positioned to de-risk the oil-water contact for all of the Hibernia South fault blocks (excluding EE). Our analysis has leveraged expertise not only internal to HMDC but also from ExxonMobil Upstream Research, and reviewed through ExxonMobil Production Company and ExxonMobil Development Company. The well has been designed to explicitly sample the regional aquifer, by drilling down to 4800 m TVDss. By penetrating the top of Hibernia Layer 2 at 4500 m TVDss the probability of explicitly encountering the Hibernia South OWC will be maximized. Our interpretation based on Hibernia Layers 2/3 juxtaposition (leveraging the new APSDM) is that a continuous aquifer is shared by all Hibernia South blocks. In addition, we interpret a single continuous oil column across Hibernia South (except EE). We see this as a strategic investment to allow near-term decisions to be made timely and with a better information set. Furthermore we consider these costs as an overall investment toward an optimum development of Hibernia South. We agree that the volume of oil in the MM may be potentially small relative to other blocks but this too will be determined from this NFW well. Note, the MM NFW will have significant impact in determining probable reserves (~500 MBO STOOIP) for the Hibernia resource base, and the subsequent sidetrack to OPGG1 location will provide the basis for proved reserves (as per SEC guidelines). **Therefore, the strategic importance for defining the resource base and implications for development options cannot be understated.**[19]

[Emphasis added.]

[31] In response to Mr. Gremell's concern that there was no economic benefit to accelerating the delineation of the Hibernia southern extension by one year, Mark Evans states, in part:

> The MM NFW provides both near term economic incentives as well as strategic value. The strategic value of the MM NFW is key, including allowing us to optimize and accelerate Hibernia South development planning and the EL 1093 commitment. Our initial scoping showed subsea water injection to be potentially economic in the high side case. The de-risking of the OWC by year-end 2005 is

[18] Lines 18 to 28 of page 148 and lines 1 to 7 of page 149 of Volume 2 of the Transcript. The e-mail chain is at Tab 47 of the JBD.
[19] Page number 4 of Tab 47 of the JBD. Note that this is actually the first page at Tab 47.

> required to preserve this option. Economics for platform debottlenecking based on a risked success case show both an acceleration benefit by near term increases in oil rates of ~20,000 BOPD and capture reserves due to vaporization of additional oil through gas cycling. This analysis is being finalized as part of our Asset Business Planning process **but it is clear that understanding the full extent of the Hibernia South reserve potential allows for timely decisions to optimize development.**
>
> . . .
>
> Concerning other drill well options, we see drilling OPGG1 as the next well as a safe option from a perspective of contacting oil but it provides no significant additional information regarding the Hibernia South resource. The well would need to wait on its complimentary water injector, which because of its complexity (>9 mo. for long lead items, ~9 km MD and 4.7 km TVD, and $57 M Cdn) cannot be accelerated further in the schedule. Also the optimal location for the GG block water injector is contingent on OWC knowledge gained from the MM NFW. We have worked the drilling schedule recently to allow us to maintain production volumes essentially flat for the very near-term (excluding downtime) while aggressively advancing Hibernia South development.[20]

[Emphasis added.]

[32] A document titled "Authority for Expenditure" (AFE) dated June 27, 2005 endorsed and approved an expenditure of $43,090,000 to drill B16-54, which did not include the proposed sidetrack.[21] The following is stated under the heading AFE DESCRIPTION:

> The NFWMM1 well targets the Hibernia reservoir in EL1093. Once drilling and evaluation are complete, the MM wellbore will be abandoned and the well will be sidetracked.[22]

[33] EL1093 was an exploration licence granted by the Canada-Newfoundland Offshore Petroleum Board (the "CNOPB") effective January 15, 2005.[23] Doctor Eastwood testified that the licence was secured by the owners of Hibernia (referred to collectively in the licence as the "interest owner" and individually as the "interest holders") because under the best-case scenarios some of the oil in the Hibernia southern extension could otherwise be in land still owned by the Crown.[24] The decision to acquire EL1093 must have been made in 2004 before the 2005

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[20] Pages 5 and 6 of Tab 47 of the JBD.
[21] Page 1 of Tab 7 of the JBD.
[22] Tab 7 of the JBD.
[23] Tab 10 of the JBD.
[24] Lines 23 to 28 of page 154 and lines 1 to 9 of page 155 of Volume 2 of the Transcript.

RCA was commenced since the licence is dated January 15, 2005 and the acquisition of the licence required a bidding process.[25]

[34] Sections 4 and 5 of EL1093 state:

4. <u>LICENCE REQUIREMENTS</u>

It is a condition precedent to the commencement of Period II of the term that the Licence requirements as described in clause 3 of Schedule III be satisfied within the time specified therein. Failure to satisfy this condition precedent shall result in reversion to Crown reserve without further notice at the end of Period I of the term, of the Lands, other than those lands converted to a significant discovery licence or a production licence.

5. <u>DEPOSITS</u>

(1) The interest owner shall make such deposit or deposits as may be required hereunder, in a form satisfactory to the Board, and in the amount, if any, set forth in Schedule III.

(2) Where a deposit has been made by the interest holders and the Board has made a determination that the requirements and obligations for which the deposit has been made have been satisfied, the Board shall direct that the deposit be refunded.

[35] Schedule III of EL1093 states, in part:

1. <u>TERM</u>

The effective date to commence the term of this Licence is January 15, 2005. This Licence shall have a term of nine (9) years consisting of two periods referred to as Period I and Period II. Period I shall commence as of the effective date. Period II shall immediately follow Period I.

(a) Period I is a period of five (5) years commencing on the effective date of this Licence as specified below. This period may be extended by one year if a Drilling Deposit is posted before the end of the fifth year.

(b) Period II immediately follows Period I and consists of the balance of the term of this licence.

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[25] Lines 8 to 14 of page 156 of Volume 2 of the Transcript.

(c) In order to va1idate this Licence for Period II, the drilling of a well must be commenced within Period I and diligently pursued to termination in accordance with good oilfield practice. Failure to fulfill this drilling requirement will result in the termination of this licence at the end of Period I.

(d) The validation well must adequately test a valid geological target to be declared to the Board by the interest owner prior to the commencement of the well.

(e) Upon the expiration of Period II, this Licence shall terminate and all Lands shall revert to the Crown except those which have been converted to a Significant Discovery Licence or a Production Licence.

(f) If a well has been commenced before the expiration of this Licence, this Licence will continue in force while the drilling of that well is being pursued diligently and for so long thereafter as may be necessary to determine the existence of a significant discovery based on the results of that well.

. . .

3. <u>LICENCE REQUIREMENTS</u>

The interest owner shall, prior to the end of Period I of the term, have spudded and be diligently pursuing one or more wells on the Lands in accordance with good oil field practice.

[36] Section 4 of Schedule III required the interest holders to provide a security deposit of $2,031,375 prior to the issuance of EL1093. The interest holders were given a credit against the deposit of 25% of allowable expenditures. Section 6 of Schedule III provided that allowable expenditures for a year were the total expenditures for that year based on stipulated rates that included $600,000 per day for well-drilling costs.

[37] Doctor Eastwood testified that B16-54 was not drilled to satisfy the requirements of EL1093. He stated that B16-54 was expected to cost $43 million but the exposure under EL1093 was only the amount of the deposit.[26]

[38] The drilling of the B16-54 well started on August 1, 2005. The well was drilled to a vertical depth of 4,600 metres at which point the drill bit "torqued off"

[26] Lines 28 of page 158 and lines 1 to 9 of page 159 of Volume 2 of the Transcript.

the bottom of the well and was lost.[27] This precluded continuing to drill the well as originally planned. In February 2006, a supplemental AFE was requested to fund a sidetrack to the original target of B16-54.[28]

[39] A total of three attempts to sidetrack were made, but only the third attempt, which drilled straight down from the location of the sidetrack, achieved a modicum of success in that it obtained one pressure measurement and some core material.[29] This information was however sufficient to establish that oil was present at that depth and that the oil pressure in MM block was consistent with the oil pressure in blocks DD and Z.[30]

[40] Doctor Eastwood testified that the B16-54 well was drilled to test the oil-water contact predictions made by the new RCA and to validate the RCA model.[31] Doctor Vrolijk stated that B16-54 provided considerable experimental validation of the RCA methodology.[32]

III. Analysis

A. **The Resource Allowance Issue**

[41] In *Cameco Corporation v. The Queen*, 2018 TCC 195 ("Cameco"), I summarized the now repealed resource allowance regime as follows:

> [858] For taxation years ending before 2007, the ITA generally permitted taxpayers to claim a resource allowance in respect of income generated from certain natural resource production and processing activities. Specifically, former paragraph 20(1)(v.1) provided that, in computing a taxpayer's income for a taxation year from a business or property, there may be deducted such amount as is allowed by regulation in respect of, among other things, mineral resources in Canada. At the same time, paragraph 18(1)(m) denied the deduction of royalties, taxes and other amounts paid to a Canadian federal or provincial government, agent or entity in relation to the acquisition, development or ownership of a Canadian resource property, or the production in Canada of, among other things,

[27] Lines 15 to 28 of page 168 and lines 1 to 8 of page 169 of Volume 2 of the Transcript. The Schedule of Wells issued by the CNOPB states that the B16-54 well was spudded on August 1, 2005 and terminated on February 15, 2006 and that the true vertical depth of the well was 4,672.45 metres: page 1 of Tab 9 of the JBD.
[28] Lines 9 to 28 of page 169 and line 1 of page 170 of Volume 2 of the Transcript and page 5 of Tab 7 of the JBD.
[29] Lines 10 to 24 of page 173 of Volume 2 of the Transcript.
[30] Lines 2 to 6 of page 174 of Volume 2 of the Transcript.
[31] Lines 9 to 20 of page 56, lines 21 to 28 of page 57, lines 1 to 6 of page 58 and lines 19 to 23 of page 179 of Volume 2 of the Transcript.
[32] Lines 17 to 20 of page 121 of Volume 5 of the Transcript.

> metals, minerals or coal from a mineral resource located in Canada (to any stage that is not beyond the prime metal stage or its equivalent).
>
> [859] The regulations referred to in paragraph 20(1)(v.1) are found in Part XII of the ITR. The resource allowance is computed using a multi-step process as follows: first, compute "gross resource profits" under subsection 1204(1) of the ITR; second, compute "resource profits" under subsection 1204(1.1) of the ITR; third, compute "adjusted resource profits" under subsection 1210(2) of the ITR; and finally, compute the resource allowance by multiplying the taxpayer's adjusted resource profits by 25% under subsection 1210(1) of the ITR.
>
> [860] For years after 2002 and before 2007, paragraph 20(1)(v.1) allowed a deduction equal to a percentage of the resource allowance calculated under subsection 1210(1) of the ITR. The resource allowance deduction was eliminated for years after 2006.

[42] The Respondent takes the position that a portion of the Appellant's income from the sale of oil from the Hibernia field is not eligible for the resource allowance. The calculation by the Respondent of the portion in issue is based on the costs for the OLS.[33] I note that for the purpose of this analysis "OLS" refers not only to the loading system itself but to the pipes that connect the OLS to the GBS. The entire system is represented graphically in Figures 1 through 5 of the PSAF.

[43] Subsection 1204(1) of the ITR defines "gross resource profits". The components of that definition relevant to this analysis are found in subparagraphs 1204(1)(b)(i), (v) and (vi), which include in "gross resource profits":

> (b) the amount, if any, of the aggregate of his [the taxpayer's] incomes for the year from
>
> > (i) the production of petroleum, natural gas, related hydrocarbons or sulphur from
> >
> > > (A) oil or gas wells in Canada operated by the taxpayer, or
> > >
> > > (B) natural accumulations (other than mineral resources) of petroleum or natural gas in Canada operated by the taxpayer,
>
> . . .

[33] Paragraph 66 of the PSAF.

> (v) the processing in Canada of heavy crude oil recovered from an oil or gas well in Canada to any stage that is not beyond the crude oil stage or its equivalent, and
>
> (vi) Canadian field processing.[34]

[44] It has been long accepted that paragraph 1204(1)(b) of the ITR refers to sources of income that involve the activities described in subparagraphs 1204(1)(b)(i) through (vi). In *Echo Bay Mines Ltd. v. Canada*, [1992] 3 F.C. 707 (FCTD) ("*Echo Bay*"), the Court stated:

> If one turns to Regulation 1204(1), I note that a fuller excerpt of the words used in defining "resource profits" than that offered by the defendant more fully represents the provision. Thus, these profits are defined, in part in paragraph (*b*), as "the amount . . . of the aggregate of . . . incomes . . . from the production in Canada of . . . metals or minerals" [to the primary metal stage]. The use of the words "aggregate" and "incomes", and the implicit inclusion of "income . . . derived from transporting, transmitting or processing" [to the primary metal stage] in the case of metals or minerals under Regulation 1204(1)(*b*) which arises from Regulation 1204(3), both signify that income from "production" may be generated by various activities provided those are found to be included in production activities. Production activities yield no income without sales. **Activities reasonably interconnected with marketing the product, undertaken to assure its sale at a satisfactory price, to yield income, and hopefully a profit, are, in my view, activities that form an integral part of production which is to yield income, and resource profits, within Regulation 1204(1)**.[35]
>
> [Emphasis added.]

[45] The Respondent's position is summarized as follows:

> The core activity of production, being the extraction of petroleum from the ground, ceased at the wellhead. Other activities, to the extent that they are found to generate income from production, are source activities. Transporting the market ready crude oil from the Platform to the tankers is such an activity, and any

[34] "Canadian field processing" is defined in subsection 248(1) of the ITA. Paragraph (e) of the definition includes "the processing in Canada of crude oil (other than heavy crude oil recovered from an oil or gas well or a tar sands deposit) recovered from a natural accumulation of petroleum to any stage that is not beyond the crude oil stage or its equivalent".

[35] Page 732. The Federal Court of Appeal confirmed that this approach applied to the definition of "gross resource profits" in *The Queen v. 3850625 Canada Inc.*, 2011 FCA 117 ("*3850625 Canada*") at paragraph 21.

> income derived therefrom is properly removed from income from production by the exception in subparagraph 1204(3)(a).[36]

[46] Paragraph 1204(3)(a) of the ITR states:

> (3) A taxpayer's income or loss from a source described in paragraph (1)(b) does not include
>
> > (a) any income or loss derived from transporting, transmitting or processing (other than processing described in clause (1)(b)(ii)(C), (iii)(C) or (iv)(C) or subparagraph (1)(b)(v) or (vi)) petroleum, natural gas or related hydrocarbons or sulphur from a natural accumulation of petroleum or natural gas.

[47] For paragraph 1204(3)(a) of the ITR to apply, two circumstances must exist.

[48] First, the income or loss derived from transporting petroleum from a natural accumulation of petroleum must be included in the income of the taxpayer from the sources of income described in paragraph 1204(1)(b). Since paragraph 1204(1)(b) does not refer to transporting petroleum from a natural accumulation of petroleum, for income or a loss derived from that activity to be included in gross resource profits the transporting/transmitting of the petroleum must be integral to or sufficiently connected with the activities described in subparagraphs 1204(1)(b)(i), (v) and (vi).[37]

[49] Second, the taxpayer must have income or a loss that is derived from transporting/transmitting petroleum from a natural accumulation of petroleum. In my view, the word "derived"[38] means that the income or loss must exist not because the transporting/transmitting of the petroleum from a natural accumulation of petroleum was necessary in order to sell the petroleum but because the transporting/transmitting of the petroleum in and of itself generated income or a loss. In my view, this interpretation is consistent with the purpose of the resource allowance, which the federal government introduced in 1976 to provide a deduction in computing income in recognition of the fact that provinces impose taxes or royalties in respect of provincial resources.[39]

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[36] Respondent's Memorandum of Fact and Law Re: Hibernia Offshore Loading System Revenue Reclassified as Non-Resource Revenue, at paragraph 4.
[37] *3850625 Canada*, *supra*, footnote 35 at paragraph 21.
[38] The *Oxford English Dictionary* (2nd ed.) defines "derived" as follows: "Drawn, obtained, descended, or deduced from a source".
[39] Budget Speech dated June 23, 1975 at pages 33 and 34 and Budget Plan dated March 6, 1996 at page 162.

[50] The Appellants transported/transmitted crude approximately two kilometres from the GBS to the shuttle tankers, using the OLS. The crude was transported/transmitted to the shuttle tankers in this manner because, for safety and environmental reasons, the crude stored in the storage cells in the GBS could not be loaded directly from those storage cells onto the shuttle tankers. The crude changed ownership as it was loaded onto the shuttle tankers. It was then shipped either directly to a purchasing refinery or to Whiffen Head for subsequent shipment to a refinery.

[51] In the circumstances, I have no difficulty concluding that the transporting/transmitting of the crude from the GBS to the shuttle tankers was sufficiently connected with the marketing of the crude to be considered an integral part of the production of the crude for the purposes of paragraph 1204(1)(b) of the ITR. The question therefore is whether the Appellants derived any income from this activity that must be removed from their gross resource profits under paragraph 1204(3)(a).

[52] The evidence indicates that the only income realized by the joint venture owners from the production of crude was income from the sale of the crude to refineries. Paragraph 56 of the PSAF states that "[c]rude oil is priced on how much gasoline, jet, diesel and heating fuel can be made from it."

[53] Counsel for the Respondent submits that the use of the word "derived" in paragraph 1204(3)(a) means that the Appellants need not receive income from the transportation/transmission of the petroleum from the GBS to the shuttle tankers and that the use of the word "any" broadens the application of paragraph 1204(3)(a). The CRA addresses the absence of any actual income by calculating the Appellants' income derived from transporting/transmitting the crude from the GBS to the shuttle tankers by reference to the costs for the OLS.[40] Implicitly, the CRA is treating the amount so calculated as included in the Appellants' income from production under paragraph 1204(1)(b) and then is backing that income out of gross resource profits under paragraph 1204(3)(a).

[54] No doubt, the OLS allowed the joint venture owners of the crude to ship that crude to market so that income could be realized from the sale of the crude. However, the income realized by the joint venture owners from the sale of the crude was derived solely from the market value of the crude. The OLS had no impact one way or the other on the amount of income realized by the joint venture

[40] Paragraph 66 of the PSAF.

owners from the sale of the Hibernia crude and did not in and of itself generate any income or loss for the joint venture owners. Accordingly, there is no income derived from transporting/transmitting petroleum to which paragraph 1204(3)(a) may be applied. The use of the word “any” does not require the deduction of income derived from the transport/transmission of crude when no income from the transport/transmission of crude in fact exists.

[55] In summary, paragraph 1204(3)(a) was intended to ensure that additional income derived from transporting/transmitting crude does not attract the resource allowance. It was not intended to reduce a taxpayer’s income from the production of crude when that income reflects solely the market value of the crude.[41]

[56] For the foregoing reasons, the Appellants’ appeals in respect of the resource allowance issue are allowed.

B. **The Scientific Research and Experimental Development Issue**

[57] During 2005, well B16-54 was drilled to a depth of 4,600 metres, at which point the drill bit “torqued off” the bottom of the well and was lost. The principal issue is whether EMCHCL’s share of the cost of drilling the B16-54 well in 2005 qualifies as a scientific research and experimental development expenditure. The PSAF states that the cost of drilling well B16-54 in 2005 was $40,964,305 and that EMCHCL’s share of that cost was $2,048,215.[42]

[58] The phrase “scientific research and experimental development” (“SR&ED”) is defined in subsection 248(1) of the ITA as follows:

> “scientific research and experimental development” means systematic investigation or search that is carried out in a field of science or technology by means of experiment or analysis and that is
>
> > (a) basic research, namely, work undertaken for the advancement of scientific knowledge without a specific practical application in view,
> >
> > (b) applied research, namely, work undertaken for the advancement of scientific knowledge with a specific practical application in view, or

---

[41] The circumstances in this case may be distinguished from those in *Echo Bay* and *3850625 Canada*, where income was realized in addition to income from the sale of the natural resource.

[42] Paragraph 71 of the PSAF.

> (c) experimental development, namely, work undertaken for the purpose of achieving technological advancement for the purpose of creating new, or improving existing, materials, devices, products or processes, including incremental improvements thereto,

and, in applying this definition in respect of a taxpayer, includes

> (d) work undertaken by or on behalf of the taxpayer with respect to engineering, design, operations research, mathematical analysis, computer programming, data collection, testing or psychological research, where the work is commensurate with the needs, and directly in support, of work described in paragraph (a), (b), or (c) that is undertaken in Canada by or on behalf of the taxpayer,

but does not include work with respect to

> (e) market research or sales promotion,
>
> (f) quality control or routine testing of materials, devices, products or processes,
>
> (g) research in the social sciences or the humanities,
>
> (h) prospecting, exploring or drilling for, or producing, minerals, petroleum or natural gas,
>
> (i) the commercial production of a new or improved material, device or product or the commercial use of a new or improved process,
>
> (j) style changes, or
>
> (k) routine data collection.

[59] The Courts have identified five criteria that are useful in determining whether an activity constitutes SR&ED:

> 1) Was there a technological risk or uncertainty which could not be removed by routine engineering or standard procedures?
>
> 2) Did the person claiming to be doing SRED formulate hypotheses specifically aimed at reducing or eliminating that technological uncertainty?

> 3) Did the procedure adopted accord with the total discipline of the scientific method including the formulation testing and modification of hypotheses?
>
> 4) Did the process result in a technological advancement?
>
> 5) Was a detailed record of the hypotheses tested, and results kept as the work progressed?[43]

[60] The Appellant submits that the drilling of the B16-54 well was SR&ED because it provided experimental validation of the predictions made using the new/improved RCA methodology developed by Upstream Research Company.

[61] The Respondent submits that the drilling of well B16-54 was to delineate the oilfield in the Hibernia southern extension and to satisfy the requirements of EL1093 and that paragraph (h) of the definition of SR&ED excludes drilling for petroleum, which is consistent with the fact that the cost of oil wells is addressed in the definitions of “Canadian exploration expense” (“CEE”) and “Canadian development expense” (“CDE”) in subsections 66.1(6) and 66.2(5) respectively of the ITA.

[62] To support its position, the Appellant submitted the expert reports of Doctor Fairchild and to support her position the Respondent submitted the expert reports of Professor Gringarten.[44] While these reports provide some interesting technical background, they provide limited assistance with respect to the issue of whether the drilling of well B16-54 constitutes SR&ED. Moreover, to the extent that the expert reports attempt to address this issue directly, I am cognizant of the following caution by the Supreme Court of Canada in *R. v. Mohan*, [1994] 2 S.C.R. 9, given in the context of its discussion of whether expert evidence is necessary:

> There is also a concern inherent in the application of this criterion that experts not be permitted to usurp the functions of the trier of fact. Too liberal an approach could result in a trial’s becoming nothing more than a contest of experts with the trier of fact acting as referee in deciding which expert to accept.

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[43] *C.W. Agencies Inc. v. R.*, 2001 FCA 393, [2002] 1 C.T.C. 212, 2002 DTC 6740 (F.C.A.), paragraph 17. See, also, *Northwest Hydraulic Consultants Ltd. v. R.*, [1998] 3 C.T.C. 2520, 98 DTC 1839 (T.C.C.), paragraph 16; and *RIS-Christie Ltd. v. R.*, [1999] 1 C.T.C. 132, 99 DTC 5087 (F.C.A.), paragraph 10.

[44] Each expert prepared an expert report, a rebuttal report and a surrebuttal report.

> These concerns were the basis of the rule which excluded expert evidence in respect of the ultimate issue. Although the rule is no longer of general application, the concerns underlying it remain. In light of these concerns, the criteria of relevance and necessity are applied strictly, on occasion, to exclude expert evidence as to an ultimate issue.[45]

[63] This concern may be addressed at any time during the appeal. In *R. v. Sekhon*, 2014 SCC 15, [2014] 1 S.C.R. 272, Justice Moldaver stated at paragraph 46:

> Given the concerns about the impact expert evidence can have on a trial—including the possibility that experts may usurp the role of the trier of fact—trial judges must be vigilant in monitoring and enforcing the proper scope of expert evidence. While these concerns are perhaps more pronounced in jury trials, all trial judges—including those in judge-alone trials—have an ongoing duty to ensure that expert evidence remains within its proper scope. It is not enough to simply consider the *Mohan* criteria at the outset of the expert's testimony and make an initial ruling as to the admissibility of the evidence. The trial judge must do his or her best to ensure that, throughout the expert's testimony, the testimony remains within the proper boundaries of expert evidence. . . .

[64] Having said this, I find that two observations by Professor Gringarten provide useful background to the issue under appeal:

> . . . In any case, the validation of a reservoir model cannot rely on a single well but comes from the accumulation of proofs from a series of wells.[46]
>
> . . .
>
> All wells are drilled based on reservoir characterization and reservoir connectivity studies and in turn all wells, from wildcat to appraisal to delineation to development, contribute knowledge that is used to improve the reservoir model and reduce uncertainty.[47]

[65] The primary objectives, incentives and issues in respect of the B16-54 well are described in the presentation to management dated June 16, 2005 as follows:

> PRIMARY OBJECTIVES

[45] At page 24.
[46] Gringarten Report at pages 32 to 33.
[47] Gringarten Report at page 33.

- Define OWC in Hibernia South by penetrating primary reservoir targets of Layers 2 and 3 between 4500-4800 m (14764-15748 ft) TVDss - tests deepest possible contact.

- De-risk sufficient volumes to determine economic viability of platform facility upgrades and/or an 11 well subsea water injection development.

- Obtain core and fluid samples to characterize reservoir properties with depth to optimize future developments.

INCENTIVES

- The incremental risked STOOIP capture of NFW MM1 is 170 MB in up to 6 fault blocks.

- The risked unit development cost of the Hibernia South development is C$4-5/B.

- Fulfills EL 1093 commitment of C$8 M.

ISSUES

- Depth of OWC in Hibernia South is currently unknown but NFW MM1 will test interval of 4500-4800 m (14764-15748ft) TVDss. RCA and data from MM NFW derisks Hibernia South explicitly.

- Magnitude of potential reservoir quality (permeability and porosity) degradation with depth will be better understood through log and core acquisition.[48]

[66] The e-mail from Mark P. Evans found at Tab 47 of the JBD confirms the reasons for the drilling of the B16-54 well, which was to facilitate and accelerate the development of the Hibernia southern extension, in furtherance of which EL1093 had been obtained on January 15, 2005 (i.e., before the new/improved RCA methodology had been developed).

[67] The fact that the limited data provided by the B16-54 well, or more accurately sidetrack W, supported the prediction made using the new/improved RCA methodology is not proof that the well was a component of the SR&ED performed to create/improve that methodology. The fact that the path of well B16-54 was chosen to obtain the greatest amount of data at the least cost is also not proof that the well was a component of the SR&ED performed to create/improve

[48] Slide 2 of Tab 42 of the JBD.

the RCA methodology. Both facts are also consistent with the drilling of well B16-54 to facilitate and accelerate the development of the Hibernia southern extension, as stated in the documents at Tabs 42 and 47 of the JBD.

[68] The new/improved RCA methodology predicted the existence of significant amounts of oil in the Hibernia southern extension. Any well drilled in the southern extension subsequent to this prediction could potentially contribute data relevant to assessing the veracity of the prediction. However, common sense and commercial reality dictate that the primary purpose of any such well (even the first one) is not to validate the RCA methodology but rather to obtain data regarding oil in the southern extension. In this case, I find as a fact that well B16-54 was drilled to obtain data regarding oil in the southern extension and to satisfy the requirements of EL1093. The validation of the RCA methodology was incidental to these objectives. This conclusion is consistent with the fact that there was no evidence to tie well B16-54 to the formulation, testing and modification of the RCA methodology.[49]

[69] The drilling of a conventional well, based on the predicted location of oil, to establish whether and to what extent oil is present may be distinguished from the construction of a pilot plant to test a new or improved process or technology. The latter contributes to the resolution of technological uncertainty associated with the construction of a full scale plant while the former incidentally provides data that either agrees with or disagrees with the outcome predicted by the model.

[70] The conclusion that the drilling of well B16-54 was not SR&ED is reinforced and confirmed by paragraph (d) of the definition of SR&ED. That paragraph includes in the activities described in paragraphs (a) through (c) work undertaken with respect to data collection, provided that work is commensurate with the needs, and is directly in support, of those activities. However, paragraph (h) of the definition of SR&ED excludes any "work with respect to . . . prospecting, exploring or drilling for, or producing, minerals, petroleum or natural gas".

[71] The exclusion in paragraph (h) means that work with respect to data collection that is commensurate with and in support of basic research, applied research or experimental development does not include such work that constitutes prospecting, exploring or drilling for petroleum. In this case, well B16-54 was drilled to obtain data regarding the petroleum present in the Hibernia southern

[49] See, for example, the materials at Tab 5 of the JBD.

extension. Accordingly, the drilling of the well is excluded from the definition of SR&ED. This result is consistent with the fact that expenses for prospecting, exploring or drilling for petroleum are addressed in the definitions of CEE and CDE.

[72] On the basis of the foregoing, EMCHCL's appeal in respect of the SR&ED issue is dismissed.

IV. Conclusion

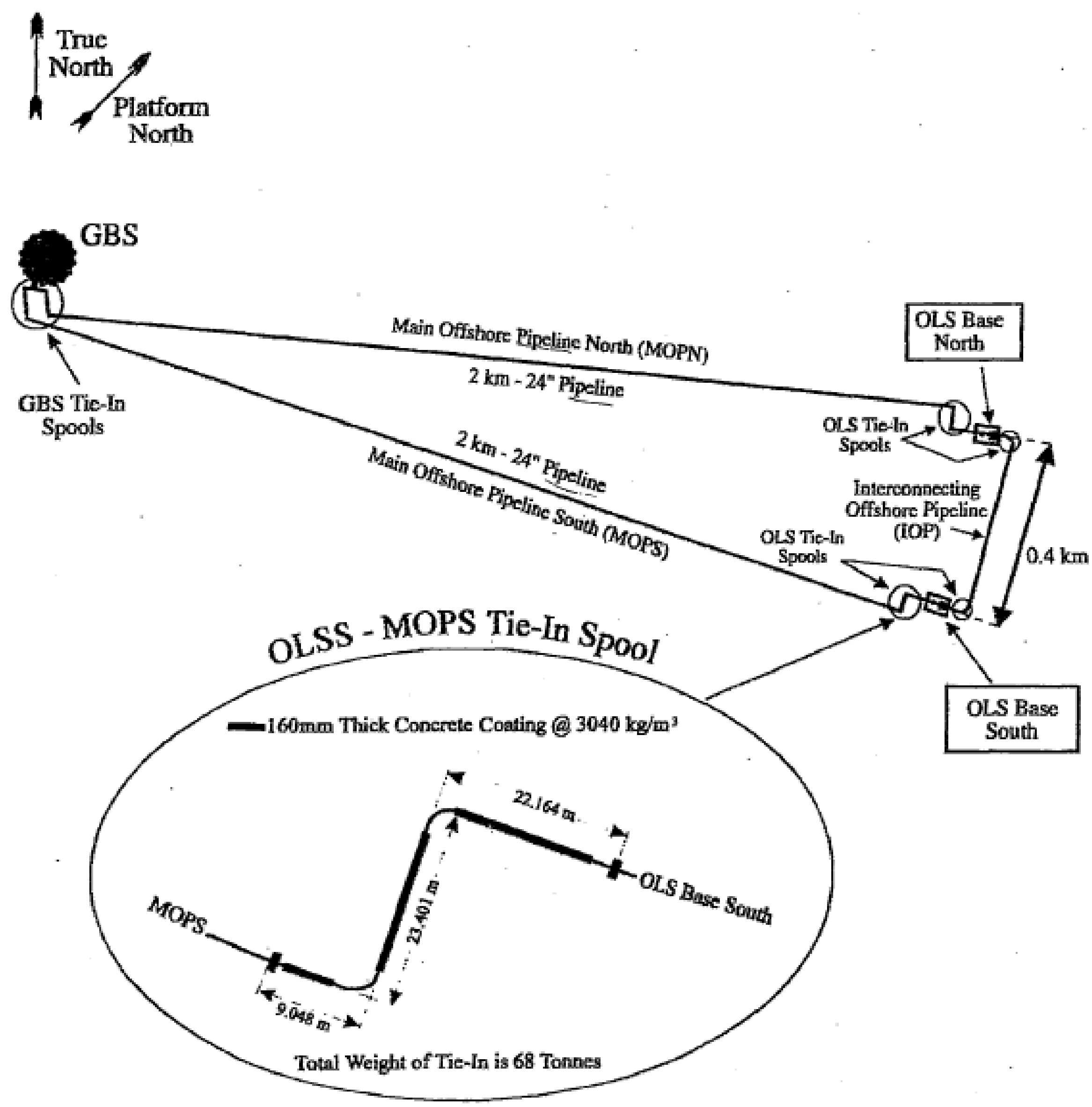
[73] The Appellants' appeals in respect of the resource allowance issue are allowed and EMCHCL's appeal in respect of the SR&ED issue is dismissed. In light of the split result, each party shall bear its own costs.

Signed at Ottawa, Canada, this 7th day of May 2019.

"J.R. Owen"

Owen J.

APPENDIX A



Note: Above figures are approximate.

Figure 1 - Hibernia Subsea Crude Loading Facilities Layout

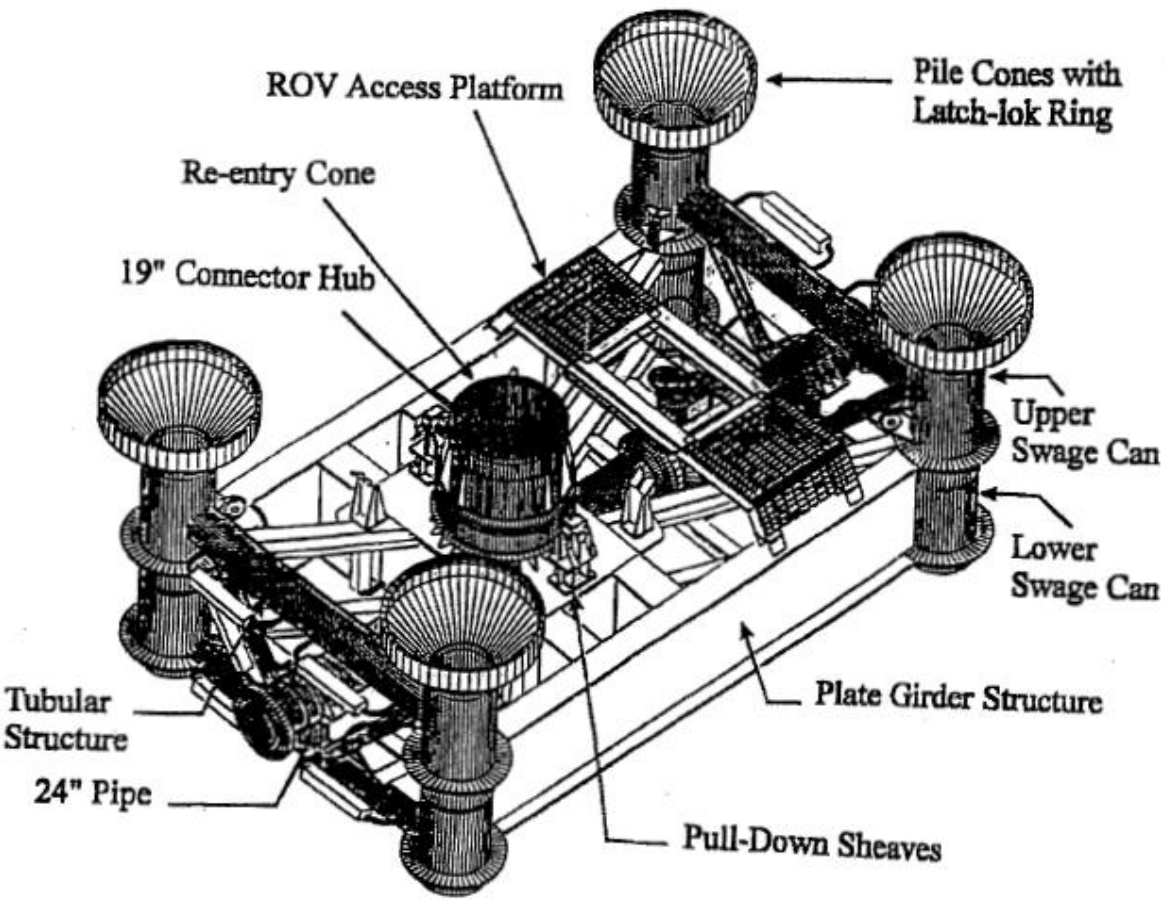


Figure 2 - Isometric of OLS Base

Page: 3

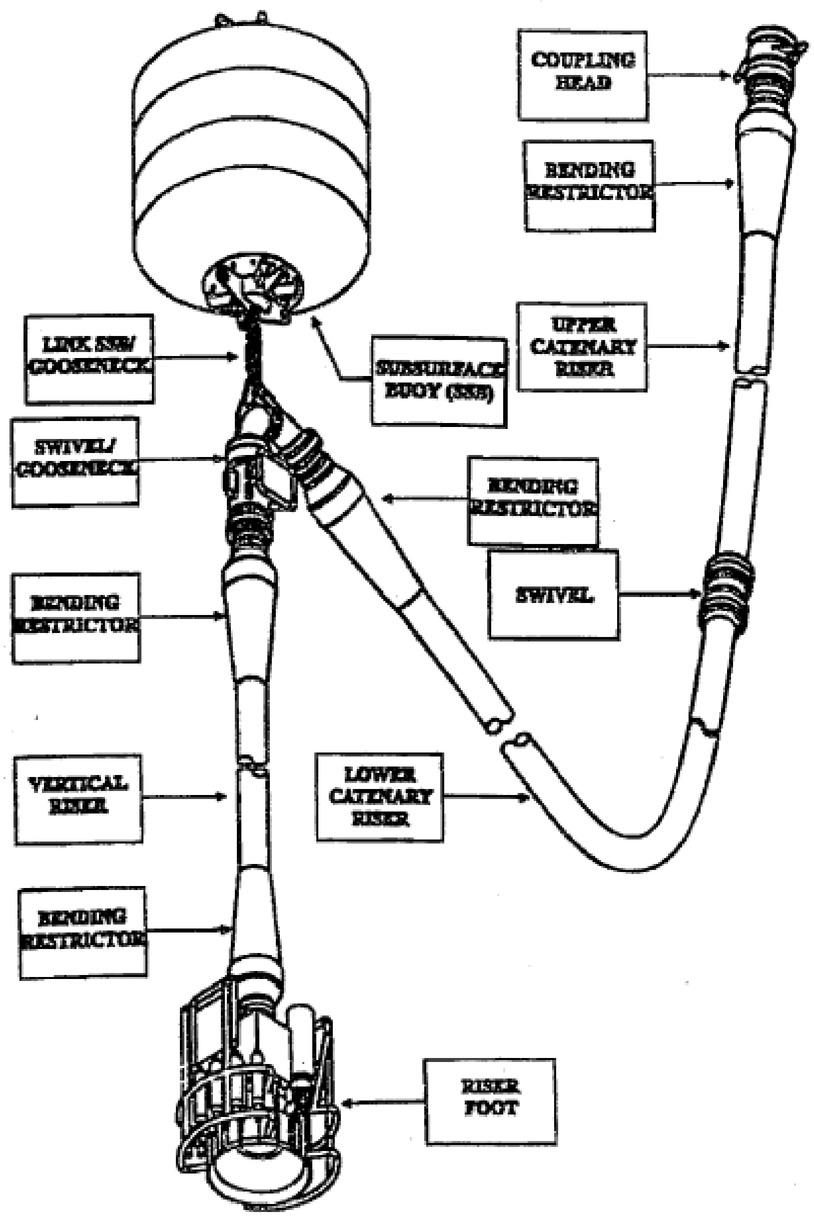


Figure 3 - Hibernia OLS Riser System

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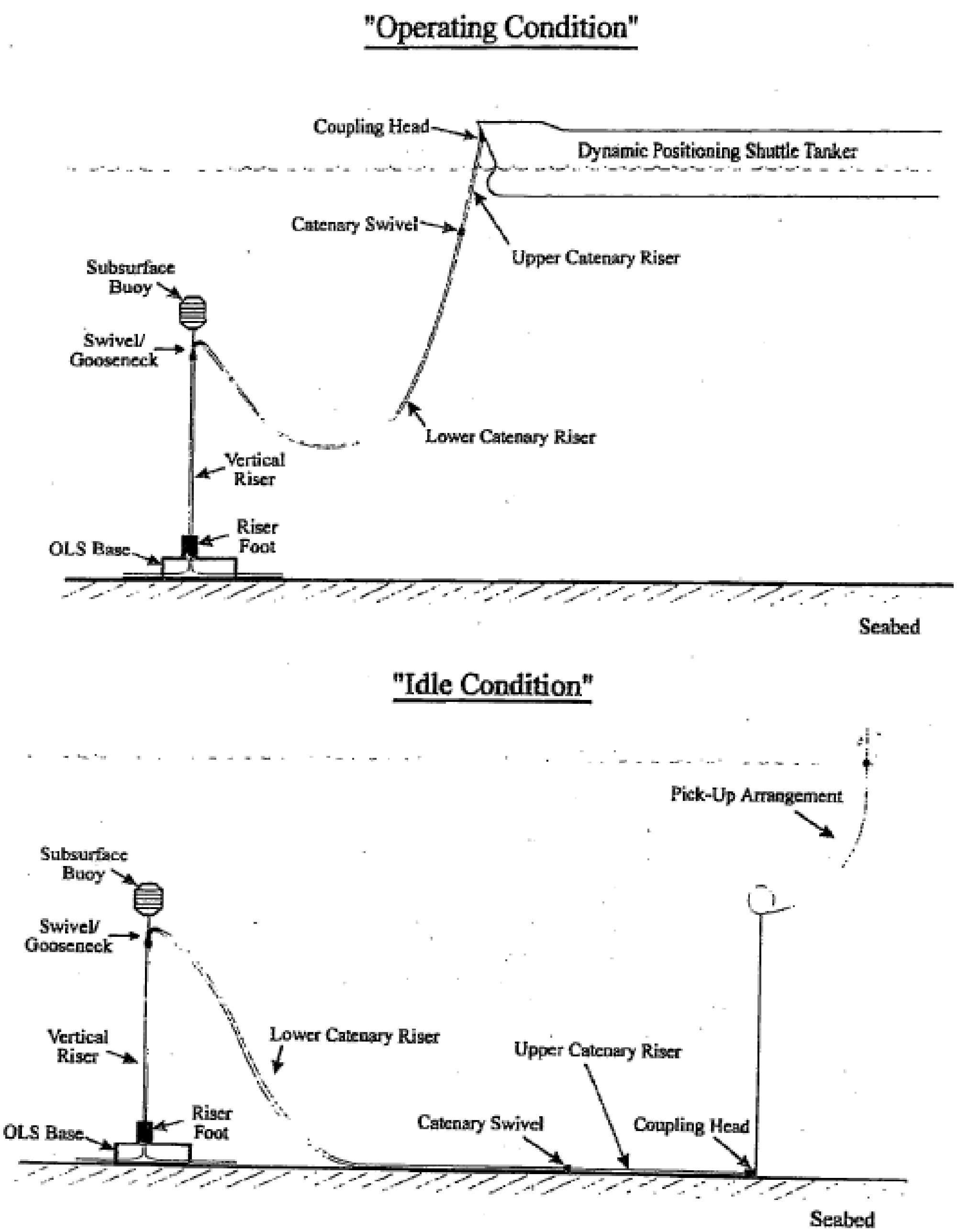

Figure 4 - OLS Riser in Operating and Idle Conditions

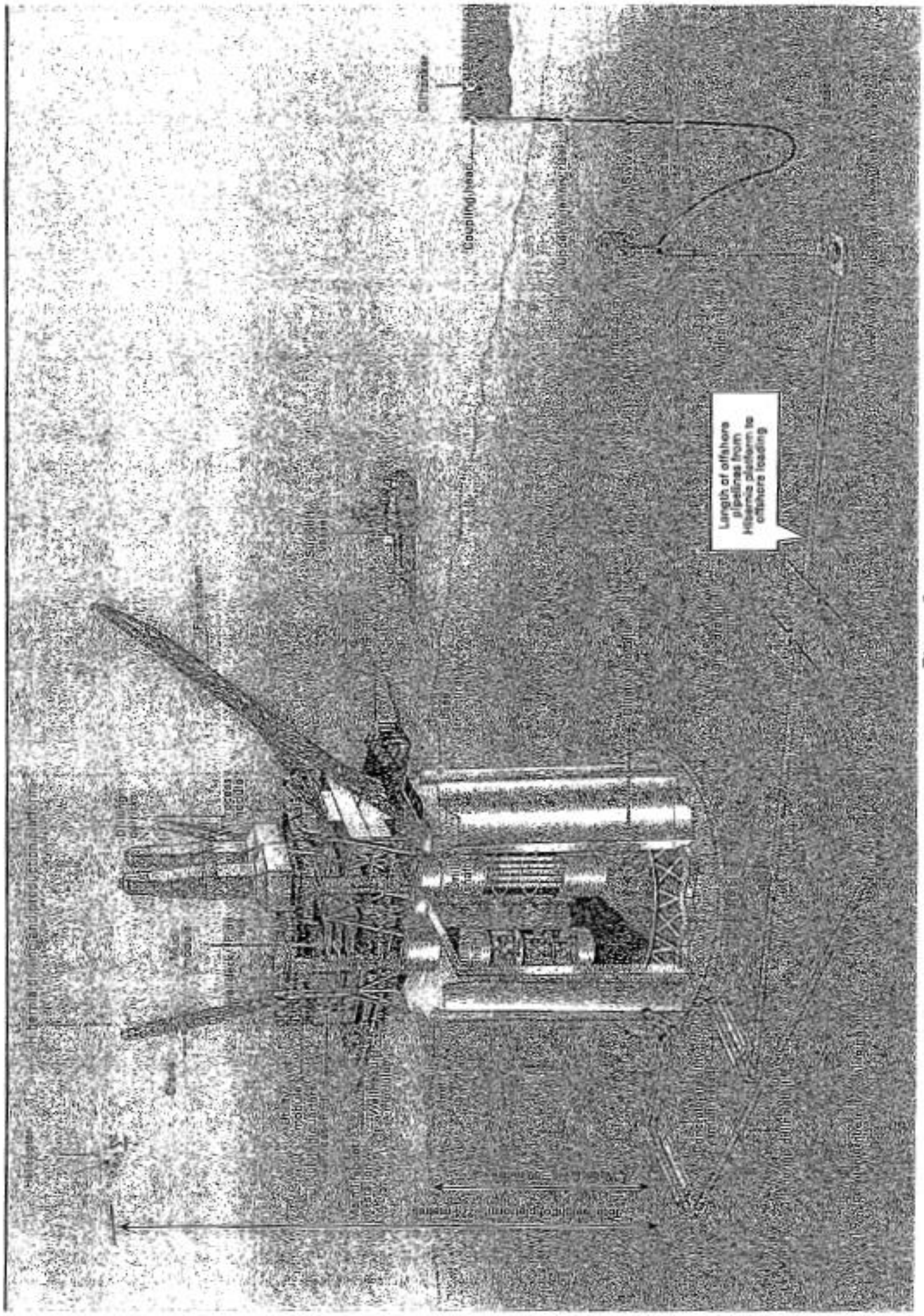
Coupling head
Length of offshore pipelines from Hibernia platform to offshore loading

Figure 5

CITATION:	2019 TCC 108
COURT FILE NOS.:	2003-705(IT)G and 2012-1389(IT)G
STYLES OF CAUSE:	EXXONMOBIL CANADA LTD. v. HER MAJESTY THE QUEEN EXXONMOBIL CANADA HIBERNIA COMPANY LTD. v. HER MAJESTY THE QUEEN
PLACE OF HEARING:	Calgary, Alberta
DATES OF HEARING:	January 14 to 17, 2019 January 21 to 24, 2019 January 28 and 29, 2019
REASONS FOR JUDGMENT BY:	The Honourable Justice John R. Owen
DATE OF JUDGMENT:	May 7, 2019
APPEARANCES:	
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Counsel for the Respondent:	Rosemary Fincham, Suzanie Chua and Cédric Renaud-Lafrance
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