Assessing the Economic Impacts of the Hebron Offshore Oil Project

A report prepared for the Commissioner of the Hebron Public Review Commission

Wade Locke, PhD

Wade Locke Economic Consulting

November 2, 2011

Table of Contents

List of Figures

List of Tables

Executive Summary

The Hebron Field is the next major oil producing project in the Newfoundland and Labrador offshore Jeanne d'Arc Basin region. The Hebron Development Application is currently under review by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB).

The C-NLOPB has appointed Commissioner Miller Ayre to conduct an independent Public Review of the Hebron Development Application.

This report to the Commissioner assesses the economic impacts of the Hebron Project and utilizes the information contained in the Hebron Development Plan as submitted by ExxonMobil, and C-NLOPB statistics for past production and forecasts for all producing oil fields in the Newfoundland and Labrador offshore.

Based upon the Hebron Development Plan project schedule and best-estimate for production, the project would account for 55% of oil production between 2016 – 2037, royalties and taxes would be $20 billion over the life of the project, during its peak years of production government revenues would be $850 million annually, and Research & Development / Education and Training contributions would be in excess of $200 million.

As outlined in the analysis contained in this report, the following observations are made:

- Offshore production from the existing projects, excluding Hebron, is expected to fall from 82 million barrels in 2016 to 33 million by 2021
- Hebron project, assuming first oil in late 2016, will account for more than 50% of the offshore production by 2019 and is expected to account for 55.6% of total production during the period of 2016-2037
- The internal rate of return for the Hebron project remains viable between 12% to 20% even with sensitivity analysis for variances in price of oil from $70 to $130 per barrel
- The provincial royalties and taxes based on the same sensitivity analysis for the price of oil will vary from $10.8 billion to $34.2 billion over the life of the project
- The Research and Development / Education and Training estimates, based on the same sensitivity analysis, range from $134 million to $288 million over the life of the project
- As the price of oil is in US dollars, the above calculations remain unchanged if the Canadian dollar remains at par; if the Canadian dollar ranges from $0.90 to $1.10, the net return will diminish if the Canadian dollar exceeds par. However, the project remains viable and contributes significantly to the provincial treasury
- Comparing Hebron to the Hibernia project for expenditures and employment:
    - Hibernia had a cumulative expenditure of 47% for local and 25% for other Canadian suppliers for a total of 72%
    - Hibernia had a cumulative employment of 66% for local and 12% for other Canadian residents for a total of 78%

  - Hebron, based on the Benefits Plan, has a planned expenditure of 44% for local and 23.5% for other Canadian for a total of 67.5%, plus/minus 25%
  - Hebron, based on the Benefits Plan, has a planned employment of 40% local and 20% other Canadian for a total of 60%, plus/minus 25%
- Comparing Hebron to the Hibernia project for construction cost per barrel of recoverable reserve estimate and adjusted for 2009 dollars:
  - The Hibernia pre-production capital cost is $13.43 per barrel (with a recoverable reserve base of 666 million barrels)
  - The Hebron pre-production capital cost, as outlined in the Development Plan, is $9.89 per barrel (with a recoverable reserve of 769 million barrels which includes Pools 1, 4, and 5 and Pool 3).
- The Hebron project, most importantly, will contribute between 60-70% of the offshore royalties to the province during its peak production period from 2021-2035. By comparison, within 10 years of commencing production, the average royalties received by the province from existing projects is expected to fall to $580 million per year but, with the impact of the Hebron project included, provincial royalties are expected to be nearly $1.6 billion per year.

1. Introduction

As per the requirements specified in the Atlantic Accord, the Hebron project is currently the subject of a public review being undertaken by the Hebron Public Review Commission. This public review is a normal part of the approval process specified in the Atlantic Accord for a project that comes under the purview of the Canada–Newfoundland and Labrador Offshore Petroleum Board's (C-NLOPB). As part of this public review of the Hebron project, this report to the Commissioner, utilizing the information described in the Hebron Development Plan and associated documents, assesses the financial viability of the Hebron project. In addition to this financial assessment, the economic implications to the various stakeholders are evaluated – this includes the equity holders as a group, NALCOR equity, the provincial treasury and the level of research and development required under the C-NLOPB 2004 guidelines. As well, sensitivity analyses assesses how sensitive the key economic parameters are to variations in output prices, exchanges rates, capital costs and production profiles (i.e., Hebron Main Field development with and without Pool 3). Finally, the Hebron project is compared to the Hibernia project in terms of (1) the costs per barrel at a comparable point in time when the decision to proceed was made, (2) the local expenditure benefits and (3) the employment impacts.

There are eight sections to this report:

- Section one is the introduction.
- Section two considers the contribution of Hebron to the continuity of oil production in the Newfoundland and Labrador offshore.
- Section three provides a detailed economic assessment of the Hebron project from the perspective of various stakeholders. This section also includes estimates of the Research and Development/Education and Training (R&D/E&T) expenditures implied by the price and output profiles utilized in this assessment.
- Section four analyzes the sensitivity of the economic impacts to variations in output prices, exchange rates and capital costs.
- Section five evaluates the local benefits associated with the Hebron project and compares them to those achieved by the Hibernia project.
- Section six compares the pre-production cost per barrel oil of Hebron and Hibernia.
- Section seven describes the relative contribution that the Hebron project makes to provincial royalties.
- Section eight contains the conclusion.

2. Contribution to Offshore Production

There are at least three production profiles for the Hebron project. One was released as part of the C-NLOPB's August 2011 annual forecast of offshore production[1] and the two other production profiles were released as part of the Hebron Development Plan – one for the main field development (i.e., Pools 1, 4, and 5) and the other for the development of Pool 3.[2] While the C-NLOPB forecast is based on annual production for the three existing projects and the Hebron project, and the production profiles in the Hebron Development Plan are based on daily production levels, there are other significant differences that merit further consideration.

Specifically, the C-NLOPB August 2011 annual forecast assumed production from Hebron would total 581 million barrels, while the Hebron Development Plan indicates that the production from the main field development (Pools 1, 4 and 5) is anticipated to reach total 645 million barrels. Production from the Pool 3 development is expected to equal 124 million barrels with a combined full field production estimated to be 769 million barrels. In other words, the expected production in the Hebron Development Plan exceeds the C-NLOPB estimate by 187 million barrels, which is 32% higher than the C-NLOPB August 2011 estimate. This is explained, in part, by the fact that the C-NLOPB estimate does not include production from the West Ben Nevis (Pool 2) or Ben Nevis (Pool 3) fields. Other differences in the production profiles are: (1) the C-NLOPB forecast assumes that production commences in 2017, instead of the 2016 start date indicated in the Hebron Development Plan and (2) the C-NLOPB estimate assumes that Hebron production reaches a plateau level of production and remains at the production plateau for six years before declining, while the Hebron Development Plan envisions oil production from the main field development ascending to a peak before declining. That is, there is no plateau. As well, Pool 3 production is modelled separately in the Hebron Development Plan and has not been integrated with the main field development. For the purpose of the analysis undertaken in this report, it is assumed that production from Pool 3 commences in 2020. While the actual start date will become known as information about the project evolves, 2020 was assumed for this analysis in order to ensure that the 150,000 barrel per day capacity of the GBS facility was not violated when Pool 3 production is added to the main field development.

The similarities and differences between each forecast are illustrated in Figures 1 and 2 below. While both profiles are reasonably similar, it is obvious that the production profiles in the Hebron Development Plan involve greater recoverable reserves and a longer period of production. Adding the production from Pool 3 further increases the cumulative level of production and the time horizon over which the Hebron field is expected to operate.

[1] In response to my request to Max Ruelokke for a copy of the production profile he utilized in an August 8, 2011 presentation to Minister Penashue, this forecast was provided in an email dated August 15, 2011 from Jeff O'Keefe of the C-NLOPB.

[2] The Development Plan also includes production profiles for high and low cases for both the main field development and for the Pool 3 development. They were not considered further in this report because no cost profiles were associated with them in the Hebron Development Plan.

Figure 1: A Comparison of the C-NLOPB 2011 Estimate for Hebron and the Main Field Estimate from the Hebron Development Plan

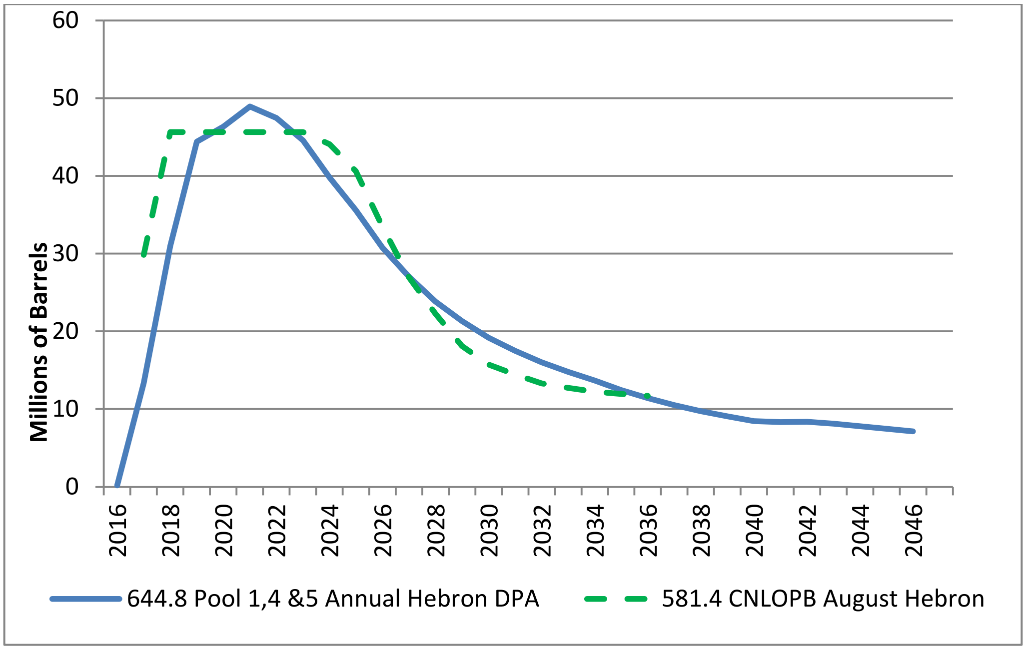
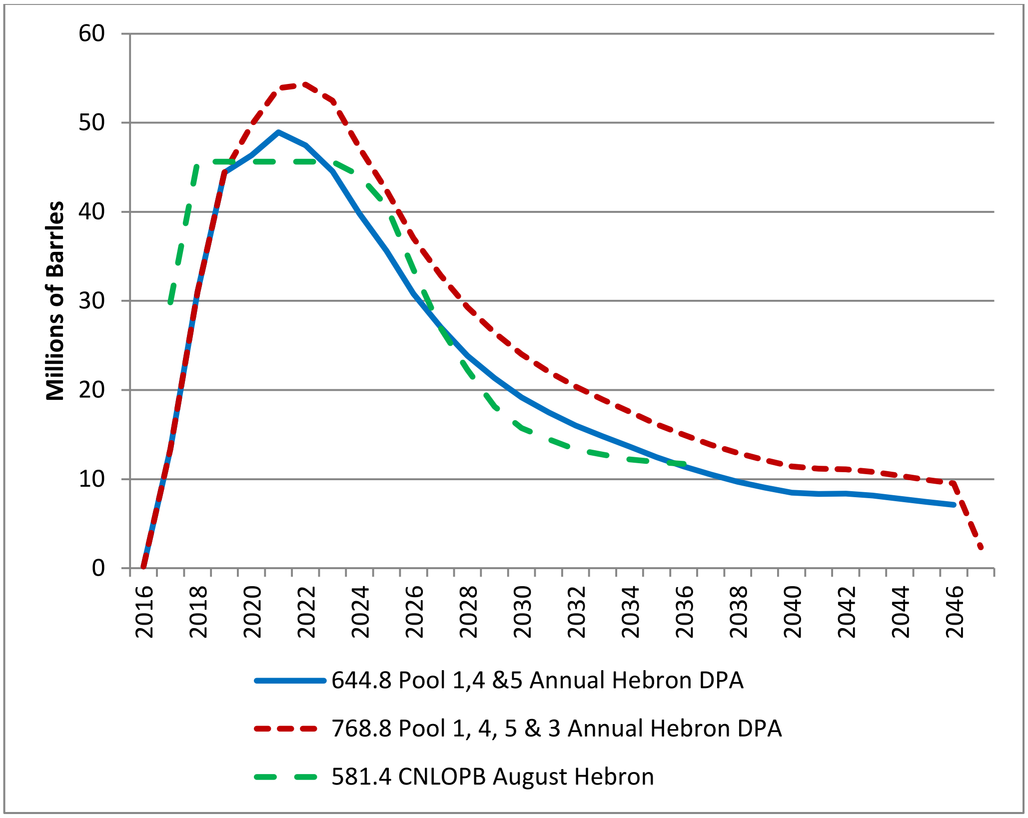


Figure 2: A Comparison of the C-NLOPB 2011 Estimate for Hebron, the Main Field Estimate from the Hebron Development Plan and the Main Field Including the Pool 3 Estimate from the Hebron Development Plan



2.1 C-NLOPB August Forecast of Production

Table 1 and Figure 3 show the production profiles available in the C-NLOPB August 2011 annual forecast. In interpreting the C-NLOPB August forecast, it is important to recognize that the C-NLOPB bases this forecast on the following assumptions:

1. The Hibernia total production profile is based on 1) the existing Hibernia field approved 1991, 2) the 2008 Development Plan Application (DPA) for AA Blocks and 3) the approval of the DPA for the Hibernia South Unit in 2010, with development beginning in 2011.
2. Terra Nova production profile is based on C-NLOPB forecast and reserve estimate (419 million barrels) in 2009.
3. Total White Rose Oil production numbers are based on the South Avalon Pool (207 million barrels), the North Avalon Pool (14.6 million barrels), the West White Rose Pool (40.4 million barrels) and the Hibernia formations (21 million barrels).
4. The White Rose forecast assumes development in the West Pool beginning in 2011, with additional wells online in 2013 and 2014. It also assumes development of the Hibernia formation in 2015 and development of the North Avalon Pool in 2023. However, the development of all these pools has yet to be approved by the C-NLOPB.

5. The forecast for the South White Rose Extension is based on the 2006 White Rose DPA concerning the South Extension and assumes development beginning in 2015.
6. The forecast for North Amethyst is based on the approved 2007 Development Plan.
7. The Hebron Field is assumed to commence production in 2017 for purposes of this forecast and does not include the West Ben Nevis (Pool 2) or Ben Nevis (Pool 3) fields.

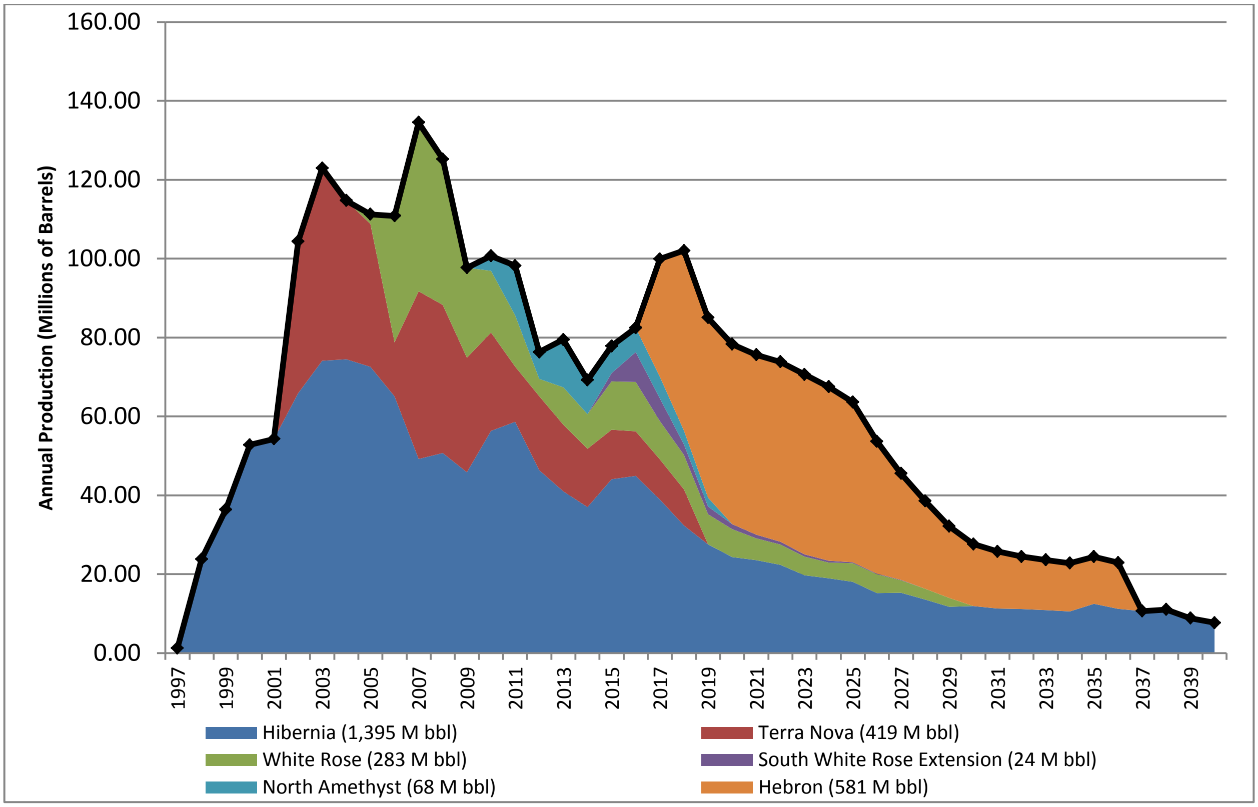
As Table 1 and Figure 3 illustrate, by the time that Hebron starts producing in 2017, the C-NLOPB August 2011 annual forecast indicates that production from the existing fields are in decline.

Table 1: Actual and Forecast Production Profiles for Newfoundland and Labrador Offshore Oil Projects – C-NLOPB's August 2011 Forecast (Millions of Barrels)

	Hibernia	Terra Nova	White Rose	South White Rose Extension	North Amethyst	Hebron	Total
1997	1.27						1.27
1998	23.80						23.80
1999	36.39						36.39
2000	52.79						52.79
2001	54.29						54.29
2002	65.87	38.47					104.33
2003	74.13	48.84					122.96
2004	74.50	40.22					114.72
2005	72.59	36.22	2.47				111.27
2006	65.10	13.69	32.05				110.84
2007	49.22	42.50	42.81				134.53
2008	50.73	37.55	36.96				125.24
2009	45.85	29.04	22.80				97.69
2010	56.34	24.93	15.67		3.75		100.69
2011	58.65	14.01	13.00		12.56		98.22
2012	46.37	18.76	4.40		6.80		76.33
2013	41.01	16.88	9.50		12.11		79.50
2014	37.02	14.77	8.78		8.65		69.23
2015	44.08	12.56	12.26	2.08	6.87		77.85
2016	44.93	11.30	12.51	7.58	6.13		82.45
2017	38.96	10.17	9.72	5.75	5.48	29.85	99.93
2018	32.36	9.15	8.74	2.65	3.50	45.63	102.03
2019	27.57		7.64	1.95	2.25	45.63	85.04
2020	24.35		7.09	1.26		45.63	78.32
2021	23.56		5.54	0.92		45.63	75.65
2022	22.38		5.16	0.69		45.63	73.85
2023	19.73		4.72	0.57		45.62	70.65
2024	18.97		4.00	0.46		44.08	67.51
2025	18.07		4.73	0.23		40.64	63.67
2026	15.21		4.78	0.16		33.52	53.67
2027	15.30		3.16	0.11		26.98	45.55
2028	13.58		2.74			22.27	38.59
2029	11.74		2.26			18.14	32.13
2030	11.93					15.73	27.65
2031	11.30					14.46	25.77
2032	11.18					13.32	24.49
2033	10.90					12.74	23.64
2034	10.57					12.23	22.80
2035	12.50					11.94	24.44
2036	11.22					11.71	22.93
2037	10.64						10.64
2038	11.04						11.04
2039	8.85						8.85
2040	7.69						7.69
Total	**1,395**	**419**	**283**	**24**	**68**	**581**	**2,771**

Source: C-NLOPB August 2011

Figure 3: Actual and Forecast Production Profiles for Newfoundland and Labrador Offshore Oil Project – C-NLOPB August 2011 Forecast (Millions of Barrels)



2.2 The Significance of Hebron for Offshore Oil Production in Newfoundland and Labrador

As Tables 2, 3 and 4 and Figures 4 and 5 demonstrate, Hebron, over its productive life and assuming no new projects come on stream during that time period, is expected to account for 55.6% of total offshore production during the period of 2016-2037. At its peak, in 2024, the Hebron project will produce more than 65% of annual offshore production in 2024. Hence, on a go-forward basis, the Hebron project is an extremely important project in ensuring continuity of production in Newfoundland and Labrador's offshore. As Figure 5 clearly illustrates, if Hebron does not come on stream in 2016 as anticipated, then offshore production will fall off dramatically. In particular, within five years of Hebron's assumed start, output from the existing fields would have fallen by more than half. That is, offshore production from the existing projects is expected to fall from 82 million barrels in 2016 to 33 million by 2021.

Over the expected productive life of Hibernia, Terra Nova, White Rose (including North Amethyst) and Hebron, the expected shares of output to come from each project are:

- Hibernia is expected to account for between 47.1% and 50.3% of total production;
- Terra Nova is expected to account for between 14.2% and 15.1% of total production;
- White Rose and North Amethyst are expected to account for between 12.7% and 13.6% of total production; and
- Hebron is expected to account for between 21.0% and 26.0% of total production.

Table 2: Expected Production as a Percent of Forecast Total Offshore Oil Production by Project – C-NLOPB August 2011 Forecast

Year	Hibernia as a Percent of Total Offshore Production	Terra Nova as a Percent of Total Offshore Production	White Rose & North Amethyst as a Percent of Total Offshore Production	Hebron as a Percent of Total Offshore Production
1997	100.0%			
1998	100.0%			
1999	100.0%			
2000	100.0%			
2001	100.0%			
2002	63.1%	36.9%		
2003	60.3%	39.7%		
2004	64.9%	35.1%		
2005	65.2%	32.5%	2.2%	
2006	58.7%	12.4%	28.9%	
2007	36.6%	31.6%	31.8%	
2008	40.5%	30.0%	29.5%	
2009	46.9%	29.7%	23.3%	
2010	56.0%	24.8%	19.3%	
2011	59.7%	14.3%	26.0%	
2012	60.7%	24.6%	14.7%	
2013	51.6%	21.2%	27.2%	
2014	53.5%	21.3%	25.2%	
2015	56.6%	16.1%	27.2%	
2016	54.5%	13.7%	31.8%	
2017	39.0%	10.2%	21.0%	29.9%
2018	31.7%	9.0%	14.6%	44.7%
2019	32.4%		13.9%	53.7%
2020	31.1%		10.7%	58.3%
2021	31.1%		8.5%	60.3%
2022	30.3%		7.9%	61.8%
2023	27.9%		7.5%	64.6%
2024	28.1%		6.6%	65.3%
2025	28.4%		7.8%	63.8%
2026	28.3%		9.2%	62.4%
2027	33.6%		7.2%	59.2%
2028	35.2%		7.1%	57.7%
2029	36.5%		7.0%	56.4%
2030	43.1%			56.9%
2031	43.9%			56.1%
2032	45.6%			54.4%
2033	46.1%			53.9%
2034	46.4%			53.6%
2035	51.2%			48.8%
2036	48.9%			51.1%
2037	100.0%			
2038	100.0%			
2039	100.0%			
2040	100.0%			
Share of Total	**50.3%**	**15.1%**	**13.6%**	**21.0%**

Table 3: Expected Production as a Percent of Forecast Total Offshore Oil Production by Project – C-NLOPB August 2011 Forecast and Hebron Main Field Estimate – Hebron Development Plan

Year	Hibernia as a Percent of Total Production	Terra Nova as a Percent of Total Production	White Rose & North Amethyst as a Percent of Total Production	Hebron as a Percent of Total Production
1997	100.0%			
1998	100.0%			
1999	100.0%			
2000	100.0%			
2001	100.0%			
2002	63.1%	36.9%		
2003	60.3%	39.7%		
2004	64.9%	35.1%		
2005	65.2%	32.5%	2.2%	
2006	58.7%	12.4%	28.9%	
2007	36.6%	31.6%	31.8%	
2008	40.5%	30.0%	29.5%	
2009	46.9%	29.7%	23.3%	
2010	56.0%	24.8%	19.3%	
2011	59.7%	14.3%	26.0%	
2012	60.7%	24.6%	14.7%	
2013	51.6%	21.2%	27.2%	
2014	53.5%	21.3%	25.2%	
2015	56.6%	16.1%	27.2%	
2016	54.4%	13.7%	31.7%	0.2%
2017	46.7%	12.2%	25.1%	16.0%
2018	37.0%	10.5%	17.0%	35.5%
2019	32.9%		14.1%	53.0%
2020	30.8%		10.6%	58.6%
2021	29.8%		8.2%	62.0%
2022	29.6%		7.7%	62.7%
2023	28.4%		7.6%	64.0%
2024	30.0%		7.0%	63.0%
2025	30.8%		8.5%	60.7%
2026	29.9%		9.7%	60.4%
2027	33.5%		7.2%	59.3%
2028	33.8%		6.8%	59.4%
2029	33.2%		6.4%	60.4%
2030	38.3%			61.7%
2031	39.3%			60.7%
2032	41.1%			58.9%
2033	42.4%			57.6%
2034	43.6%			56.4%
2035	50.1%			49.9%
2036	49.5%			50.5%
2037	50.3%			49.7%
2038	53.2%			46.8%
2039	49.4%			50.6%
2040	47.6%			52.4%
2041				100.0%
2042				100.0%
2043				100.0%
2044				100.0%
2045				100.0%
Share of	**49.2%**	**14.8%**	**13.3%**	**22.7%**

Table 4: Expected Production as a Percent of Forecast Total Offshore Oil Production by Project – C-NLOPB August 2011 Forecast and Hebron with Pool 3 Estimate – Hebron Development Plan

Year	Hibernia as a Percent of Total Production	Terra Nova as a Percent of Total Production	White Rose & North Amethyst as a Percent of Total Production	Hebron as a Percent of Total Production
1997	100.0%			
1998	100.0%			
1999	100.0%			
2000	100.0%			
2001	100.0%			
2002	63.1%	36.9%		
2003	60.3%	39.7%		
2004	64.9%	35.1%		
2005	65.2%	32.5%	2.2%	
2006	58.7%	12.4%	28.9%	
2007	36.6%	31.6%	31.8%	
2008	40.5%	30.0%	29.5%	
2009	46.9%	29.7%	23.3%	
2010	56.0%	24.8%	19.3%	
2011	59.7%	14.3%	26.0%	
2012	60.7%	24.6%	14.7%	
2013	51.6%	21.2%	27.2%	
2014	53.5%	21.3%	25.2%	
2015	56.6%	16.1%	27.2%	
2016	54.4%	13.7%	31.7%	0.2%
2017	46.7%	12.2%	25.1%	16.0%
2018	37.0%	10.5%	17.0%	35.5%
2019	32.9%	0.0%	14.1%	53.0%
2020	29.5%	0.0%	10.1%	60.3%
2021	28.1%	0.0%	7.7%	64.2%
2022	27.1%	0.0%	7.1%	65.8%
2023	25.5%	0.0%	6.8%	67.7%
2024	26.9%	0.0%	6.3%	66.8%
2025	27.6%	0.0%	7.6%	64.8%
2026	26.6%	0.0%	8.6%	64.8%
2027	29.7%	0.0%	6.4%	63.9%
2028	29.8%		6.0%	64.2%
2029	29.0%		5.6%	65.4%
2030	33.2%			66.8%
2031	33.9%			66.1%
2032	35.4%			64.6%
2033	36.6%			63.4%
2034	37.6%			62.4%
2035	43.6%			56.4%
2036	42.8%			57.2%
2037	43.4%			56.6%
2038	46.1%			53.9%
2039	42.2%			57.8%
2040	40.2%			59.8%
2041				100.0%
2042				100.0%
2043				100.0%
2044				100.0%
2045				100.0%
2046				100.0%
2047				100.0%
2048				100.0%
2049				100.0%
Share of Total	**47.1%**	**14.2%**	**12.7%**	**26.0%**

Figure 4: Expected Hebron Production as a Percent of Forecast Total Offshore Oil Production – A Comparison of C-NLOPB August 2011 Forecast, Hebron Development Plan Main Field Estimate and Hebron Development Plan with Pool 3 Estimate

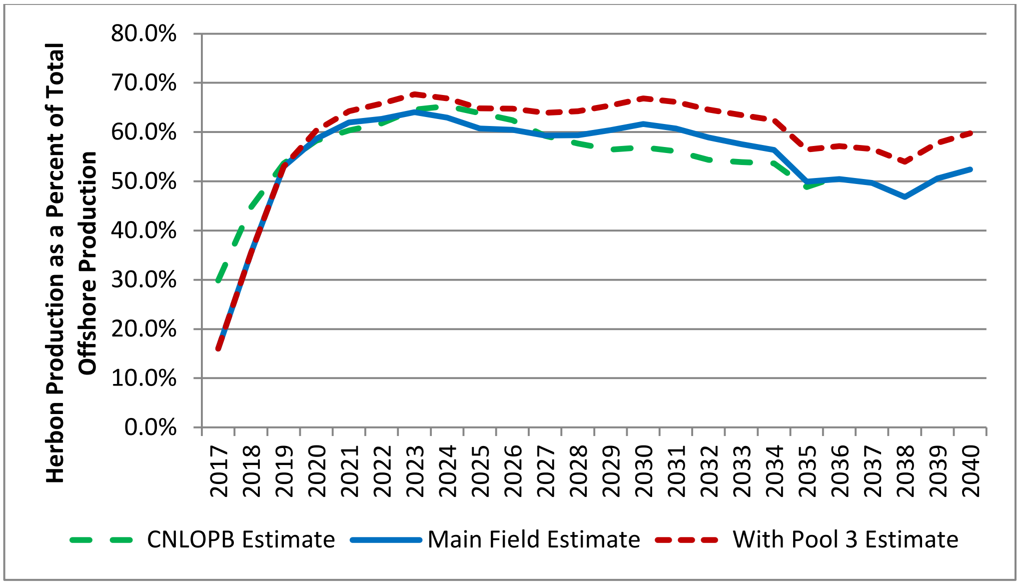
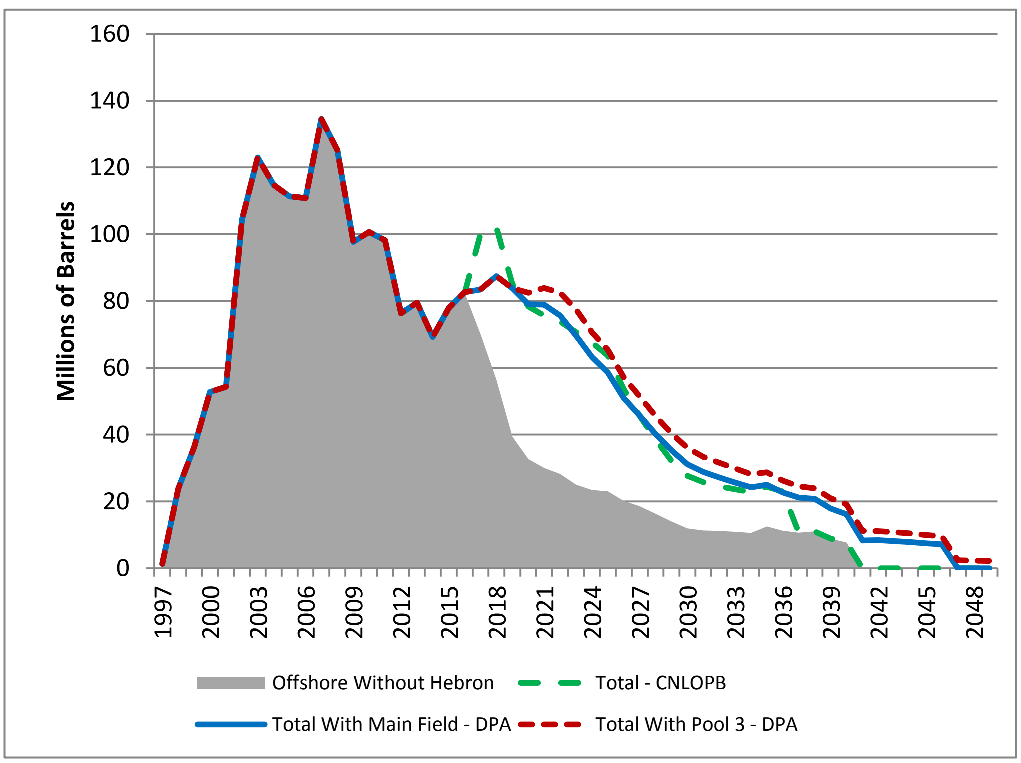


Figure 5: Offshore Production With and Without Hebron – C-NLOPB Estimate, Hebron Development Plan Main Field Estimate and With Pool 3 Estimate



3. Economic Analysis of the Hebron Project

The base case economic analysis undertaken for this report invokes the following assumptions:

1. The production profile for the main field development is equivalent to that provided in Table 6.6-3, p. 6.47 of the Hebron Development Plan;[3]
2. The production profile for Pool 3 development is equivalent to that provided in Table 6.6-5, p. 6-50 of the Hebron Development Plan;[4]
3. In order to ensure that the 150,000 barrel per day production capacity of the GBS facility (Hebron Development Plan p. 1-23) is not exceeded, Pool 3 production is assumed to commence in 2020;[5]
4. The historic expenditures for the Hebron project, as per the Hebron Development Application Summary p. 1-37, total $538.5 million as-spent dollars
5. Given that operating costs are expected to increase by 1 to 3% (Hebron Development Application Summary p. 1-41) when Pool 3 production occurs, the operating costs for the Hebron main field are increased by 2% in those years in which Pool 3 production occurs;
6. The capital and operating costs profiles for the main field development are taken from Table 1.16-2, p. 1-42 of the Hebron Development Application Summary;
7. The last year of operating costs includes an estimated $430 million (2009 dollars) in abandonment cost;
8. Since no transhipment and transportation costs are included in the costs estimates provided in the Hebron Development Plan, a combined cost of $2.00 Cdn (2011 dollars) per barrel are assumed;
9. The capital costs for the Pool 3 development are taken from Table 1.16-3 of the Hebron Development Application Summary;
10. As per the Hebron Development Application Summary (p. 1-42, p. 1-43), capital costs are assumed to be provided in mid-2009 prices. These are converted to mid-2011 costs estimates by adding 4% inflation to the estimates provided in the development plan;
11. Independent of the $120 million estimate provided in the Benefits Agreement with the Government of Newfoundland and Labrador and reiterated in the Hebron Socio-Economic Impact Statement and Sustainable Development Report p. 7-18, the Hebron's R&D/E&T requirements should be determined by the 2004 R&D Guidelines established by the C-NLOPB;
12. The offshore generic royalty will apply to the Hebron project with the following modifications: (1) a super royalty of 6.5% on top of the existing net royalties after both the net royalty payout is

[3] Table 6.6-11, p. 6-60 of the Hebron Development Plan provide best (645 million barrels), downside (503 million barrels) and upside (786 million barrels) estimates for the production profiles associated with the main field development. Only the best estimates were utilized in the economic analysis undertaken in this report because there were no corresponding cost estimates for the upside and downside production profiles.

[4] Table 6.6-14, p. 6-64 of the Hebron development Plan have best (124 million barrels), downside (75 million barrels) and upside (203 million barrels) estimates for Pool 3 production.

[5] While the proponent does indicate that, with de-bottlenecking the capacity of the GBS facility could reach 180,000 barrels per day, for the purposes of this analysis, it was decided to stick with more conservative 150,000 barrel per day capacity estimate. Also, on page 6-45 of the Hebron Development Application Summary, the proponent does indicate that "The optimal start-up timing for Pool 3 and the sizing/scope of the topside process equipment that may be required for Pool 3 development are also currently being studied."

achieved and the price of oil (WTI) exceeds $50 US/bbl; and (2) the basic royalty rate will remain at 1% until simple payout is achieved;

13. The assumed long-term bond rate for calculating net royalty payout is 4.5%;
14. The assumed rate of inflation is 2%;
15. The assumed exchange rate is $1.00 US/CDN;
16. The 2011 price of oil is $100 WTI and is assumed to grow with inflation; and
17. The WTI and Brent price gap is assumed to disappear before production commences from Hebron;[6]
18. The R&D benchmark is assumed to be 0.40% of the value of production; and
19. The long-term oil price is assumed to be the Brent crude price less 15%.

Based upon these assumptions, the economic impacts are presented in Table 5. At real prices of $100 per barrel, the main field development is expected to yield a 17% internal rate of return to the proponent. When the cost and the production profiles associated with Pool 3 are added, the internal rate of return for the combined project falls to 16%. The royalties expected to flow to the provincial treasury from the main field development are $13.5 billion, which when added to corporation income taxes and NALCOR equity total $16.6 billion. The corresponding impacts when Pool 3 is included are: $16.3 billion for royalties for a total of $20.0 billion in combined provincial revenue.

Finally, from the base-case parameters and in accordance with the C-NLOPB's guidelines, the R&D/E&T expenditure for the main field development would be $211 million, after adjusting for the development credit. The R&D/E&T expenditure when Pool 3 is added would be $244 million, after the development.

[6] The WTI/Brent oil price gap is assumed to disappear by the time Hebron production commences. Hence, in this analysis Brent and WTI prices can be used interchangeably.

Table 5: Oil Price Sensitivity for Main Field Development – Key Parameters

Parameter	Main Field	Main Field Plus Pool 3
Assumed Price	$100	$100
Quality Adjustment on WTI Price	85%	85%
Exchange Rate ($US/$CDN)	$1.00	$1.00
Inflation Rate	2%	2%
Nominal Pre-Production Capex ($M)	$7,016	$8,995
Pre-Production Capex ($M 2009)	$6,448	$8,178
Nominal Drilling Capex ($M)	$2,313	$4,559
Drilling Capex ($M 2009)	$1,887	$3,667
Historic Costs ($M)	$538	$538
Nominal Opex ($M)	$9,525	$10,811
Opex ($M 2009)	$5,833	
Production (M barrels)	644.8	768.8
Revenue ($M)	$75,704	$91,761
IRR (%)	17.0%	16.0%
Royalties ($M)	$10,312	$12,534
Super Royalties ($M)	$3,167	$3,785
Provincial CIT ($M)	$1,758	$2,072
Provincial Revenue ($M)	$15,237	$18,391
R&D Requirement ($M)	$211	$244
NALCOR Equity ($M)	$1,351	$1,612
NPV NALCOR @10% ($M)	$46	$47

4. Sensitivity Analyses

Three distinct sensitivity analyses were performed for this report. The first involved evaluating how sensitive key parameters were to variations in output prices. This was followed by a sensitivity analysis with respect to exchange rates. The final sensitivity analysis related to changes in the capital costs of developing the Hebron project.

4.1 Sensitivity Analysis – Output Prices

A series of oil price sensitivities were undertaken. Specifically, oil prices per barrel were allowed to vary from $70 to $130 in $10 per barrel increments to determine the implication of price variations on key economic parameters. The results of these analyses are presented in Tables 6 and 7 and Figure 6, 7, 8 and 9.

While the internal rates of return for the main field development range from 12.7% to 20.0% and from 11.6% to 19.2% for the main field and Pool 3 development combined, the project remains viable throughout this range. Moreover, given that prices are expected to exceed $80 per barrel in the longer term, the Hebron project should be economic to develop and produce for all reasonable price assumptions.

Obviously, the royalties flowing to the provincial treasury are directly correlated with the assumed oil price. For the range of sensitivities considered in this analysis, provincial royalties will range from $7.3 billion to $24.6 billion for the main field development and from $8.7 billion to $29.4 billion for the combined Pool 3 development.

Provincial Treasury revenues range from $9.2 billion to $28.6 billion for the main field development and from $10.8 billion to $34.2 billion for the full field development. Clearly, the Hebron project has a significant potential impact on the provincial treasury.

Finally, the R&D/E&T expenditure ranges from $134 million to $288 million for the main field development and from $151 million to $338 million for the full field development.

Table 6: Oil Price Sensitivity for Main Field Development – Key Parameters

Assumed Oil Price	$70	$80	$90	$100	$110	$120	$130
Quality Adjustment on WTI Price	85%	85%	85%	85%	85%	85%	85%
Exchange Rate ($US/$CDN)	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00
Inflation Rate	2%	2%	2%	2%	2%	2%	2%
Nominal Pre-Production Capex ($M)	$7,016	$7,016	$7,016	$7,016	$7,016	$7,016	$7,016
Pre-Production Capex ($M 2009)	$6,448	$6,448	$6,448	$6,448	$6,448	$6,448	$6,448
Nominal Drilling Capex ($M)	$2,313	$2,313	$2,313	$2,313	$2,313	$2,313	$2,313
Drilling Capex ($M 2009)	$1,887	$1,887	$1,887	$1,887	$1,887	$1,887	$1,887
Historic Costs ($M)	$538	$538	$538	$538	$538	$538	$538
Nominal Opex ($M)	$9,525	$9,525	$9,525	$9,525	$9,525	$9,525	$9,525
Opex ($M 2009)	$5,833	$5,833	$5,833	$5,833	$5,833	$5,833	$5,833
Production (M barrels)	644.8	644.8	644.8	644.8	644.8	644.8	644.8
Revenue ($M)	$52,992	$60,563	$68,133	$75,704	$83,274	$90,844	$98,415
IRR (%)	12.7%	14.2%	15.7%	17.0%	18.1%	19.1%	20.0%
Royalties ($M)	$5,728	$7,310	$8,804	$10,312	$14,320	$17,309	$19,952
Super Royalties ($M)	$1,591	$2,126	$2,653	$3,167	$3,667	$4,171	$4,680
Provincial CIT ($M)	$1,062	$1,291	$1,525	$1,758	$1,884	$2,054	$2,240
Provincial Revenue ($M)	$8,381	$10,727	$12,982	$15,237	$19,871	$23,535	$26,871
R&D Expenditure ($M)	$134	$159	$185	$211	$236	$262	$288
NALCOR Equity ($M)	$779	$967	$1,159	$1,351	$1,457	$1,598	$1,750
NPV NALCOR @10% ($M)	-$56	-$22	$12	$46	$73	$100	$127

Table 7: Oil Price Sensitivity for Main Field plus Pool 3 Development – Key Parameters

Assumed Oil Price	$70	$80	$90	$100	$110	$120	$130
Quality Adjustment on WTI Price	85%	85%	85%	85%	85%	85%	85%
Exchange Rate ($US/$CDN)	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00
Inflation Rate	2%	2%	2%	2%	2%	2%	2%
Nominal Pre-Production Capex ($M)	$8,995	$8,995	$8,995	$8,995	$8,995	$8,995	$8,995
Pre-Production Capex ($M 2009)	$8,178	$8,178	$8,178	$8,178	$8,178	$8,178	$8,178
Nominal Drilling Capex ($M)	$4,559	$4,559	$4,559	$4,559	$4,559	$4,559	$4,559
Drilling Capex ($M 2009)	$3,667	$3,667	$3,667	$3,667	$3,667	$3,667	$3,667
Historic Costs ($M)	$538	$538	$538	$538	$538	$538	$538
Opex ($M)	$10,811	$10,811	$10,811	$10,811	$10,811	$10,811	$10,811
Production (M barrels)	768.8	768.8	768.8	768.8	768.8	768.8	768.8
Revenue ($M)	$64,233	$73,409	$82,585	$91,761	$100,937	$110,113	$119,289
IRR (%)	11.6%	13.2%	14.7%	16.0%	17.3%	18.2%	19.2%
Royalties ($M)	$6,852	$8,834	$10,611	$12,534	$14,310	$20,292	$23,757
Super Royalties ($M)	$1,815	$2,496	$3,157	$3,785	$4,414	$5,040	$5,653
Provincial CIT ($M)	$1,238	$1,512	$1,795	$2,072	$2,356	$2,464	$2,678
Provincial Revenue ($M)	$9,905	$12,842	$15,564	$18,391	$21,080	$27,796	$32,089
R&D Requirement ($M)	$151	$182	$213	$244	$275	$307	$338
NALCOR Equity ($M)	$924	$1,149	$1,382	$1,612	$1,846	$1,933	$2,109
NPV NALCOR @10% ($M)	-$70	-$31	$9	$47	$86	$114	$145

Figure 6: The Sensitivity of the Internal Rate of Return to Variations in Oil Prices for Main Field Development and Including Pool 3 Development

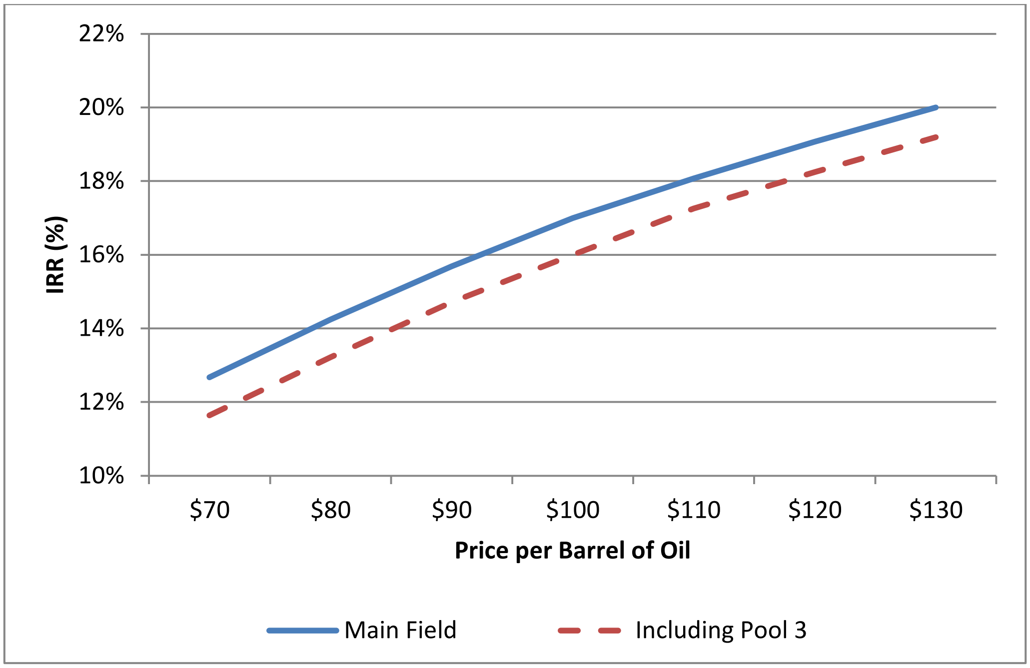


Figure 7: The Sensitivity of Provincial Royalties to Variations in Oil Prices for Main Field Development and Including Pool 3 Development

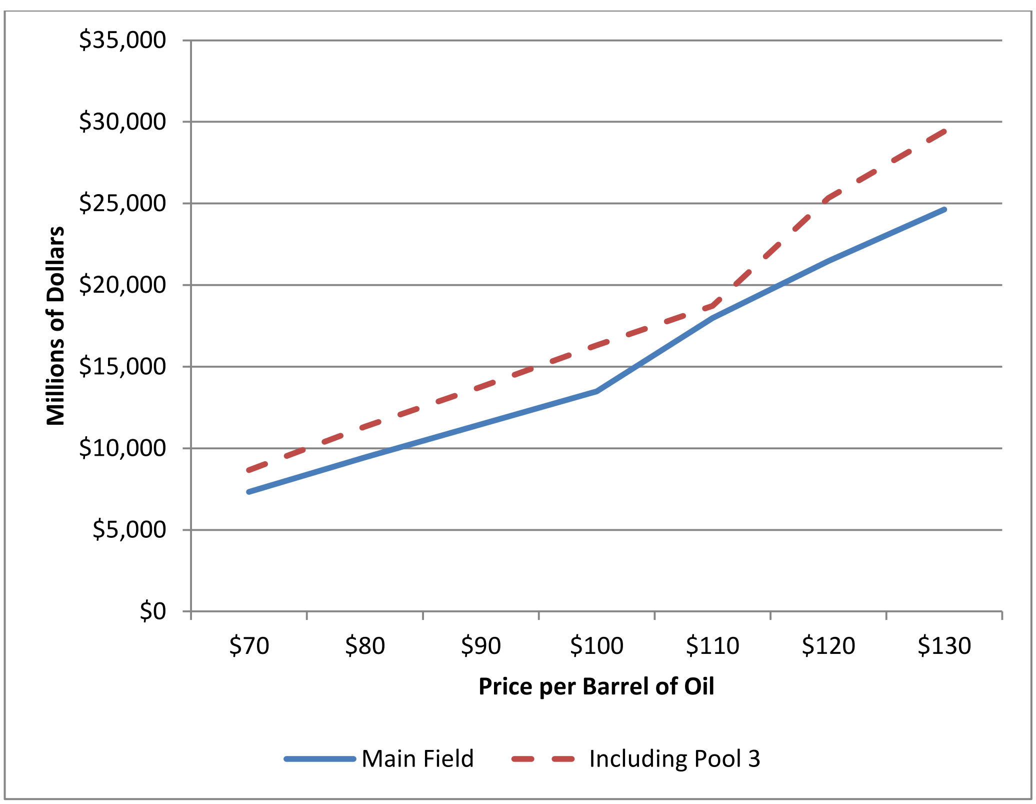


Figure 8: The Sensitivity of Provincial Revenues (including Equity) to Variations in Oil Prices for Main Field Development and Including Pool 3 Development

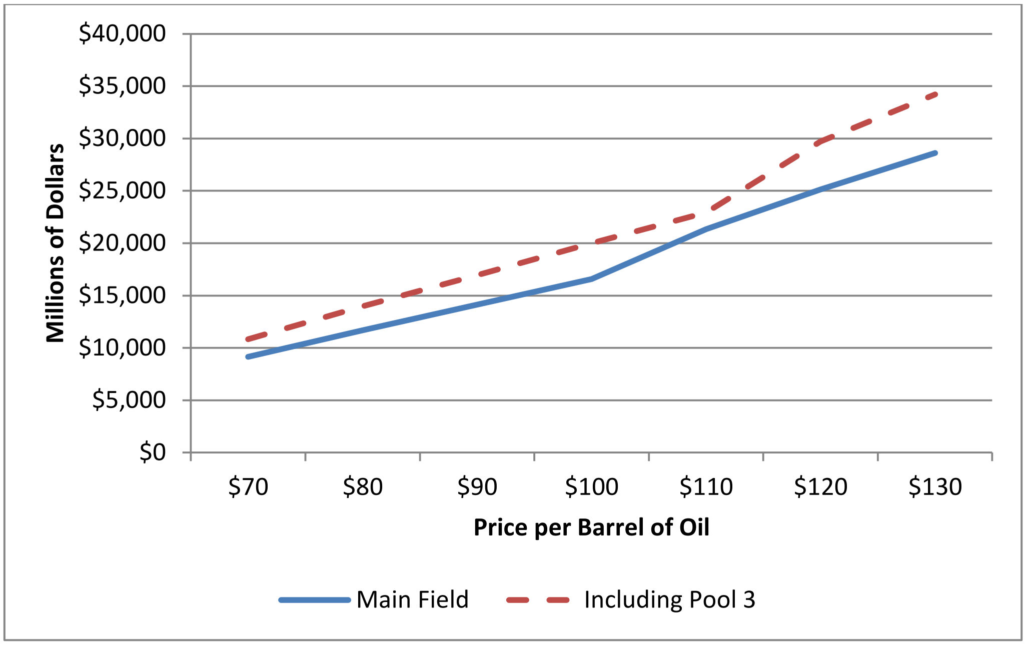
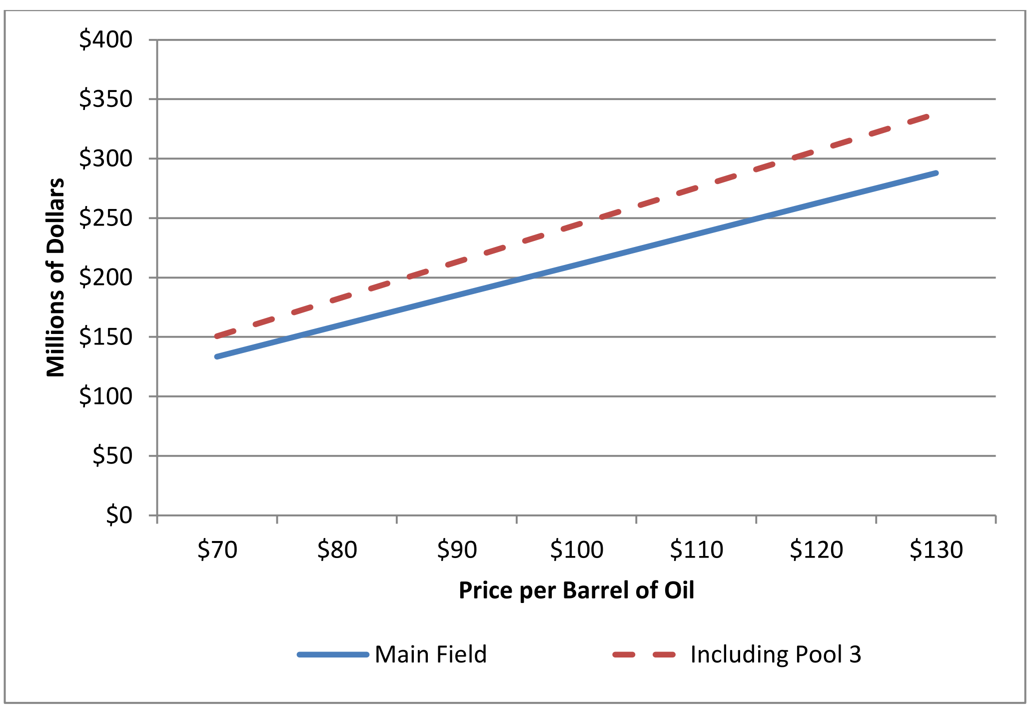


Figure 9: The Sensitivity of R&D/E&T Commitments to Variations in Oil Prices for Main Field Development and Including Pool 3 Development



4.2 Sensitivity Analysis – Exchange Rates

Tables 8 and 9 and Figures 10, 11 and 12 demonstrate the impacts of variations in the exchange rate on Hebron's internal rate of return, government royalties and R&D/E&T expenditures. For the purposes of illustration, the exchange is allowed to vary from $0.90 US/CDN to $1.10 US/CDN in increments of $0.05.

The higher the value of the Canadian dollar relative to its US counterpart, the lower is the internal rate of return because prices are denominated in US dollars per barrel and costs are specified in Canadian dollars. Consequently, the higher the value of the Canadian dollar, the lower is the Canadian-dollar-equivalent revenue earned for any oil price. It is as if the price of oil has fallen.

Over the range of exchange rate sensitivities, the internal rate of return on the project falls from 17.4% to 14.8% for the main field development and from 18.2% to 15.8% for the full field development. Even at the lowest value, the project remains viable. Similarly, provincial royalties are inversely tied to the exchange rates. The value of royalties estimated for the project falls from $18.4 billion to 11.6 billion for the main field development and from $9 billion to $14 billion for the full field development. Lastly, the R&D/E&T expenditures are reduced from $239 million to $187 million for the main field development and these expenditures are reduced from $279 million to $216 million when Pool 3 is added to the main field development.

Table 8: Exchange Rate Sensitivity for Main Field Development – Key Parameters

Assumed Exchange Rate	$0.90	$0.95	$1.00	$1.05	$1.10
IRR (%)	18.2%	17.6%	17.0%	16.4%	15.8%
Royalties ($M)	$14,695	$12,228	$10,312	$9,582	$8,938
Super Royalties ($M)	$3,723	$3,434	$3,167	$2,923	$2,700
R&D Expenditures ($M)	$239	$224	$211	$198	$187

Table 9: Exchange Rate Sensitivity for Main Field plus Pool 3 Development – Key Parameters

Assumed Exchange Rate	$0.90	$0.95	$1.00	$1.05	$1.10
IRR (%)	17.4%	16.7%	16.0%	15.4%	14.8%
Royalties ($M)	$14,514	$13,471	$12,534	$11,680	$10,771
Super Royalties ($M)	$4,484	$4,118	$3,785	$3,479	$3,215
R&D Expenditures ($M)	$279	$261	$244	$229	$216

Figure 10: The Sensitivity of the Internal Rate of Return to Variations in Exchange Rates for Main Field Development and Including Pool 3 Development

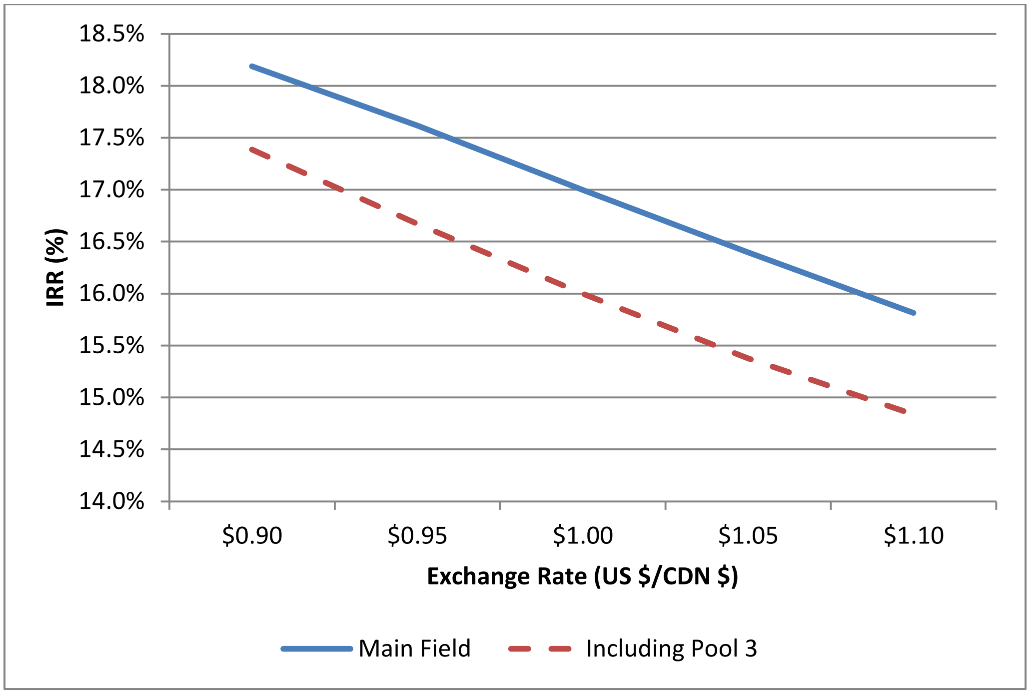


Figure 11: The Sensitivity of the Provincial Royalties to Variations in Exchange Rates for Main Field Development and Including Pool 3 Development

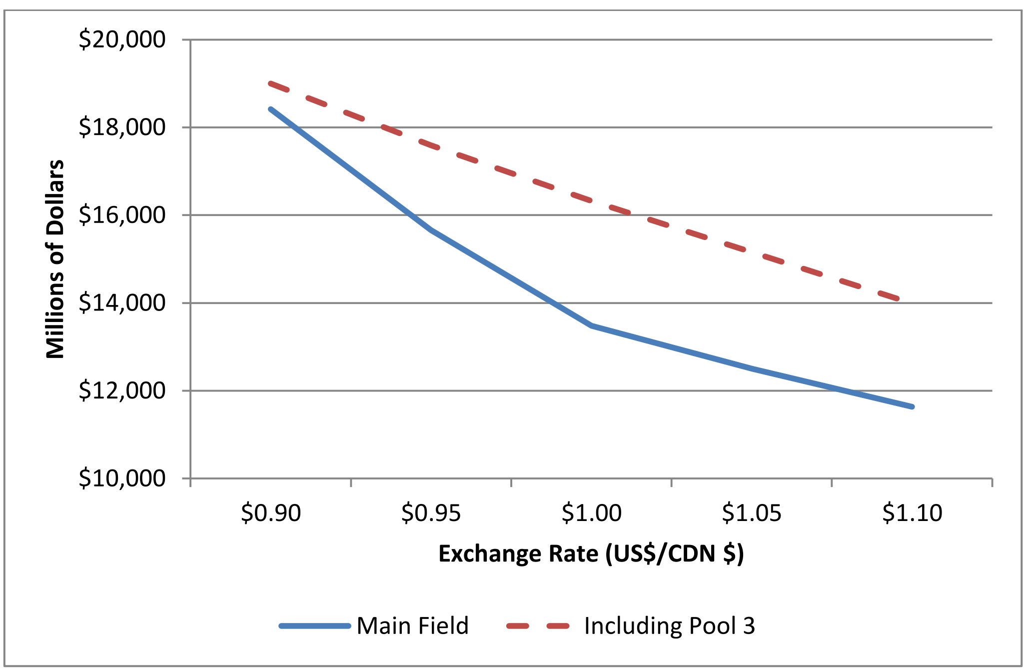
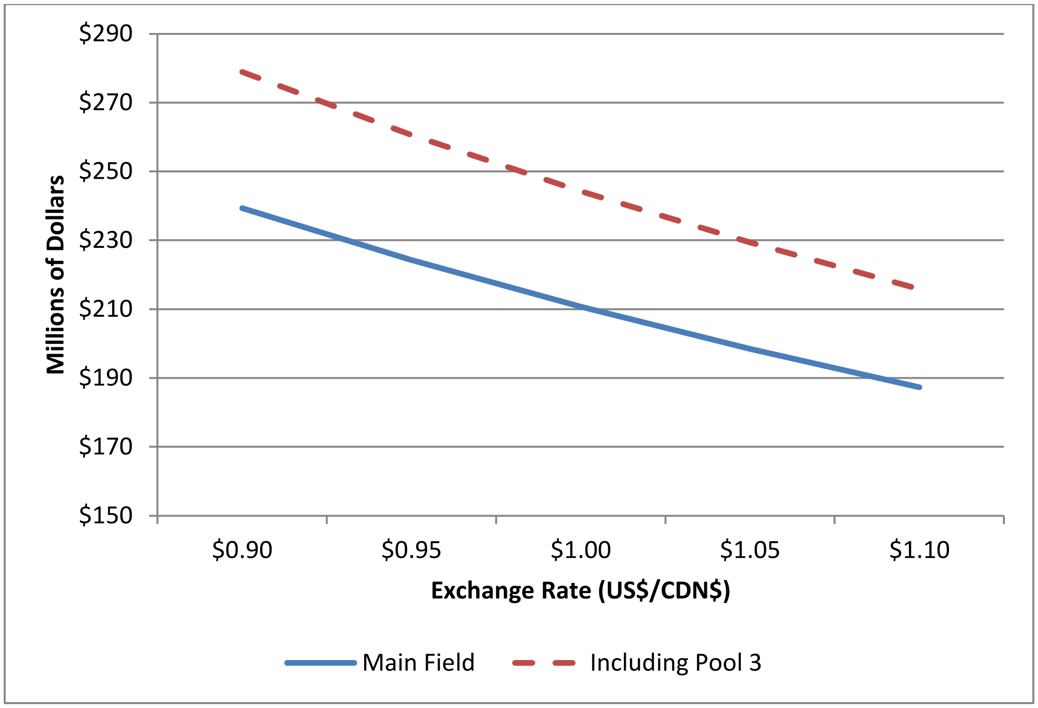


Figure 12: The Sensitivity of R&D/E&T Expenditures to Variations in Exchange Rates for Main Field Development and Including Pool 3 Development



4.3 Sensitivity Analysis – Cost Variations

In order to appreciate the implication of cost variation on key parameters, a sensitivity analysis was undertaken in which capital costs were varied from their base case values. Although drilling and facilities costs were allowed to vary, no changes were assumed to historic costs. The impacts associated with this sensitivity analysis are reported in Tables 10 and 11 and Figures 13, 14 and 15. A 10% increase in costs will lower the rate of return on the main field and full development by one percentage point. For example, the internal rate of return on the main field development falls from 17% to 16% and the internal rate of return on the full field development is reduced from 16% to 15%.

On the other hand, a 10% increase in capital costs will reduce provincial royalties by nearly $650 million for the full field development. This implies that local benefits obtained through an increase in capital cost will have a significant impact on provincial royalties.

The impact on R&D/E&T expenditures is small because these impacts are felt only through their effect on the development credit. For instance, an increase in cost of $100 million will only reduce the development credit for R&D/E&T by $5 million.

Table 10: Exchange Rate Sensitivity for Main Field Development – Key Parameters

Assumed Variation in CAPEX	85%	90%	95%	100%	105%	110%	115%
IRR (%)	18.6%	18.0%	17.5%	17.0%	16.5%	16.0%	15.5%
Royalties ($M)	$16,710	$15,846	$13,682	$13,479	$13,273	$13,078	$12,895
R&D Expenditure($M)	$218	$215	$213	$211	$208	$206	$204

Table 11: Exchange Rate Sensitivity for Main Field plus Pool 3 Development – Key Parameters

Assumed Variation in CAPEX	85%	90%	95%	100%	105%	110%	115%
IRR (%)	17.8%	17.2%	16.6%	16.0%	15.5%	15.0%	14.5%
Royalties ($M)	$19,272	$16,797	$16,563	$16,320	$16,067	$15,677	$15,431
R&D Expenditure ($M)	$218	$215	$213	$211	$208	$206	$204

Figure 13: The Sensitivity of the Internal Rate of Return to Variations in Costs for Main Field Development and Including Pool 3 Development

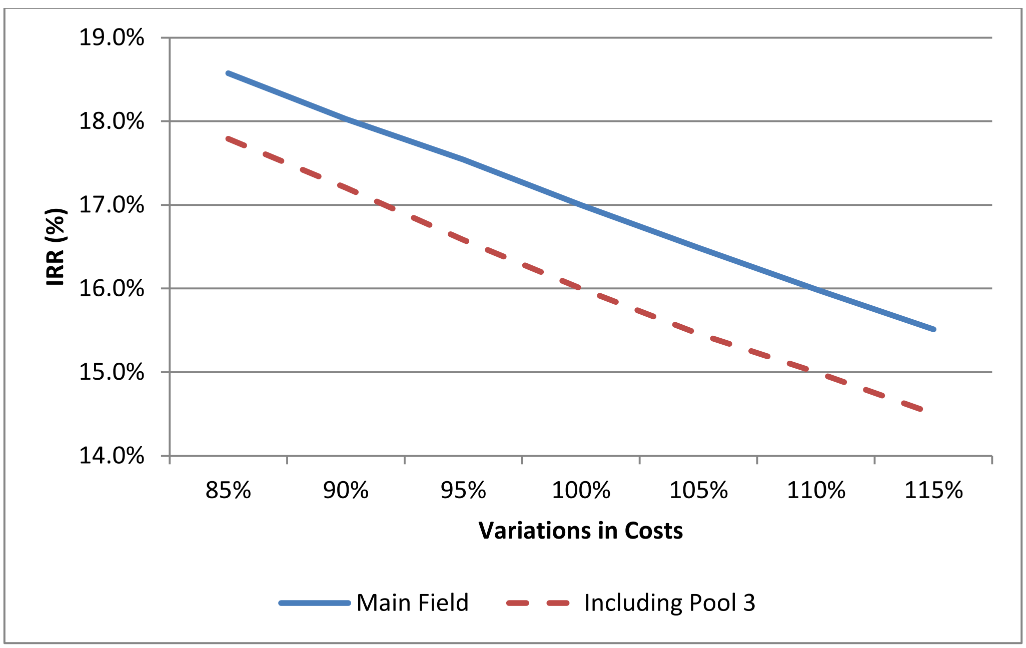


Figure 14: The Sensitivity of the Provincial Royalties to Variations in Costs for Main Field Development and Including Pool 3 Development

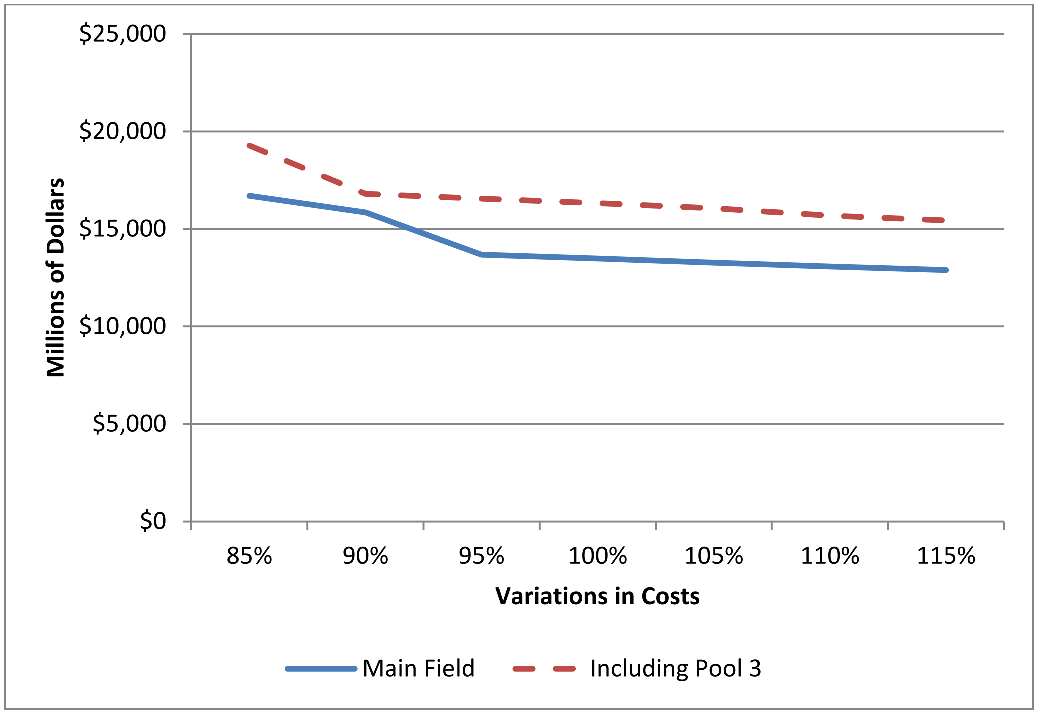
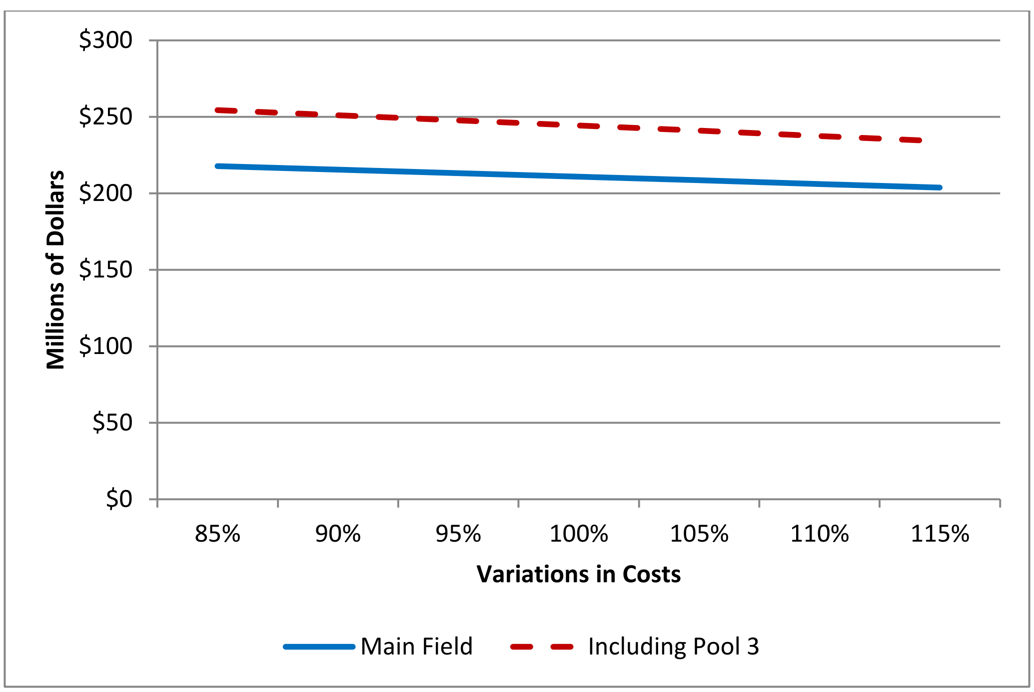


Figure 15: The Sensitivity of the R&D/E&D Expenditures to Variations in Costs for Main Field Development and Including Pool 3 Development



5. Local Benefit Comparison – Hebron to Hibernia

Although no specific analysis is provided,[7] the Hebron Benefits Plan (p. 4-27) suggests that “A preliminary calculation of the expenditure and employment content for the construction phase of Hebron has been prepared based on the latest budgetary estimates as of the time of writing, which are expected to be accurate to plus/minus 25 percent. Of the total Project cost, it is estimated that 35 to 55 percent will occur in Newfoundland and Labrador, 15 to 30 percent will occur elsewhere in Canada, and 25 to 40 percent will occur outside of Canada.” While it is not clear whether this relates to total project costs or all capital costs or all capital costs to first oil, for the purpose of comparison with publicly available data for the Hibernia it is assumed that this estimate refers to expenditure benefits from capital expenditures up to first oil.[8] This assumption is also consistent with the proponent’s response to question 7.2 in the Hebron Public Review Additional Information Request.[9]

Figure 16 profiles the Hibernia local expenditures captured by jurisdiction as reported in the C-NLOPB annual reports. The local expenditure captured by Newfoundland and Labrador to first oil was 47%. The corresponding estimate for other Canada was 25%, for a total Canadian benefit capture of 72%.

While the 44% reported for Hebron falls short of the 47% local content achieved for Hibernia, the range of expenditure captured by Newfoundland and Labrador would exceed this Hibernia estimate if the top of the range is achieved and fall short of it if the lower part of the range is manifested. Without further analysis than that which is provided in the Hebron Benefits Plan or in the Response to Hebron Public Review Additional Information Request, it is not possible to be more precise. Similarly, the same caveat applied to the other Canadian expenditure benefits capture estimates for the Hebron project. The range of benefits suggested by the proponent is wide enough to be consistent with a very low level of benefits captured (15%) and with an impressive level of benefit capture (30%), but the 23.5% estimate for the other Canadian estimate (23.5%) is very close to the Hibernia estimate (25%).

Although no specific analysis is provided,[10] the Hebron Benefits Plan (p. 4-27) suggests that “Of the total Project employment, it is estimated that 30 to 50 percent will occur in Newfoundland and Labrador, 15 to 25 percent will occur elsewhere in Canada, and 30 to 50 percent will occur outside of Canada.” While it is not clear whether this relates to total project costs or all capital costs or all capital costs to first oil, for the purpose of comparison with publicly available data for the Hibernia it is assumed that this estimate refers to employment benefits from capital expenditures up to first oil. This assumption is also consistent

[7] In response to the Additional Information Request, the proponent indicated that the expected the Newfoundland and Labrador expenditure content is 44%, with a range of 35 to 55% and Canadian expenditure content is 23.5%, with a range of 15 to 30%.

[8] Local expenditure capture by jurisdiction for Hibernia is available from the C-NLOPB’s annual reports (various years.

[9] In their response to whether the expenditure estimates relate to pre-production capital expenditure, the response from the Hebron proponent is that “These refer to the pre-production CAPEX (i.e., the construction phase.”

[10] In response to the Additional Information Request, the proponent indicated that the expected the Newfoundland and Labrador employment content is 40%, with a range of 30 to 50% and Canadian employment content is 20%, with a range of 15 to 25%.

with the proponent's response to question 8.2 in the Hebron Public Review Additional Information Request.[11]

Figure 17 profiles the local employment captured by jurisdiction as reported in the C-NLOPB annual reports. The local Hibernia employment captured by Newfoundland and Labrador to first oil was 66%. The corresponding estimate for other Canada was 12%, for a total Canadian benefit capture of 78%.

While the 40% local employment estimate for the Hebron is below the 66% achieved for Hibernia, the range of Hebron employment captured by Newfoundland and Labrador would fall short of the Hibernia estimate, even if the top of the range (50%) is achieved. The other Canadian employment estimate for Hebron of 20% and the range of 15% to 25% exceeds the 12% achieved for Hibernia.

Figure 16: Local Expenditure Benefits for Hibernia

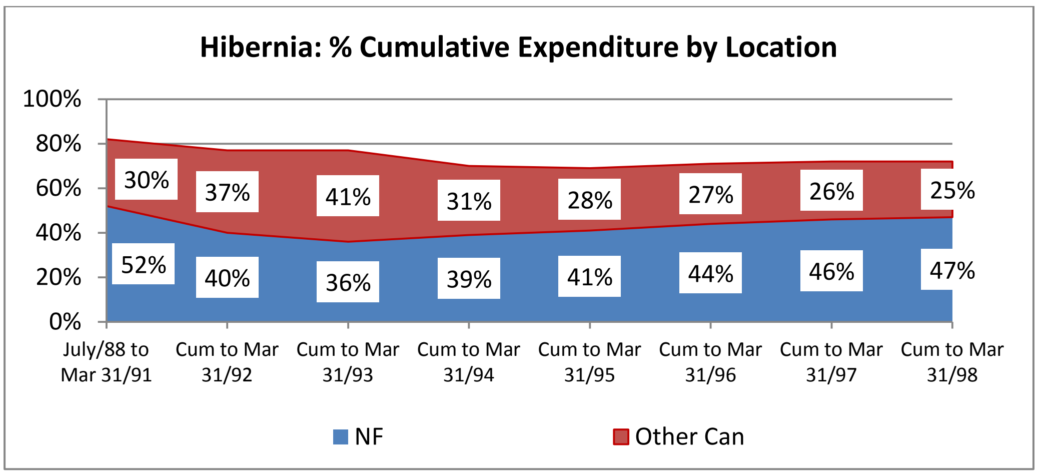
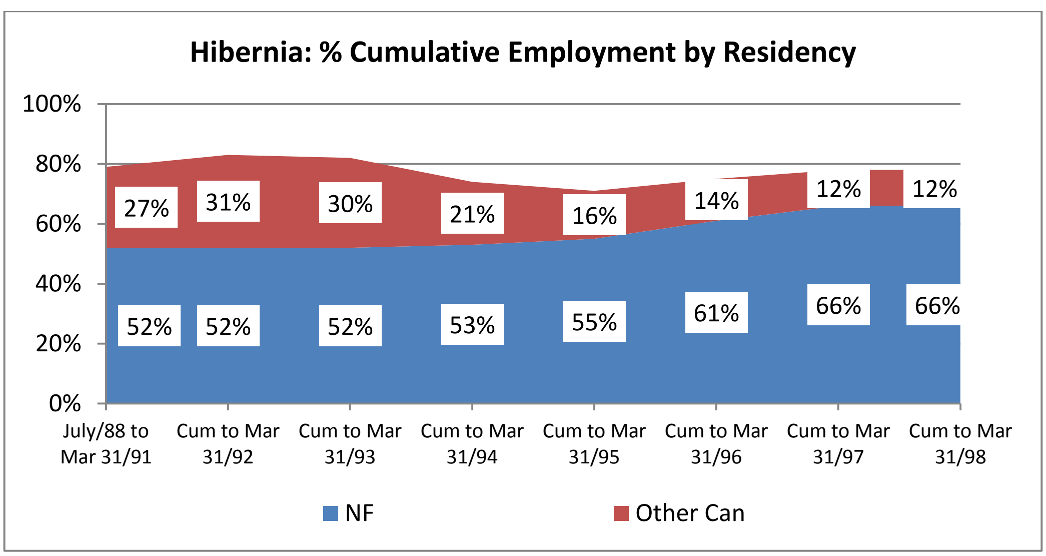


Figure 17: Local Employment Benefits for Hibernia



[11] In their response to whether the expenditure estimates relate to pre-production capital employment, the response from the Hebron proponent is that "These expenditures relate to the pre-production CAPEX."

6. Cost Comparison – Hebron to Hibernia

As part of comparing Hibernia to Hebron, this analysis examines the capital costs to first oil that was assumed to be relevant at the time of deciding whether to proceed with each project. The Hibernia project has evolved and grown over time in terms of both cost and recoverable reserves. For example, recoverable reserves were reported as greater than 500 million barrels in the C-NLOPB's 1985-86 annual report. This had increased to 666 million barrels in the 1988-89 C-NLOPB annual report; had increased again to 884 million barrels in the 1999-2000 annual report, was revised down to 865 million barrels in the 2002-03 annual report; increased to 1,244 million barrels in the 2005-06 annual report; and to 1,395 million barrels in the 2010-11 annual report. Similarly, the 1988-89 report put pre-production capital cost at $5.2 billion, which was raised to $5.6 B in the 1989-90 annual report and to $5.8 billion in the 1994-95 annual report.

For the purpose of this comparison, $5.6 Hibernia billion pre-production capital cost estimate was combined with the 666 million barrels of recoverable reserve estimate to yield a cost per barrel of $8.41 (1988 dollars). Adjusting this estimate for inflation that has occurred requires multiplying the estimate by 1.5793 (based on the change in the Canadian Consumer Price Index). Carrying out this adjustment yields a pre-production capital cost of $13.43 per barrel (2009 dollars).

The Hebron pre-production capital cost for the main field development is $6,705 million and the recoverable reserves without Pool 3 would be 645 million barrels. This implies that the pre-production capital cost is $10.40 per barrel (2009 dollars). The pre-production capital costs for the full field development (i.e., including Pool 3) is $7,604 million and the recoverable reserves are 769 million barrels, for a pre-production capital cost of $9.89 per barrel (2009 dollars).

While Hibernia's relative financial attractiveness has increased since the first decision to proceed, Hebron appears more attractive currently than Hibernia was in 1990 when the decision to proceed was taken.

7. Royalty Comparison – The Importance of Hebron

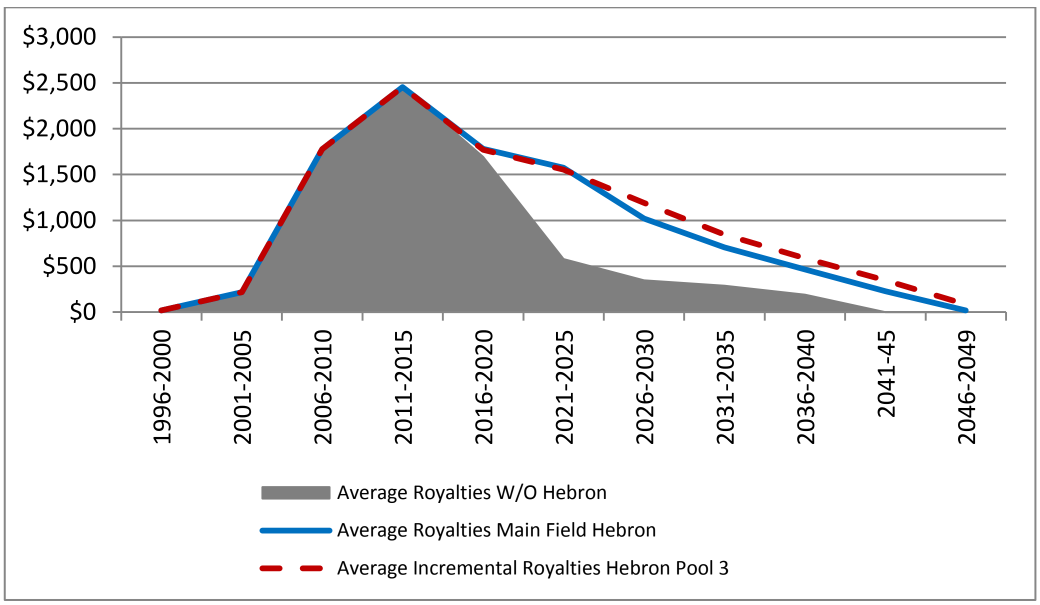
Not only will Hebron be important for the continuation of offshore production, as Table 12 and Figure 18 show, it will have a substantial and significant impact on provincial royalties at a time when the revenues expected to flow for the three existing projects are in decline. In particular, when Hebron's contribution is at its peak, it will represent between 60 and 70% of all oil royalties flowing to the provincial treasury. By way of further illustration, within 10 years of commencing production, the average royalties received by Newfoundland and Labrador from the existing projects is expected to fall to $580 million per year, but with the impact of the Hebron project included, provincial royalties are expected to be nearly $1.6 billion per year.

In other words, having Hebron continue to production is crucial to the long term fiscal health of Newfoundland and Labrador.

Table 12: Provincial Royalties With and Without Hebron

	Average Royalties W/O Hebron	Average Royalties Main Field Hebron	Average Incremental Royalties Hebron Pool 3	Royalties W/O Hebron	Royalties Main Field Hebron	Incremental Royalties Hebron Pool 3	Combined Hebron as a Percent of Total Royalties
1996-2000	$18			$72			
2001-2005	$218			$1,092			
2006-2010	$1,777			$8,885			
2011-2015	$2,452			$12,262			
2016-2020	$1,693	$88	-$12	$8,466	$442	-$60	4.3%
2021-2025	$579	$997	-$23	$2,894	$4,986	-$113	62.7%
2026-2030	$347	$674	$170	$1,736	$3,370	$848	70.8%
2031-2035	$288	$417	$141	$1,442	$2,087	$704	65.9%
2036-2040	$191	$276	$121	$954	$1,379	$606	67.5%
2041-45	$0	$230	$117	$0	$1,148	$585	100.0%
2046-2049	$0	$17	$68	$0	$68	$271	100.0%
Total				**$37,803**	**$13,479**	**$2,840**	**30.2%**

Figure 18: Provincial Royalties With and Without Hebron



8. Conclusion

The Hebron project will make a significant contribution to the continuity of offshore production in Newfoundland and Labrador; to provincial royalties; to R&D activities within the province and to employment and business activities located within the province. At prices that are expected to prevail in the future, this project should continue to be viable and it can sustain small increases in costs, but if those costs are as a result of benefits requirements, it is important to recognize that they come at a trade-off. Specifically, higher cost will be associated with lower royalties.