APPENDIX Q
Review of the Potential Economic and Fiscal Impacts of a 480-Well Development Scenario

Review of the Potential Economic and Fiscal Impacts of a 480-Well Development Scenario

Submission to Memorial University
in Support of the Newfoundland & Labrador
Hydraulic Fracturing Review Panel

Barry Rodgers
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EXECUTIVE SUMMARY

This report provides estimates of the economic viability of potential oil development and production on the West coast of the province of Newfoundland & Labrador (NL); specifically that associated with Shoal Point Energy's proposed Green Point Shale prospect.

This report provides base case economic analysis results for:

- Three recoverable reserves volumes:
  - 100 MM bbls (MM bbls – millions barrels)
  - 150 MM bbls
  - 200 MM bbls
- Three Brent-reference crude oil price scenarios:
  - USD $50/bbl (United States dollars $50 per barrel)
  - USD $85/bbl
  - USD $100/bbl and,
- Two waste water disposal options:
  - Deep Well Injection (DW-Inj)
  - Off-Site Transport and Treatment (OSTT).

In addition to the base-case results, sensitivity analysis results are provided for:

- A 25% decrease and a 50% increase in the cost of drilling and completing (D&C) crude oil production wells;
- An additional $100 MM capital expenditure by the developer for new road construction before the start of production;
- A potential socio-economic/environmental impact fee; sensitivities of 1%, 2%, and 3%;
- Investor discount rate, including a rate of 20%; and,
- United States to Canadian dollar exchange rate; 0.80, 0.90 (base assumption), and 1.00.

A general sensitivity analysis is also conducted for possible changes in crude oil price, recoverable reserves, capital costs, and operating costs.

The much higher costs associated with waste water disposal, if the DW-Inj option cannot be used, causes a substantial reduction in the project's economic prospects.

Within the recoverable reserves range analyzed, commodity price and waste water disposal are shown to be the most critical concerns. For prices at the USD $50/bbl level, all cases are uneconomic under the off-site transport and treatment waste water disposal option.

Currency exchange rate is also shown to be significant. For example, an exchange rate change from 1.00 to 0.80 doubles the NPV for the 100 MM bbls DW-Inj case at $85/bbl.

Drilling and completion costs are of course important. The results show that all but one case (100 MM bbls with OSTT) would be economically viable at a price of $85/bbl, even if D&C costs were to be 50% higher than those of the base case. However, if price were $50/bbl, even the base cases are shown to be mostly uneconomic.

An additional $100 MM infrastructure investment in the first year of the cash flow before the start of production results in a marginal reduction in project NPV for the lower cost DW-Inj option. However, the low 100 MM bbl with OSTT case would be changed from marginal to sub economic.

Analysis shows that, even at a 20% discount rate, both waste water disposal options would be economically viable with the 150 MM bbls reserves at the $85/bbl price. At the $50/bbl price level neither of these cases would be economically viable.

The analysis highlights that any new levies, such as a potential environmental charge, should be designed to complement the overall fiscal system.

Overall, the analysis shows that the project faces considerable risks to economic viability. However, the analysis does indicate potentially attractive project economics, even after accounting for geological and development risks.[1] This does not necessarily mean that full scale project investments should necessarily be made at this time. It does mean that the project appears to be attractive enough to proceed to the next stage, and consider drilling another well with the hope of better understanding the risks as well as confirming the reserve size estimates and costs.

1 BACKGROUND AND PURPOSE

1a. Introduction

The Government of Newfoundland and Labrador, through the Ministry of Natural Resources and in cooperation with Memorial University, has appointed an independent Panel – the Newfoundland and Labrador Hydraulic Fracturing Review Panel (Panel).[2]

The Panel is conducting "... a public review of the socio-economic and environmental implications of hydraulic fracturing in Western Newfoundland. The mandate of the Panel ... [includes making] recommendations on whether or not hydraulic fracturing should be undertaken in Western Newfoundland".[3]

This report provides estimates of the economic viability of potential oil development and production on the West coast of the province; specifically that associated with Shoal Point Energy's proposed Green Point Shale prospect.

The purpose of the report is to help inform the recommendations of the Panel with respect to the likelihood that developments would be economically significant and contribute potential direct government revenues.

This report provides base case economic analysis results for:

- Three recoverable reserves volumes:
  - 100 MM bbls (MM bbls – millions barrels)
  - 150 MM bbls
  - 200 MM bbls
- Three Brent-reference crude oil price scenarios:
  - USD $50/bbl
  - USD $85/bbl
  - USD $100/bbl and,
- Two waste water disposal options:
  - Deep Well Injection (DW-Inj)
  - Off-Site Transport and Treatment (OSTT).

In addition to the base-case results, sensitivity analysis results are provided for:

- A 25% decrease and a 50% increase in the cost of drilling and completing crude oil production wells;
- An additional $100 MM capital expenditure by the developer for new road construction before the start of production;
- A potential socio-economic/environmental impact fee; sensitivities of 1%, 2% and 3%;
- Investor discount rate, including a rate of 20%; and,
- United States to Canadian dollar exchange rate; 0.80, 0.90 (base assumption), and 1.00.

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[1] Geological risk in this report refers only to the risk that the reserve sizes modeled will be found.
[2] Further information on the Panel is provided at the following web address: nlhfrp.ca/
[3] The Panel's Terms of Reference can be found at: nlhfrp.ca/terms-of-reference/

A general sensitivity analysis is also conducted for possible changes in crude oil price, recoverable reserves, capital costs, and operating costs.

Six annexes are included as follows:
Annex 1: Scope of Work
Annex 2: Cash Flow Model Description
Annex 3: Fiscal Terms Description
Annex 4: Fiscal Audit Calculations
Annex 5: Annual Cash Flows – Nominal & Real
Annex 6: New R-Factor Fiscal Terms – Preliminary Economic Results

1b. Shoal Point Energy

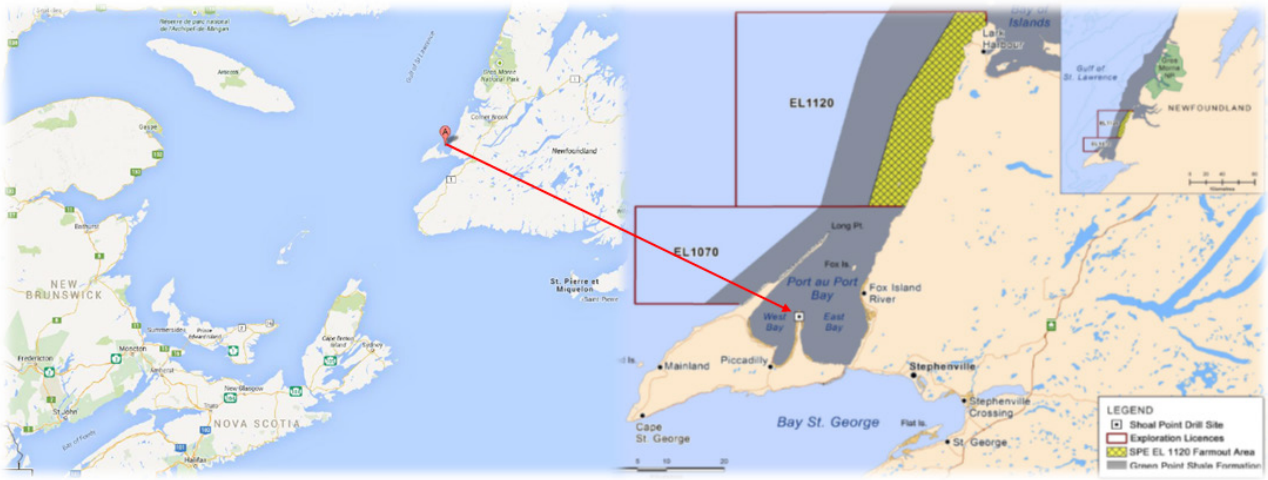
Shoal Point Energy Ltd. (SPE) is a petroleum exploration and development company with offices in Toronto, Ontario and Vancouver, British Columbia. The Company is dedicated to the exploration of the Green Point Shale which it believes is one of the largest undeveloped oil resources in North America.[4]

Information published by the Canadian Securities Exchange (CSE) describes Shoal Point Energy as:

> *... a public company with a 100% interest in the shallow rights in Exploration License EL#1070 [refer to Figure 1b.1 below] in the Province of Newfoundland comprising approximately 150,000 acres of oil-in-shale in Port au Port Bay and which can be developed almost entirely from land. In addition, Shoal Point has an agreement to earn a net 80% interest in the 67,298 acres of Green Point Shale (shallow rights) of EL #1120 which is owned by Ptarmigan Energy Inc. [See the green shaded area of Figure 1b.1]. The total potential gross acreage in the Green Point Shale is approximately 220,000 acres.*[5]

Under the agreement with Ptarmigan SPE must drill and test a well that must be spudded by January 15, 2016.[6]

Figure 1b.1. Green Point Shale – geographic context.



[4] Shoal Point Energy: www.shoalpointenergy.com/overview.php
[5] Canadian Securities Exchange: www.cnsx.ca/CNSX/Securities/Oil-and-Gas/Shoal-Point-Energy-Ltd.aspx
[6] Shoal Point Energy Ltd.: www.shoalpointenergy.com/pdfs/SHPMDAAPR302015.pdf

1c. Historical Context – Wells Drilled

One hundred fourteen (114) wells have been drilled in search of hydrocarbons on NL's West coast. Sixty four (64) were drilled between the first in 1867 by John Silver at Parsons Pond and BHP Petroleum's 1991 well at Port au Choix. Although most of these wells encountered hydrocarbons, only the 1991 Garden Hill Port au Port #1 well on the Port au Port Peninsula was successful in achieving limited hydrocarbon production.

Since that time an additional fifty (50) wells have been drilled – forty (40) onshore, nine (9) from onshore to offshore, and one (1) offshore.[7]

1d. The Green Point Shale

Geologically, the island of Newfoundland is divided into three areas or zones – the Western (or Humber) Zone, the Central Zone, and the Eastern Zone (Figure 1d.1).

Figure 1d.1. Geological Zones – Newfoundland Island.

The Green Point Formation is part of the Cow Head Group within the Anticosti Basin on the Province's West coast – see Figure 1d.2. While the Humber Zone is an onshore classification, the Green Point Shale extends into the offshore.

> *The term "Green Point shale" ... is a name sometimes informally given to shale layers in western Newfoundland that either are known to be, or are inferred to be, part of the Green Point Formation. ... In the Port au Port region, shale layers occur as part of the Cow Head Group. That shale has been correlated with the Green Point Formation, ... Shale has been encountered in exploration wells off the west coast of Newfoundland, where the Green Point Formation is also projected to occur below the sea floor, from south of Bonne Bay to Bay of Islands and into Port au Port Bay.*[8]

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7 Larry Hicks and Jillian Owens, *The History of Petroleum Exploration in Western Newfoundland*, Department of Natural Resources, Energy Branch, Government of Newfoundland and Labrador.

8 A.M. Hinchey; I. Knight; G. Kilfoil; K.T. Hynes; D. Middleton; L.G. Hicks, *The Green Point Shale of Western Newfoundland*, Department of Natural Resources, Government of Newfoundland and Labrador.

Figure 1d.2. Anticosti Basin – Western Newfoundland.

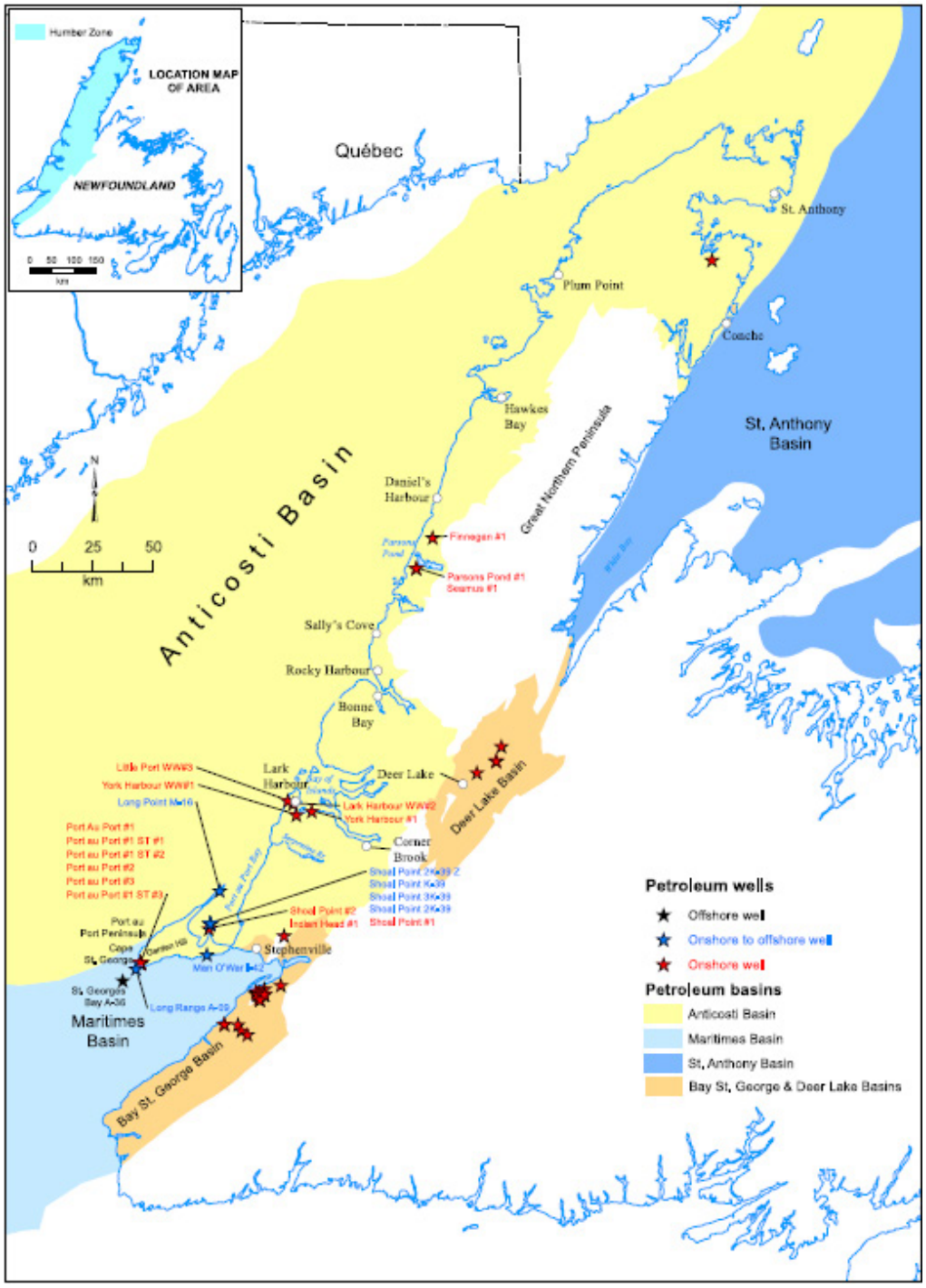
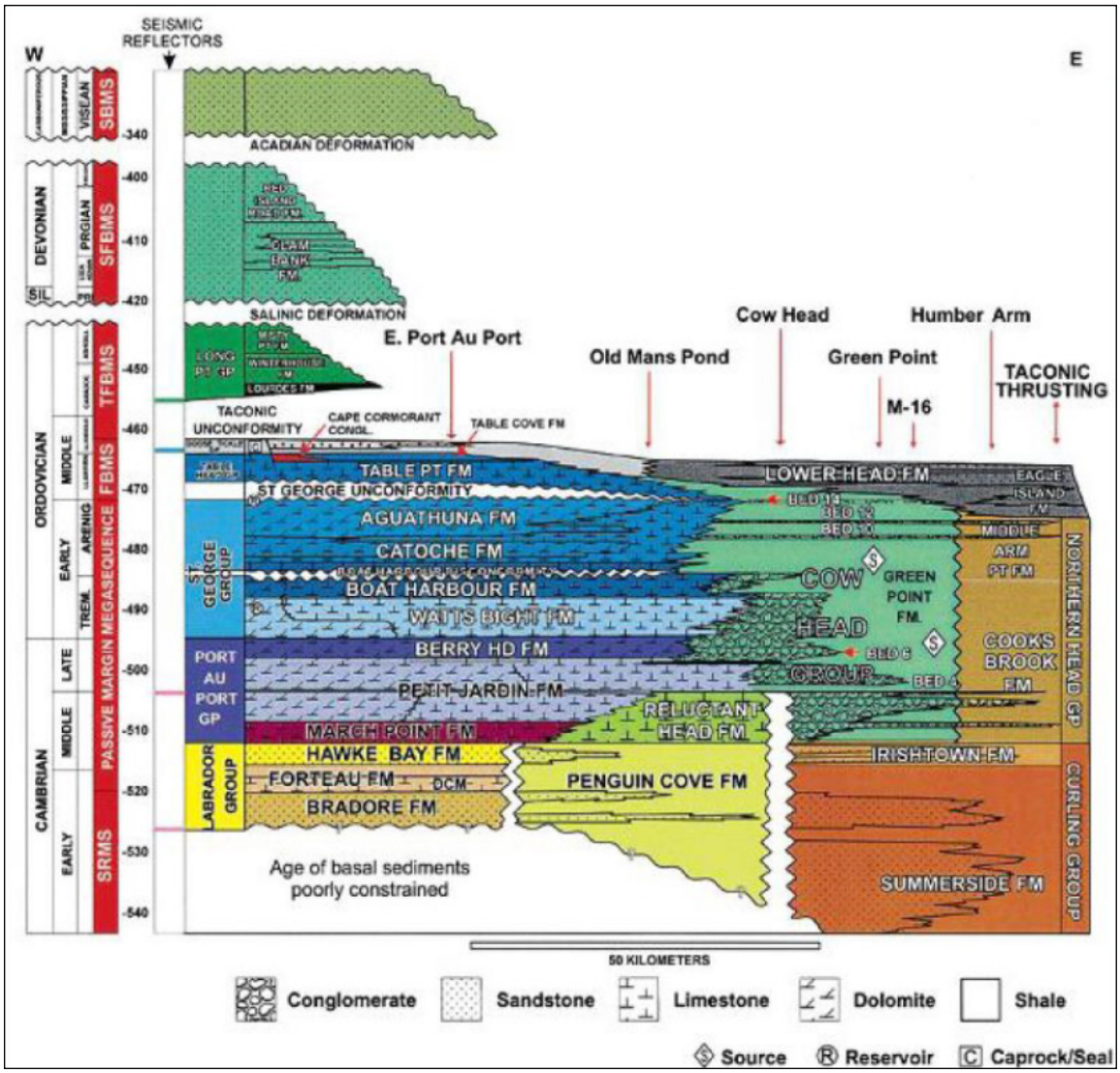


Figure 1d.3 shows the Green Point Formation in the context of the surrounding lithology.

Figure 1d.3. Green Point Shale lithology.



1e. Technology and Unconventional Resources

The shale oil/gas revolution is based on two key technologies – horizontal drilling and hydraulic fracturing.

Oil and gas are typically described as occurring in "pools" that are found deep underground. These "pools" are actually porous rock – rock with tiny connected pore spaces that contain oil or natural gas. One common example of such rock is sandstone. An analogy often used is that of a sponge where the oil or gas saturates the sandstone.

Pools in which wells can be drilled so that oil and natural gas flow naturally or can be pumped to the surface are commonly referred to as "conventional" resources or developments.

The Green Point Shale is considered an unconventional resource. Unlike the oil and gas in conventional pools, unconventional oil and natural gas do not flow easily through the rock, making them much more difficult to produce.

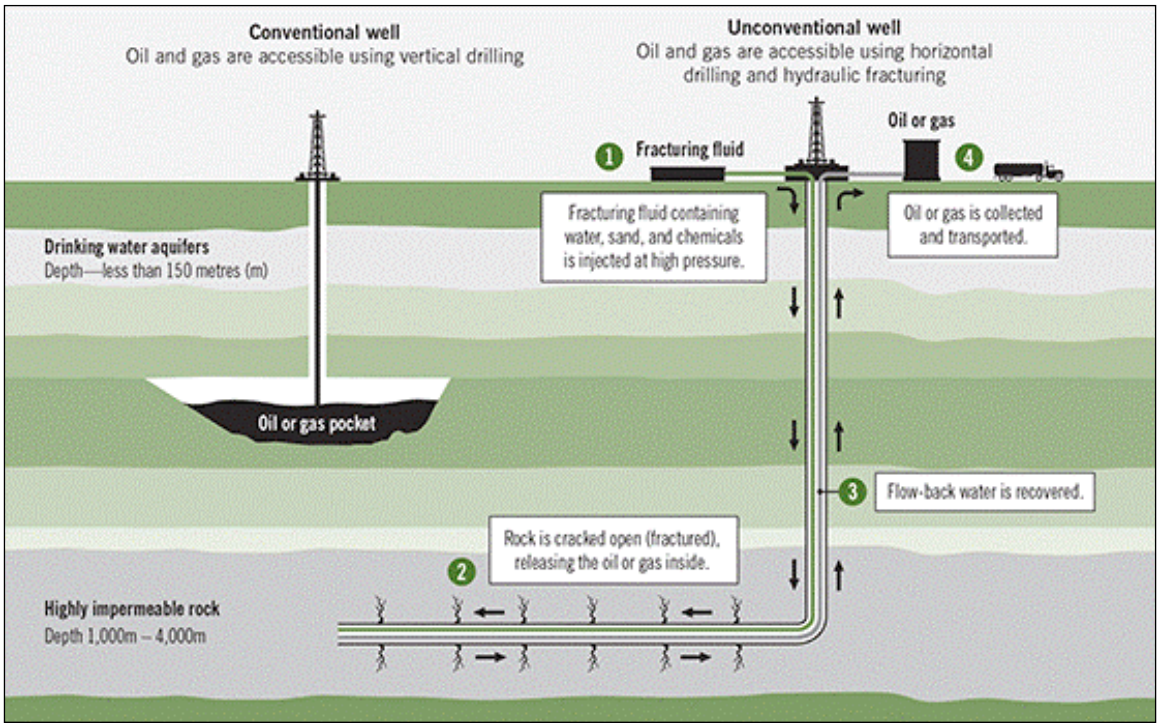
On this basis, unconventional resources are described as those resources in low permeability rock where the pores are not very well connected, making it difficult for oil and natural gas to move through the rock to the well.

Distinction between unconventional vs. conventional resources is often a reference to the technology used to extract the oil or gas.

Production from low permeable formations is made possible with the new technology of hydraulic fracturing, or 'fracking'. Fracking opens pathways in the formation that enable the oil and gas to move to the well.

Figure 1e.1 shows conventional resources to be more associated with vertical wells, with unconventional resources associated with horizontal wells. Horizontal drilling allows a much larger portion of the well bore to intersect the hydrocarbon formation, thereby enhancing resource recovery and well productivity.

Figure 1e.1. Conventional and unconventional wells.



The combination of hydraulic fracturing and advances in horizontal drilling has allowed oil and natural gas companies to produce resources that were previously impossible to obtain.

While horizontal and hydraulic fractured wells are significantly more costly than conventional vertical wells, the increased productivity and resource recovery result in significantly improved investment economics.

Note that Figure 1e.1 above identifies the injection of *fracking fluid* and the recovery of *flow-back water*; these are discussed further below.

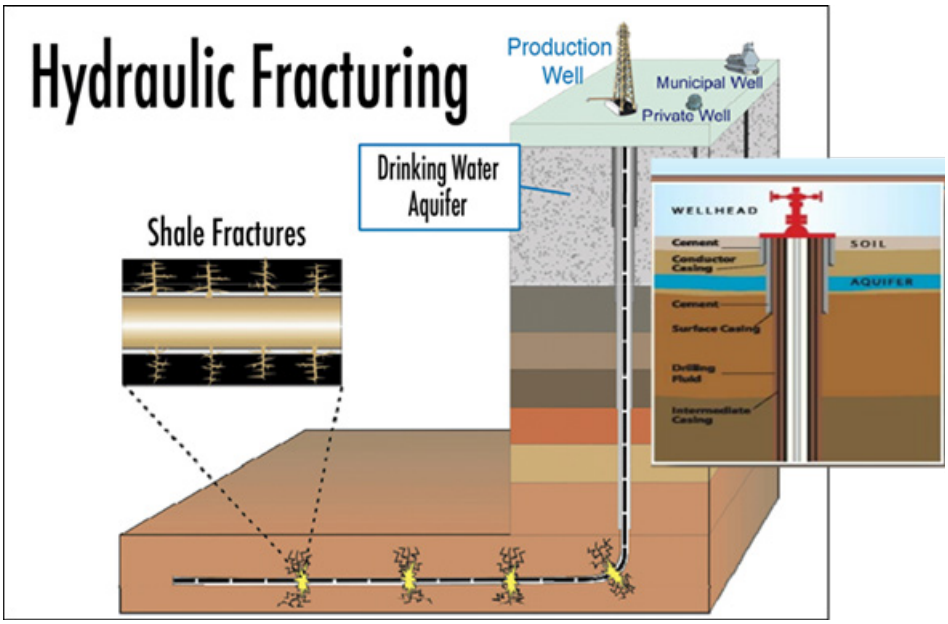
1f. Hydraulic Fracturing

Hydraulic fracturing – fracking – is the process of pumping fluid into a wellbore at an injection pressure that is high enough to break, or fracture, the rock formation. These fractures (fracks) create pathways for the oil or gas to flow to the well bore.

The fluid is first injected into the well before any solids or proppants are added. This injection continues until the underground rock is shattered or cracked and the fractures are wide enough to accept a propping agent, sand or ceramic beads. The purpose of the propping agent is to keep apart the fracture surfaces once the pumping operation ceases.[9]

Figure 1f.1 illustrates hydraulic fracturing, showing also the relationship between the well bore, the fresh water aquifer, and the fracked hydrocarbon-bearing formation.

Figure 1f.1. Hydraulic fracturing.



The illustration shows the hydrocarbon formation to be far below the fresh water aquifer. Aquifer contamination is prevented by layers of impermeable rock that are typically thousands of feet thick between the aquifer and the hydrocarbon formation. Possible contamination where the drill pipe passes through the aquifer is prevented by steel casing that is cemented into place, thereby again separating the aquifer from the injection and production fluids.

[9] petrowiki.org/Hydraulic_fracturing

1g. The Fracking Fluid

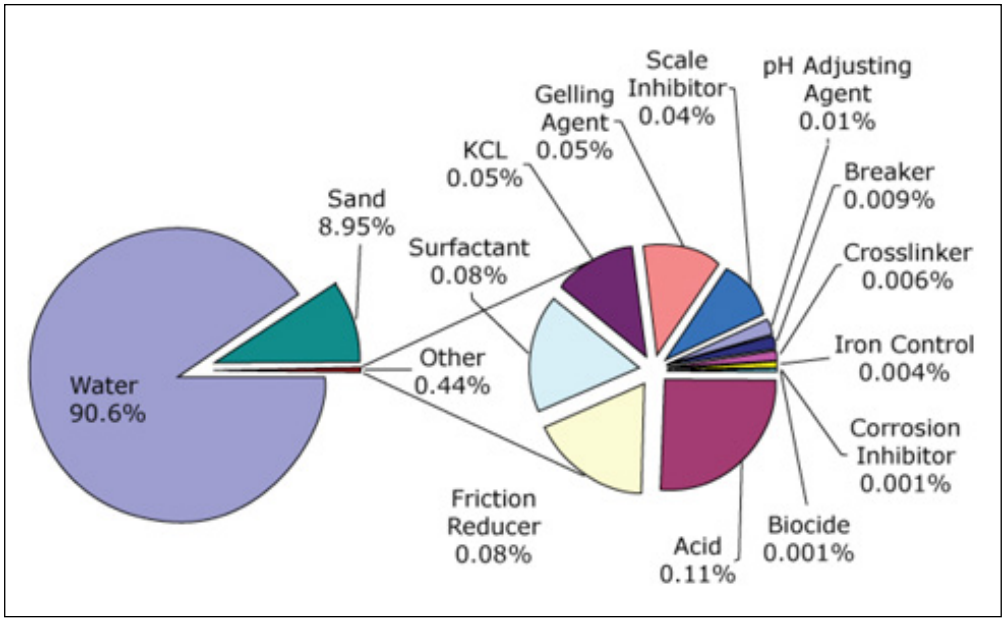
The huge volumes of water required, and the chemical composition of this water, make unconventional reservoir fracking a unique concern. While a conventional oil well may require 100-400 m^3 of water, the water usage increases to 1,000-30,000 m^3 (2.4-7.8 million U.S. gallons) for a hydraulic fracturing well.[10,11,12]

The fracking fluid, often referred to as 'slick-water' is typically 98.0%-99.5% plain water; the remaining fluid consists of a variety of chemical additives, including detergents, salts, acids, alcohols, lubricants and disinfectants. Figure 1g.1 illustrates the composition of the slick-water fluid.

Following the completion of the fracking process, trapped reservoirs of gas and oil are released and pumped back to the surface, along with millions of gallons of "flow-back" or waste water. The flow-back water is recovered from the well and must then be treated and safely disposed.

The flow-back water contains a number of additional contaminants, including radioactive material, heavy metals, hydrocarbons, and other toxins picked up from the earth. The flow-back water is temporarily stored at the fracking site in pits for subsequent injection deep underground or disposal off-site at a waste-water treatment facility.[13]

Figure 1g.1. Slick-water composition.



All oil and gas drilling requires the treatment and disposal of contaminated water. Because of the large volumes of waste-water associated with fracking operations the cost of water handling is much higher for these wells. Due to the increased significance of this cost and the absolute necessity that this water be safely disposed, this report includes duplicate scenario to illustrate the impact of off-site waste water disposal on project economics.

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10 Canadian Society for Unconventional Resources – www.csur.com/sites/default/files/Understanding_Water_final.pdf

11 Jeffery M. Reynolds, James "Chip" Northrup, *Frack Truck Impacts on New York Villages and Towns* – www.otsego2000.org/documents/FrackingShaleTrucks.pdf

12 For comparison, the volume of the Windsor Lake reservoir near St. John's is 20,000 m^3: www.stjohns.ca/living-st-johns/city-services/water-services/water-reservoirs

13 www.livescience.com/34464-what-is-fracking.html

1h. Socio-Economic Considerations

While the drilling, slick-water fluid injection, and flow-back water treatment operations are familiar to those performing them, they are none-the-less real concerns for many people, particularly those unaccustomed to oil and gas drilling activities.

In addition to the sourcing of the water requirements and the treatment and disposal of waste water, other socio-economic concerns with fracking operations include, the possible contamination of drinking water, and the increased community disruption and call on existing infrastructure resulting from drilling, fracking, and water disposal operations. For example, the tanker truck traffic to bring the water to the drill sites and take away the waste water might include 900-1,400 tanker truck loads per well.[14]

There are potential significant, and even prohibitive, costs if these activities are not adequately regulated. While consideration of these costs and the associated regulatory requirements are beyond the scope of this report, they are being addressed by the Panel.

2 PROJECT DESCRIPTION

2a. Recoverable Reserves and Production Profiles

In May 2014 Shoal Point Energy requested Morning Star Consultants, LLC (Morning Star) to prepare "… an independent estimate of the potential gross reserves for certain leasehold interests of Shoal Point Energy, Ltd. (Shoal Point Energy). The properties included within this evaluation are comprised of Blocks EL 1070 and EL 1120 … "[15]

Morning Star concluded that estimated "prospective resources" (hereafter referred to as estimated ultimate recoverable reserves – EUR) for the two exploration licenses (EL 1070 and EL 1120) could range from a Low of 177.3 million barrels (MM bbls) to a High of 908.6 MM bbls, with a "Best" estimate of 428.4 MM bbls.[16] These Low, Best, and High estimates alternatively reflect their estimated probability of occurrence, respectively referenced as the P_{90}, P_{50}, and P_{10} estimates.[17]

In preparation for the current report, discussion with the Panel resulted in a focus only on EL 1070 and only on that portion of the reserves that could be reached from wells drilled from onshore. This modified the recoverable reserves estimates to a range of 100-200 MM bbls, with the best guess estimate at 150 MM bbls.[18]

While all resource plays exhibit different characteristics, loose comparability with the Bakken play in North Dakota is thought to be reasonable at this stage in developing production profiles for each reserves case. As such, the profile is assumed to follow a hyperbolic decline. Based on the 2014 Bakken region drilling productivity decline model for horizontal wells in the Bakken formation, the following parameters are used to determine the production profile for a typical well: Initial well productivity (IP) at 400 barrels of oil per day (bopd), a decline percentage (D%) of 75%, and a "b"

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[14] This would imply 1,800 – 2,800 truck drive-bys as per Jeffery M. Reynolds, James "Chip" Northrup – see above reference.

[15] Morning Star Report – www.shoalpointenergy.com/pdfs/MorningstarNI51-101%20Report%20Shoal%20Point%20%20v%20%20%20 6-10-2014.pdf

[16] Morning Star Report, page 19.

[17] P_{90} refers to a 90% probability that the EUR will be at least a certain value, in this case 100 MM bbls; similarly P_{10} indicates a 10% chance that the EUR will be 200 MM bbls.

[18] These estimates are based on the Morning Star report and discussions with the Panel.

factor exponent of 0.14.[19,20]

With the well life assumed to be 20 years, the IP and decline parameters result in per-well EUR's of 288,333 bbls, 312,500 bbls, and 416,667 bbls respectively, for the P_{90}, P_{50}, and P_{10} cases. The associated production profiles are provided in Table 2a.1.

A Gas/Oil Ratio (GOR) of 500 standard cubic feet (scf) per bbl is used to determine the gas production.[21] Produced gas will be used to generate electricity for onsite operations.

It is assumed that 480 production wells will be needed to fully exploit each EUR case.

Table 2a.1 shows the per-well oil and associated gas production profiles for each reserves case. The profiles for the full-field cases are presented in Table 2a.2. Figures 2a.1 and 2a.2 illustrate the oil production profiles, respectively for the wells and the full field cases.

Table 2a.1. Well production profiles – oil and gas.

Green Point Shale Well Production Profiles						
	Low EUR Case 100 MM bbls		Base EUR Case 150 MM bbls		High EUR Case 200 MM bbls	
	Crude Oil	Associated Gas	Crude Oil	Associated Gas	Crude Oil	Associated Gas
Year	bbls	MMcf	bbls	MMcf	bbls	MMcf
1	97,400.00	48.70	146,100.00	73.05	194,800.00	97.40
2	47,921.47	23.96	71,882.20	35.94	95,842.93	47.92
3	25,305.82	12.65	37,958.73	18.98	50,611.64	25.31
4	14,159.72	7.08	21,239.58	10.62	28,319.44	14.16
5	8,314.76	4.16	12,472.14	6.24	16,629.52	8.31
6	5,086.12	2.54	7,629.19	3.81	10,172.25	5.09
7	3,222.08	1.61	4,833.12	2.42	6,444.16	3.22
8	2,104.13	1.05	3,156.20	1.58	4,208.26	2.10
9	1,411.08	0.71	2,116.62	1.06	2,822.16	1.41
10	968.76	0.48	1,453.14	0.73	1,937.52	0.97
11	679.11	0.34	1,018.66	0.51	1,358.21	0.68
12	485.02	0.24	727.54	0.36	970.05	0.49
13	352.28	0.18	528.42	0.26	704.56	0.35
14	259.78	0.13	389.67	0.19	519.56	0.26
15	194.24	0.10	291.36	0.15	388.48	0.19
16	147.08	0.07	220.61	0.11	294.15	0.15
17	112.66	0.06	168.99	0.08	225.32	0.11
18	87.22	0.04	130.83	0.07	174.45	0.09
19	68.20	0.03	102.29	0.05	136.39	0.07
20	53.81	0.03	80.71	0.04	107.61	0.05
	208,333.33	104.17	312,500.00	156.25	416,666.67	208.33
Rodgers Oil & Gas Consulting, after discussion with the Panel						

[19] Energy Information Administration (EIA) – 2014 Bakken Region Drilling Productivity Report: www.eia.gov/petroleum/drilling/archive/dpr_aug14.pdf

[20] United States Geological Survey – Procedure for Calculating Estimated Ultimate Recoveries of Bakken and Three Forks Formations Horizontal Wells in the Williston Basin: pubs.usgs.gov/of/2013/1109/OF13-1109.pdf

[21] GOR based on Beggs Standing's Correlation equation Pg. 35 of (B.C. Craft, M. Hawkins, Revised by Ronald E. Terry, "Applied Petroleum Reservoir Engineering" 1991), and DST test for Shoal Point K-39 well (NRCAN: basin.gdr.nrcan.gc.ca/wells/single_testing_e.php?well=N159&test=0#test)

Figure 2a.1. Green Point Shale – well production profiles – crude oil.

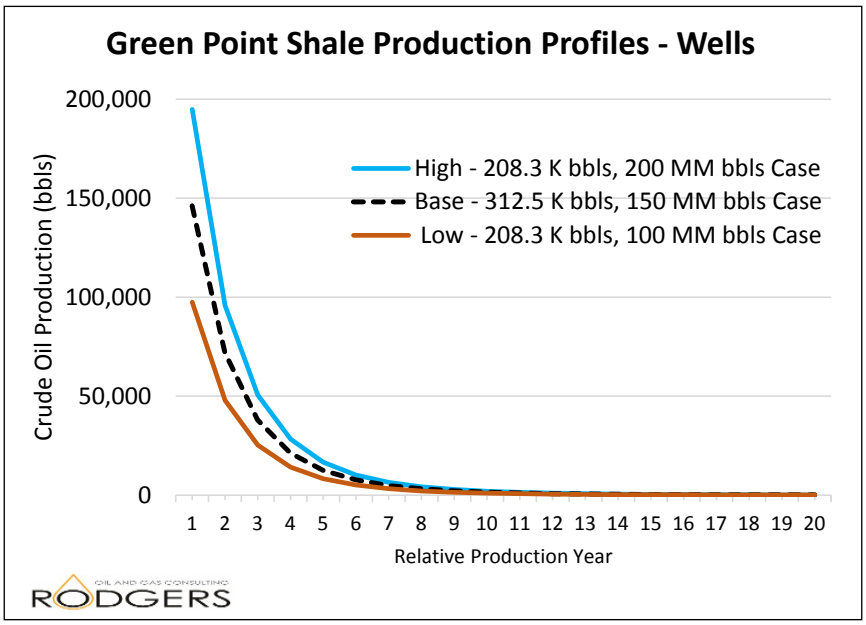
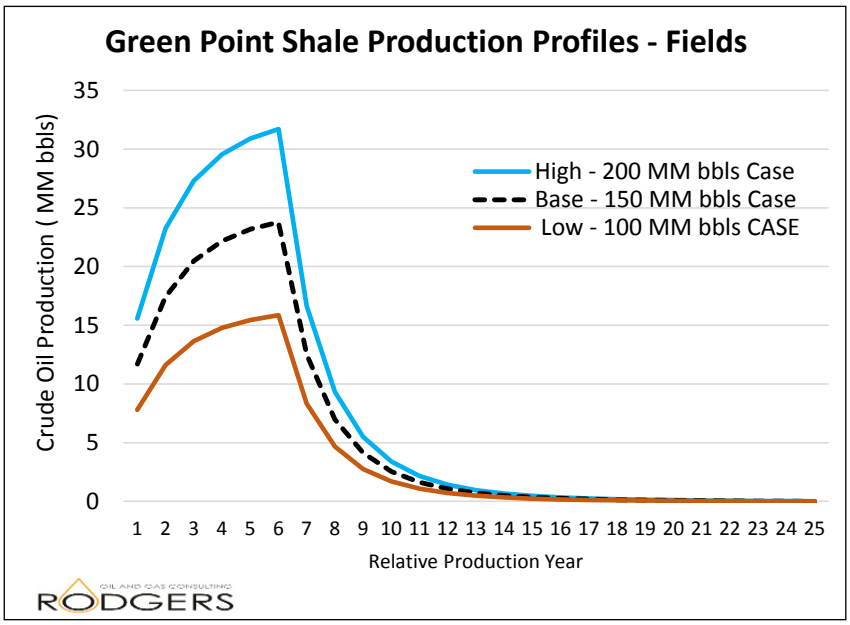


Table 2a.2. Field production profiles – oil and gas.

Green Point Shale Field Production Profiles						
	Low EUR Case 100 MM bbls		Base EUR Case 150 MM bbls		High EUR Case 200 MM bbls	
	Crude Oil	Associated Gas	Crude Oil	Associated Gas	Crude Oil	Associated Gas
Year	MM bbls	Bcf	MM bbls	Bcf	MM bbls	Bcf
1	7.792	3.90	11.688	5.84	15.584	7.79
2	11.626	5.81	17.439	8.72	23.251	11.63
3	13.650	6.83	20.475	10.24	27.300	13.65
4	14.783	7.39	22.174	11.09	29.566	14.78
5	15.448	7.72	23.172	11.59	30.896	15.45
6	15.855	7.93	23.783	11.89	31.710	15.86
7	8.321	4.16	12.481	6.24	16.642	8.32
8	4.655	2.33	6.983	3.49	9.311	4.66
9	2.744	1.37	4.116	2.06	5.488	2.74
10	1.689	0.84	2.533	1.27	3.377	1.69
11	1.078	0.54	1.617	0.81	2.155	1.08
12	0.710	0.35	1.064	0.53	1.419	0.71
13	0.480	0.24	0.720	0.36	0.960	0.48
14	0.332	0.17	0.499	0.25	0.665	0.33
15	0.235	0.12	0.353	0.18	0.470	0.24
16	0.169	0.08	0.254	0.13	0.339	0.17
17	0.124	0.06	0.186	0.09	0.248	0.12
18	0.092	0.05	0.138	0.07	0.185	0.09
19	0.070	0.03	0.104	0.05	0.139	0.07
20	0.053	0.03	0.080	0.04	0.106	0.05
21	0.038	0.02	0.056	0.03	0.075	0.04
22	0.026	0.01	0.039	0.02	0.052	0.03
23	0.017	0.01	0.025	0.01	0.033	0.02
24	0.010	0.00	0.015	0.01	0.020	0.01
25	0.004	0.00	0.006	0.00	0.009	0.00
	100.000	50.000	150.000	75.000	200.000	100.000
Rodgers Oil & Gas Consulting, after discussion with the Panel						

Figure 2a.2. Green Point Shale – field production profiles – crude oil.



2b. Development Concept

Field development facilities will be located onshore, with wells drilled from onshore to offshore locations underneath the seabed. Wells would be drilled to a vertical depth approximating 3,000 meters, with a horizontal section that could extend over 2 kilometers under the ocean floor. Facilities will include those for well drilling, liquids processing, water handling and waste-water storage, oil storage, electricity generation and distribution, and oil transportation.

2c. Unit Costs and Price

To provide context for considering the costs, the development or capital costs (CapEx) and operating costs (OpEx) estimates are expressed on a per-bbl basis so that they may be directly compared to the oil price.

Table 2c.1 provides a summary of the CapEx and OpEx on a per-barrel basis. Comparison with the oil price provides a first sense of whether the project is likely to be economically viable. For example, the 200 MM bbl deep well injection case at a cost of $25.42/bbl looks very attractive when compared to the high price case of $109.11/bbl; alternatively, the 100 MM bbl off-site transport and treatment case at a total cost of $73.90/bbl would be clearly uneconomic at the low price of $53.56/bbl.

Table 2c.1. Unit costs and price comparison.

Green Point Shale Base Case Unit Cost Estimates (CDN $/bbl)						
	Waste Water Disposal Option					
	Deep Well Injection (DW-Inj)			Off-Site Transport & Treatment (OSTT)		
per-bbl Estimates	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Capital Costs	40.83	27.22	20.42	40.28	26.85	20.14
Operating Costs	6.76	5.59	5.01	33.62	30.40	28.79
Total Costs [1]	47.60	32.81	25.42	73.90	57.25	48.93
Crude Oil Price [2]						
Low Price (USD $50)	53.56					
Base Price (USD $85)	92.44					
High Price (USD $100)	109.11					
1. Cost do not include financing, payments to governments, or a component for investor return						
2. Based on a United States/Canada exchange rate of 0.90 and a CND transport cost of $2.00/bbl; e.g. 85/0.90 - 2.00 = 92.44						
Rodgers Oil & Gas Consulting						

Table 2.c.2 identifies the estimated CapEx and OpEx in more detail. Other important assumptions are also identified, including the assumed oil price and currency exchange rate. Costs are categorized in order to facilitate project description and grouping for fiscal calculations. Crude transportation costs are identified in the pricing section below.

The production well drilling and completion cost assumption shown in the table represents the average based on an initial per well cost of $10 MM with efficiency improvements occurring over time, consistent with experience from other shale developments. Well cost reductions from improved efficiency are based on a 15% per year reduction for the first 5 years and 1% thereafter. [22,23,24,25]

For the deep well injection disposal option, the number of disposal wells for produced water and hydraulic fracture stimulation flow back water is assumed to be eight (8), with an average disposal capacity of 2,500 bbl/d per well and an average drilling and completion cost per disposal well facility of $9.3 MM.[26] The alternative off-site transport and treatment waste water disposal option needs only two (2) of the disposal wells.

Based on oil producing horizontal wells in the Middle Bakken formation completed in 2012-2015 (as of August 7th. 2015), the produced water ratio is assumed to be 0.77.[27]

Table 2c.2. Analysis assumptions – with waste water disposal options: deep well injection and off-site transport & treatment. (Rodgers Oil & Gas Consulting with input from the Panel – see page 19.)

[22] Market Realist. "Hess Corp. Bakken Well Cost Over Time", marketrealist.com/analysis/stock-analysis/energy-power/upsteam-oil-gas/charts/?featured_post=33667&featured_chart=33681

[23] DTC Energy Group Inc., "Bakken 5-Year Drilling & Completion Trend" 2013: www.dtcenergygroup.com/bakken-5-year-drilling-completion-trends/

[24] New Brunswick Onshore Oil and Natural Gas Well Abandonment Study: www.pr-ac.ca/files/files/WellAbandonment_RPT_02Nov04.pdf

[25] NL Onshore Area Historical Well Program Expenditures and Employment (1994-2013): nlhfrp.ca/wp-content/uploads/2015/01/Onshore-Area-Historical-Well-Program-Expenditures-and-Employment.pdf

[26] Fortress Environmental Services new Eagle Ford Shale Saltwater Disposal Well : www.fortressenviro.com/fortress-opens-9-3-million-eagle-ford-shale-saltwater-disposal-well-to-provide-the-hydraulic-fracturing-industry-with-an-environmentally-friendly-site-to-pump-produced-water-back-to-its-source/

[27] North Dakota Oil and Gas Division, Bakken Horizontal Wells by Producing Zone: www.dmr.nd.gov/oilgas/bakkenwells.asp

GREEN POINT SHALE ANALYSIS ASSUMPTIONS	Recoverable Reserves Case		
	Low	Base Case	High
Assumptions			
Estimated Recoverable Reserves (EUR) Oil	100 MM bbls	150 MM bbls	200 MM bbls
EUR per Well	208,333 bbls	312,500 bbls	414,667 bbls
Gas Oil Ratio (GOR)	Same as Base Case	500 scf/bbl	Same as Base Case
Price (USD $/bbl Brent)		$85/bbl	
Exchange Rate (USd $/CDN)		0.9	
Inflation Rate		2.0%	
Assumed Private Weighted Average Cost of Capital – Real		10.0%	
Assumed Private Weighted Average Cost of Capital – Nominal		12.2%	
Number of Wells		480	
Assumed Maximum Number of Wells Drilled per Year		80	
Assumed Well Life (Years)		20	
Number of Years for Drilling Production Wells		6	
Development Configuration – See Figure 9			
All facilities will be onland with wells drilled from onshore to offshore			
Cost Details – CapEx (CND $)			
Average cost per production well.	Same as Base Case	7,042,362.40	Same as Base Case
Total production well cost		3,380,333,950.00	
Water disposal wells (water injected)		74,400,000.00	
Central Processing Facilities & Main Gathering Lines		80,000,000.00	
Central Storage & Loading Facilities		120,000,000.00	
Field Oil & Gas Gathering Lines for 30 well-pad sites		34,285,714.29	
Field Oil & Gas Treatment Facilities		34,285,714.29	
Main Processed Gas Line		80,000,000.00	
Lease & Install 3.5 MW Gas to Electric Turbines		40,000,000.00	
Electricity Generation		40,000,000.00	
Marine Terminal		150,000,000.00	
Pre development		50,000,000.00	
Total CapEx – with Deep Well (DW-Inj)		**4,083,305,378.57**	
Total CapEx – with Off-Site Transport & Treatment (OSTT)		**4,027,505,378.57**	
Cost Details – OpEx (CND $)			
Field Oil Fixed Opex	40,000,000.00	60,000,000.00	80,000,000.00
Field Oil Variable Opex	60,000,000.00	90,000,000.00	120,000,000.00
Storage & Loading Facilities Opex	100,000,000.00	150,000,000.00	200,000,000.00
Well Operating Costs Fixed ($2,000/month)	230,400,000.00	230,400,000.00	230,400,000.00
Field Gas Fixed Cost	15,000,000.00	22,500,000.00	30,000,000.00
Field Gas Variable Cost	25,000,000.00	37,500,000.00	50,000,000.00
Electricity Distribution	25,000,000.00	25,000,000.00	25,000,000.00
Field Abandonment	48,000,000.00	48,000,000.00	48,000,000.00
Water Handling			
Transportation of Water for Hydraulic Fracturing Fluid (CDN $)	22,860,000.00	22,860,000.00	22,860,000.00
Wastewater Transport to Injection Site (CDN $)	59,916,000.00	83,016,000.00	106,116,000.00
Deep-well injection cost (CDN $)	49,930,000.00	69,180,000.00	88,430,000.00
Flowback & Produced Water Transport – with Deep Well (DW-Inj)	0.00	0.00	0.00
Flowback & Produced Water Transport – without Deep Well (DW-Inj)	2,496,500,002.00	3,459,000,004.00	4,421,500,005.00
Flowback & Produced Water Treatment – with Deep Well (DW-Inj)	0.00	0.00	0.00
Flowback & Produced Water Treatment – without Deep Well (DW-Inj)	299,580,000.00	415,080,000.00	530,580,001.00
Total Water Handling Costs – with Deep Well (DW-Inj)	132,706,000.00	175,056,000.00	217,406,000.00
Total Water Handling Costs – with Off-Site Transport & Treatment (OSTT)	2,818,940,002.00	3,896,940,004.00	4,974,940,006.00
Total OpEx – with Deep Well (DW-Inj)	**676,106,000.00**	**838,456,000.00**	**1,000,806,000.00**
Total OpEx – with Off-Site Transport & Treatment (OSTT)	**3,362,340,002.00**	**4,560,340,004.00**	**5,758,340,006.00**

Well completions are estimated to use 4 million US gallons of water per well, with 50% water flow-back. The fracking operation will also need an assumed 5,000 US short tons of proppant per well.[28]

The cost of transportation of water for use in formulating hydraulic fracturing fluid is estimated to be $0.50/bbl. In the absence of deep well injection disposal, the costs of flow-back and produced water transport and treatment are: $25.00/bbl for flow-back & produced water transportation, and $3.00/bbl for flow-back and produced water treatment.[29]

Well Abandonment cost is placed at $100,000/well.[30]

Marine dock, oil storage, and loading terminal cost are based on reported costs for the 2 million bbl Melons Island Oil Terminal (MOTI) facility built in 2009, and the NL Whiffen Head Transshipment Terminal built in 1998.

2d. Prices

The inflation-adjusted or real-dollar base case price is assumed to be USD $85/bbl based on a Brent reference. With a USD/CND exchange rate at 0.90, this equates to a sales price of CND $94.44/bbl. Transportation costs at $2.00/bbl yields a field netback price of CND $92.44/bbl.[31] Additional analysis was undertaken for Brent-reference prices of USD $50/bbl and $100/bbl.

While hydrocarbon analysis indicates light oil/condensate with an API density of approximately 50 degrees, not enough information is known at this time to make specific price adjustments for crude quality.

2e. Fiscal Terms

Newfoundland and Labrador has separate fiscal terms for onshore and offshore. Exploration licenses (EL's) 1070 and 1120 are issued by the Canada Newfoundland & Labrador Offshore Petroleum Board (CNLOPB). Therefore the offshore generic fiscal terms are assumed to apply. The details of the generic fiscal regime are provided in Table 2e.1 and Annex 3.

The fiscal terms require estimation of the Government of Canada 10-year bond rate. Analysis assumes this rate to be inflation plus two percentage points; i.e., 4%.[32] This results in nominal-dollar threshold return allowance rates of 9% and 19%, respectively, for the Tier 1 and Tier 2 returns.

It is assumed that Nalcor will participate for 10%, on a full working interest basis.[33]

The potential local or regional fiscal share option at 1%-3% is not an additional levy, rather it is a share of the Provincial gross royalties.

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[28] USGS – Water Used for Hydraulic Fracturing: www.usgs.gov/newsroom/article.asp?ID=4262#.Vd8EsEK3C5w and Estimates of Hydraulic Fracturing (Frac) Sand Production, Consumption, and Reserves in the United States: http://www.rockproducts.com/frac-sand/14403-estimates-of-hydraulic-fracturing-frac-sand-production-consumption-and-reserves-in-the-united-states.html#.VfGwlRFVhBd

[29] Estimates of Hydraulic Fracturing (Frac) Sand Production, Consumption, and Reserves in the United States: www.rockproducts.com/frac-sand/14403-estimates-of-hydraulic-fracturing-frac-sand-production-consumption-and-reserves-in-the-united-states.html#.VfGwlRFVhBd; SPE: "Development and Use of High-TDS Recycled Produced Water for Crosslinked-Gel-Based Hydraulic Fracturing" 2013: www.onepetro.org/conference-paper/SPE-163824-MS and Alberta Oil Magazine. "Railcars and trucks make a comeback as methods for shipping oil" www.albertaoilmagazine.com/2013/02/railcars-trucks-make-oil-comeback/

[30] New Brunswick Onshore Oil and Natural Gas Well Abandonment Study: www.pr-ac.ca/files/files/WellAbandonment_RPT_02Nov04.pdf

[31] The cost of transportation is based on the experience in offshore Newfoundland and Labrador.

[32] The rate of inflation assumed for this analysis is 2% per annum.

[33] This is a simplifying assumption for this analysis. While Nalcor has not yet made a decision to participate; if it does elect to participate it will reimburse the other participants for past costs.

The potential environmental impact fee sensitivity is modeled as an additional fiscal levy for this option.

Table 2e.1. Fiscal terms summary: generic rate of return system.

Newfoundland & Labrador Generic Offshore Fiscal Terms	
Corporate Income Tax	Rate at 29% - 15% Federal and 14% Provincial.
Royalty	Royalty rate sliding scale: 1% - 7.5%. Escalation is based on the level of production and simple payout (recovery of uplifted capital, operating, and exploration costs). The rate slides as follows: before simple payout: 1% before the earlier of: (a) 50 million barrels and (b) 20% of initial established reserves; then 2.5% until 100 million barrels; 5% for the next 100 million barrels; and 7.5% thereafter; after simple payout: 5% for the next 100 million barrels and 7.5% thereafter.
Profit Share	Tier-1 20% after payout (recovery of previous royalty paid and uplifted capital and operating costs, plus a ROR allowance of 5% plus the long term government bond rate); and Tier-2 30% after a ROR allowance of 15% plus the long term bond rate. In determining payout, capital, operating, and pre-development costs can be uplifted by 1%, 10%, and 5%, respectively. Pre-development costs are indexed for inflation for the previous 5 years.
NOTES:	Equity Participation - Newfoundland & Labrador's Energy Plan - 2007 states its policy to obtain a 10% equity position in future oil and gas projects, including compensation, where relevant, for past exploration costs. Equity participation would be via the Newfoundland and Labrador Corporation (Nalcor). Nalcor would be subject to royalty and profit share, but not to corpoate income tax.
	Super Royalty - Not Modeled. An incremental 'Super Royalty' applies to some projects; e.g., White Rose Satellites and Hebron. These projects are liable for an additional 6.50% to the Tier-1 Royalty rate for prices in excess of USD $50 per barrel. The Maximum net royalty rate can thus be 36.5% after Tier 2 payout. An incremental royalty rate also applies to Hibernia extension projects.
	See Annex 3 for additional details
Rodgers Oil & Gas Consulting	

On November 2nd the Government announced new generic offshore fiscal terms. At time of writing it is unclear how these terms will affect this Green Point Shale prospect. While analysis scope could not anticipate these new terms, a preliminary indication of the potential impacts on project economics is included in Annex 6. The R-Factor fiscal terms are described in Annex 3.

3 ANALYSIS APPROACH

3a. Nominal vs. Real Analysis

All model calculations are first performed in nominal dollars. Real dollar results are calculated by then removing the inflation component from the nominal results. Unless otherwise indicated, all results are presented in real-dollar terms. Price and cost escalation are assumed to equal inflation at 2% per annum. All calculations are also based on mid-year escalation and discounting.[34]

3b. Treatment of Nalcor

It is the private company (Shoal Point Energy – SPE) that will determine whether this project proceeds to development and production. Therefore, and to reduce analysis complexity at this early stage in the project, Nalcor is assumed to be fully taxable. When combined with the other simplifying assumption – that Nalcor has participated on a full working interest basis, this means that the rate of return reported for this analysis will be the same for the project, overall, and for both the private company (SPE) and the state company (Nalcor). The effect of Nalcor being exempt from CIT – both Federal and Provincial – is to increase the ROR for both the project and Nalcor. Inclusion of Nalcor on a fully taxable and working interest basis means that SPE's ROR would remain unchanged.

3c. Scenarios and Sensitivities

The cash flow model used to support the analysis for this report is proprietary to Rodgers Oil & Gas Consulting. Referred to as PEET – Petroleum Economics Evaluation Tool – this model is specifically designed to perform oil and gas economics evaluation and fiscal systems comparison. While PEET permits the full scope of benefit-cost analysis, this report is restricted to project cash flow analysis. Annex 2 provides further description.

Two broad scenarios are assessed – waste water disposal via (1) deep well injection (DW-Inj) and (2) off-site transport and treatment (OSTT). Special emphasis on waste water disposal is made because waste water disposal is one of the most serious concerns with unconventional oil and gas developments, and the associated costs can vary dramatically if deep well injection cannot be used.

The basic approach is to present and discuss the traditional economic criteria used to facilitate project economics decision-making, primarily the rate of return and the net present value criteria.

In addition to the two waste water disposal scenarios, sensitivity analysis is conducted with respect to drilling costs, United States – Canada currency exchange rate, investor discount rate, a potential additional up-front cost for new road construction, and a potential new fiscal levy to reflect environmental risk and excessive demands on local infrastructure. **A general sensitivity analysis is also conducted, with plus-minus 45% changes, at increments of 15 percentage points, separately for price, recoverable reserves, CapEx, and OpEx.**

A limited expected monetary value risk analysis is also included.

Annotated tables presenting model output results are included to assist with understanding selected key fiscal calculations related to the determination of the province's gross royalty and profit share, and the corporate income tax.

[34] Mid-year escalation means that a current year price or cost is escalated at one-half of the escalation rate. Similarly, Discounting is performed to the mid-point of the first cash flow year. This is a common approach, although standard Excel calculations assume no escalation or discounting for the first year.

4 ANALYSIS RESULTS

4a. Project Cash Flow and Costs

This section begins with the presentation of the project-level real-dollar net cash flows for the 150 MM bbls reserves case under the USD $85/bbl price scenario for each waste water disposal option – Deep Well (DW-Inj) and Off-Site Transport & Treatment (OSTT).

These two cases are first presented with accompanying cash flow charts (Figures 4a.1 and 4a.2) to help illustrate the cash flow differences between the waste water disposal options. These charts also illustrate the relationship among the various cash flow components – revenue, CapEx, OpEx, payments to governments, and project net cash flow.

These cash flows are subject to an economic limit test – referred to as the marginal revenue over marginal cost cutoff. This means that, depending on the economics of the scenario, the cash flows may be shorter than the original and, therefore, the recoverable reserves for that case may similarly be less than the original. For example, the cash flow for the 150 MM bbls case at USD $85/bbl with the higher-cost OSTT waste water disposal option is cut of 8 years early in 2032. Due to the hyperbolic decline of the production profile this results only in the loss of 0.650 MM bbls, reducing the recovered reserves in this case from 150 to 149.350 MM bbls.

Explanation of the charts: The dark blue bars illustrate the netback sales revenue. CapEx and OpEx are respectively shown with the light blue and red bars. Project financing is not incorporated for this analysis – all costs are assumed to be financed from equity. Producer payments to governments is shown by the green bars. The dashed black line represents producer net cash flow, peaking at approximately $1 billion (for the OSTT case) in the 6th year of production. The cumulative net cash flow – the solid black line – is measured on the secondary axis.

The most striking difference between the two charts can be seen by comparing the OpEx (red bars). This results from the higher costs for the OSTT option. Another immediate difference is the much reduced cumulative NCF for the OSTT option. Cumulative NCF is correspondingly reduced from just over $5,000 MM to about $3,250 MM. Further discussion is provided below.

Tables 4a.1 and 4a.2 present the annual cash flows used in the charts. Comparing the total net cash flow for each option shows the impact of off-site waste water disposal, reducing the project NCF from $5,148.6 MM to $3,246.1 MM.

Notice that OpEx, in the OSTT is $4,914.8 MM, compared to $846.1 in the DW-Inj case. The reason why NCF is only reduced by $1,901.9 MM, and not by the full amount of the OpEx cost increase, has to do with the deductibility of OpEx in determining the corporate income tax and profit share payments to governments. OpEx is also an allowed cost in determining payout for both gross royalty and profit share.

Notice also that government revenue is decreased by $2,128.3 MM ($5,068.648-$2,940.386). When this difference is added to the NCF difference, the combined result totals $4,030.2 MM, still not fully equal to $4,068.7 MM in extra cost for the OSTT. The remaining difference ($38.5 MM) is attributed to offsetting lower CapEx ($62.8 MM) in the OSTT option with the impact of the field being cut off one year earlier ($24.3 MM).

The economic results for the DW-Inj base cases assessed are compared in Table 4a.3. This table provides the net cash flow, net present value, and internal rate of return (IRR) for the overall project, as well as for the private operator (Shoal Point Energy) and Nalcor.

Government revenues are also recorded for each fiscal instrument – corporate income tax (Federal and Provincial),

royalty, and profit share. The government share is also presented with and without the NCF share to Nalcor.[35]

Table 4a.3 shows that the DW-Inj option records positive NPVs above the breakeven 10% rate of return (ROR or IRR) level for all cases except the low $50/bbl price with the low 100 MM bbls reserves. Excluding this case, the remaining cases show an IRR range from 17.65% to 86.03%.

The results for Shoal Point Energy and Nalcor reflect their respective 90/10 shares of the project as modeled.

Discussion of Government Revenue Results: Government revenue estimates are provided for both levels of government (Federal and Provincial) and delineated by fiscal instrument – corporate income tax, royalty, and profit share. Also delineated are the magnitudes of a scenario where 1% to 3% of Provincial government royalties are allocated to local governments to facilitate local resource management and to offset potential negative externalities such as wear and tear on local infrastructure.

For the DW-Inj case, total direct government revenue (Federal and Provincial without the Nalcor share) is estimated to range from $1,562 MM for the 150 MM bbl – $50/bbl price case to $8,435 MM for the 200 MM bbl – $100/bbl price case. This range excludes the 100 MM bbl – $50/bbl case based on sub-breakeven economics. The Province's share ranges from $1,163 MM to $6,623 MM. When the Nalcor NCF share is added, the Province's share increases to $1,327 MM to $7,458 MM.

The magnitude of the modeled local share transferred as a percent of Provincial gross royalties is shown to range from $1.35 MM to $38.66 MM, depending on the scenario.

Discussion of the economic results for the OSTT waste water disposal option is contained in section 4b below.

[35] There is some debate in the literature regarding whether equity participation shares should be included in the government share. The argument for excluding the equity share expresses the view that this share results not from a right of ownership but as a return on investment. The argument for inclusion is based on government's ultimate control of the state corporation. Another position is that only the share of state company NCF above that required to provide a minimum rate of return should be included, and then only the portion equivalent to the government share without inclusion. For this analysis, the common approach is followed to include the full NCF to Nalcor.

Figure 4a.1. Illustration of project cash flows – DW-Inj.

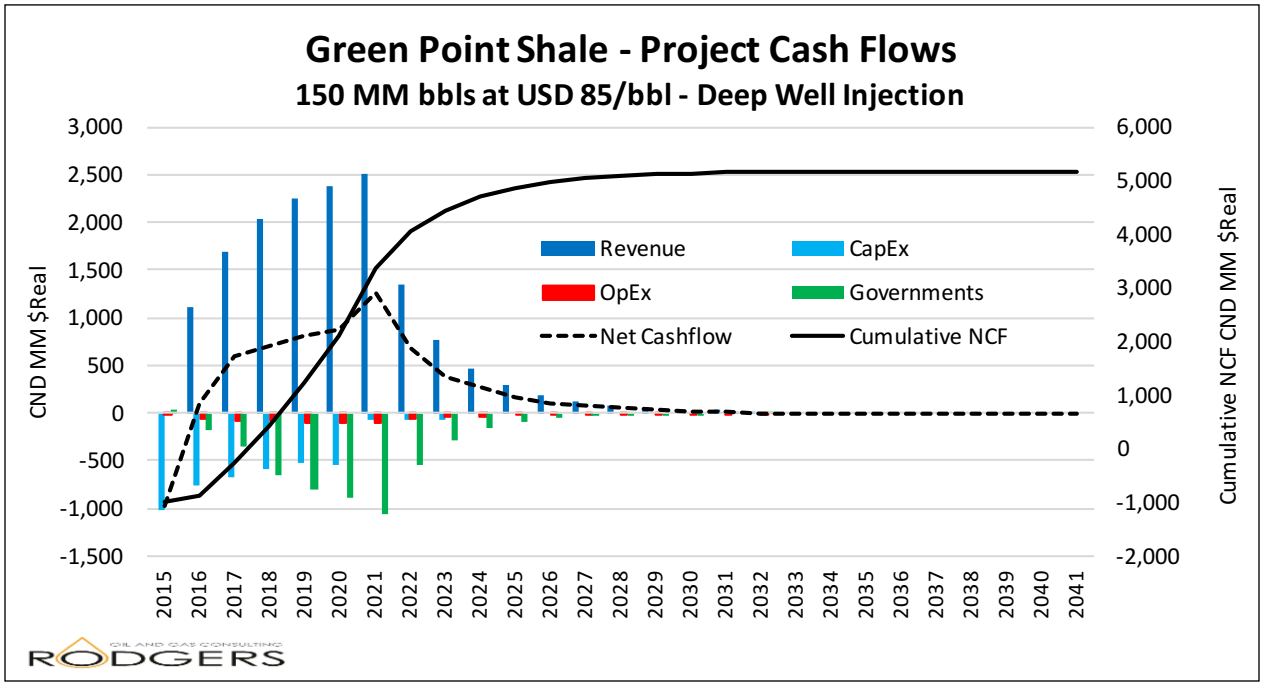

Figure 4a.2. Illustration of project cash flows – OSTT.

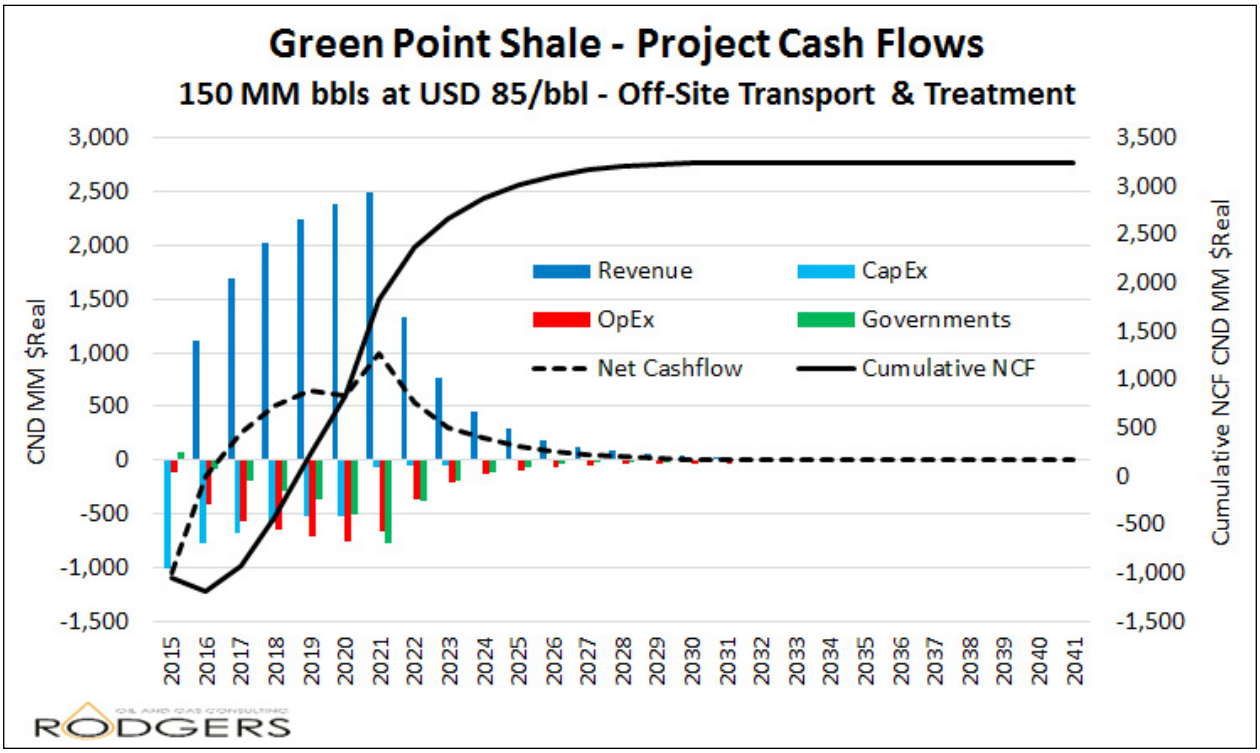

Table 4a.1. Project cash flows – DW-Inj, $85/bbl.

Shoal Point Energy - Green Point Shale - USD 85							
Net Cash Flow (Project)							
Canada		Nfld.&Lab.			Offshore		
	Fiscal System:	CAN.NL-Generic Offshore ROR-NoSR			Oil	$ Nominal	(CND MM)
150 MM bbl DW-Inj							
(CND MM)							
	NetBack Revenue	Capital CapEx	Operating OpEx	Operating Income	Financial Community	Governments	**Net Net Cashflow**
2015	0.000	-1,009.950	-8.081	-1,018.031	0.000	45.105	-972.926
2016	1,113.062	-768.212	-50.618	294.232	0.000	-186.865	107.367
2017	1,693.910	-676.399	-73.275	944.235	0.000	-342.700	601.535
2018	2,028.659	-597.005	-87.370	1,344.284	0.000	-644.638	699.646
2019	2,240.950	-528.382	-97.250	1,615.318	0.000	-808.472	806.846
2020	2,388.621	-534.293	-104.950	1,749.378	0.000	-877.167	872.211
2021	2,500.566	-74.758	-102.388	2,323.421	0.000	-1,069.454	1,253.967
2022	1,338.556	-62.994	-61.848	1,213.713	0.000	-537.066	676.648
2023	763.888	-64.254	-41.952	657.682	0.000	-277.336	380.346
2024	459.230	0.000	-31.549	427.680	0.000	-164.697	262.983
2025	288.263	0.000	-25.850	262.413	0.000	-94.816	167.597
2026	187.661	0.000	-22.630	165.031	0.000	-55.540	109.491
2027	126.037	0.000	-20.785	105.252	0.000	-32.595	72.657
2028	86.966	0.000	-19.739	67.226	0.000	-18.703	48.524
2029	61.440	0.000	-24.507	36.934	0.000	-7.202	29.731
2030	44.321	0.000	-24.352	19.969	0.000	-1.501	18.468
2031	32.570	0.000	-24.395	8.175	0.000	1.832	10.007
2032	24.335	0.000	-24.571	-0.236	0.000	3.169	2.933
2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2036	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2039	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2040	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2041	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	**15,379.035**	**-4,316.247**	**-846.111**	**10,216.677**	**0.000**	**-5,068.648**	**5,148.029**
5%	*11,881.858*	*-3,774.965*	*-611.581*	*7,495.312*	*0.000*	*-3,852.337*	*3,642.975*
10%	*9,420.376*	*-3,349.530*	*-464.396*	*5,606.450*	*0.000*	*-2,994.571*	*2,611.878*
15%	*7,632.665*	*-3,008.918*	*-366.124*	*4,257.624*	*0.000*	*-2,373.865*	*1,883.759*
20%	*6,299.508*	*-2,731.704*	*-297.158*	*3,270.646*	*0.000*	*-1,914.409*	*1,356.237*
Rodgers Oil & Gas Consulting							

Table 4a.2. Project cash flows – OSTT, $85/bbl.

Shoal Point Energy - Green Point Shale - USD 85							
Net Cash Flow (Project)							
Canada		Nfld.&Lab.			Offshore		
	Fiscal System:	CAN.NL-Generic Offshore ROR-NoSR			Oil	$ Nominal	(CND MM)
150 MM bbl OSTT							
(CND MM)							
	NetBack Revenue	Capital CapEx	Operating OpEx	Operating Income	Financial Community	Governments	**Net Net Cashflow**
2015	0.000	-1,009.950	-111.589	-1,121.540	0.000	75.122	-1,046.418
2016	1,113.062	-768.212	-405.590	-60.740	0.000	-83.924	-144.663
2017	1,693.910	-676.399	-560.503	457.007	0.000	-193.386	263.621
2018	2,028.659	-587.038	-651.756	789.866	0.000	-281.756	508.110
2019	2,240.950	-518.215	-711.399	1,011.337	0.000	-363.792	647.545
2020	2,388.621	-523.923	-754.427	1,110.272	0.000	-504.132	606.140
2021	2,500.566	-64.180	-662.664	1,773.722	0.000	-780.119	993.602
2022	1,338.556	-52.205	-361.765	924.586	0.000	-384.547	540.039
2023	763.888	-53.249	-213.109	497.530	0.000	-192.582	304.949
2024	459.230	0.000	-134.444	324.786	0.000	-112.657	212.129
2025	288.263	0.000	-90.438	197.825	0.000	-62.345	135.480
2026	187.661	0.000	-64.677	122.984	0.000	-34.513	88.472
2027	126.037	0.000	-49.025	77.013	0.000	-18.534	58.479
2028	86.966	0.000	-39.225	47.741	0.000	-9.032	38.709
2029	61.440	0.000	-38.273	23.168	0.000	-0.384	22.783
2030	44.321	0.000	-34.282	10.039	0.000	2.460	12.498
2031	32.570	0.000	-31.692	0.878	0.000	3.733	4.611
2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2036	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2039	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2040	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2041	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	**15,354.700**	**-4,253.372**	**-4,914.857**	**6,186.472**	**0.000**	**-2,940.386**	**3,246.086**
5%	*11,871.496*	*-3,728.015*	*-3,825.452*	*4,318.029*	*0.000*	*-2,192.998*	*2,125.031*
10%	*9,415.785*	*-3,313.763*	*-3,063.834*	*3,038.188*	*0.000*	*-1,671.274*	*1,366.914*
15%	*7,630.557*	*-2,981.177*	*-2,511.833*	*2,137.547*	*0.000*	*-1,297.962*	*839.585*
20%	*6,298.506*	*-2,709.840*	*-2,099.745*	*1,488.922*	*0.000*	*-1,024.889*	*464.033*
Rodgers Oil & Gas Consulting							

Table 4a.3. Economic results – DW-Inj.

Green Point Shale Economic Results Canadian Dollars - Real Values (Millions) Water Disposal - Deep Well Injection (DW-Inj)									
	Recoverable Reserves								
	100 MM bbls			150 MM bbls			200 MM bbls		
United States Dollar Price Per bbl	$50	$85	$100	$50	$85	$100	$50	$85	$100
Canadian Dollar Equivalent Price [1]	$53.56	$92.44	$109.11	$53.56	$92.44	$109.11	$53.56	$92.44	$109.11
Project									
Net Cash Flow (NCF)	322.88	2,303.60	3,099.38	1,632.59	4,473.88	5,713.96	2,823.94	6,688.04	8,339.27
Net Present Value (NPV10)	-413.33	893.77	1,399.55	455.76	2,261.39	3,035.86	1,222.78	3,640.94	4,666.79
Internal Rate of Return (IRR)	3.33%	25.19%	33.81%	17.65%	48.06%	60.56%	30.77%	70.03%	86.03%
Private Investor (Shoal Point Energy)									
Net Cash Flow (NCF)	290.59	2,073.24	2,789.44	1,469.33	4,026.50	5,142.57	2,541.55	6,019.23	7,505.34
Net Present Value (NPV10)	-371.99	804.39	1,259.60	410.19	2,035.25	2,732.27	100.50	3,276.84	4,200.11
Internal Rate of Return (IRR)	3.33%	25.19%	33.81%	17.65%	48.06%	60.56%	30.77%	70.03%	86.03%
State Company (Nalcor)									
Net Cash Flow (NCF)	32.29	230.36	309.94	163.26	447.39	571.40	282.39	668.80	833.93
Net Present Value (NPV10)	-41.33	89.38	139.96	45.58	226.14	303.59	122.28	364.09	466.68
Internal Rate of Return (IRR)	3.33%	25.19%	33.81%	17.65%	48.06%	60.56%	30.77%	70.03%	86.03%
Government Revenue (Undiscounted)									
Total Government (Federal & Provincial)									
With Nalcor NCF	407.82	2,488.88	3,428.53	1,725.33	4,975.95	6,352.21	3,157.61	7,428.89	9,268.97
Without Nalcor NCF	375.53	2,258.52	3,118.59	1,562.07	4,528.56	5,780.81	2,875.22	6,760.09	8,435.04
Provincial Government Total									
With Nalcor NCF	283.15	1,948.87	2,722.67	1,327.09	3,979.70	5,093.97	2,507.67	5,966.50	7,457.73
Without Nalcor NCF	250.86	1,718.51	2,412.73	1,163.83	3,532.31	4,522.57	2,225.28	5,297.70	6,623.80
Direct									
Federal (CIT)	124.67	540.01	705.86	398.24	996.25	1,258.24	649.94	1,462.39	1,811.24
Provincial (CIT)	116.35	504.00	658.81	371.70	929.84	1,174.36	606.61	1,364.89	1,690.49
Subtotal - Total CIT	241.02	1,044.01	1,364.67	769.94	1,926.09	2,432.60	1,256.55	2,827.28	3,501.73
Royalty	134.51	339.83	434.30	352.91	711.23	864.83	568.50	1,070.24	1,288.57
Profit Share	0.00	874.68	1,319.62	439.22	1,891.24	2,483.38	1,050.17	2,862.57	3,644.74
Subtotal - Total Province	250.86	1,718.51	2,412.73	1,163.83	3,532.31	4,522.57	2,225.28	5,297.70	6,623.80
Local Share [2]									
at 1% of Royalty	1.35	3.40	4.34	3.53	7.11	8.65	5.69	10.70	12.89
at 2% of Royalty	2.69	6.80	8.69	7.06	14.22	17.30	11.37	21.40	25.77
at 3% of Royalty	4.04	10.19	13.03	10.59	21.34	25.94	17.06	32.11	38.66
Equity Participation (Nalcor 10%)[3]									
Net Cash Flow (NCF)	32.29	230.36	309.94	163.26	447.39	571.40	282.39	668.80	833.93

1. Based on a Canadian-United States dollar (CND-USD) exchange rate of 0.90 and transportation costs of CND $2.00 per bbl; e.g., USD $85/0.90 - CND $2.00 = CND $92.44
2. Local includes only the modeled share of Provincial government royalties; it is a subset of the Provincial share; it does not include indirect taxes such as property tax.
3. Analysis assumes Nalcor to be fully taxable and modeled as a 10% full working interest partner.

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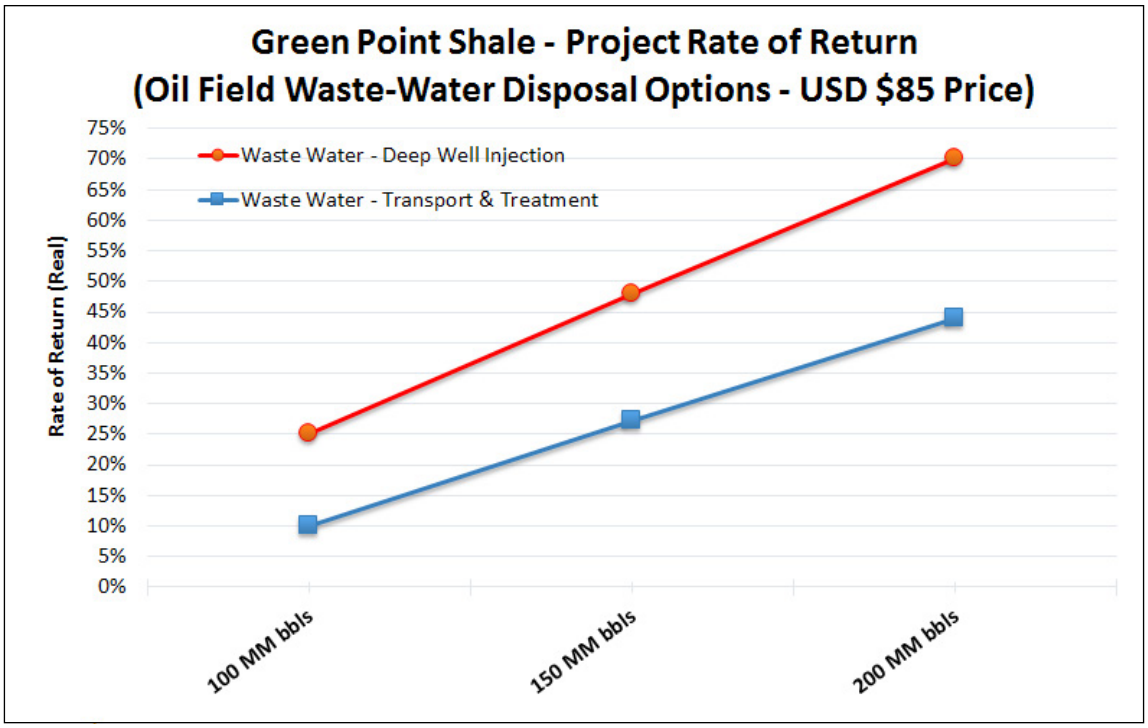
4b. Waste Water Disposal

Safe disposal of waste water fluids from the drilling and fracking operations is a necessity. The least expensive option is to reinject these fluids deep underground – well below, and sealed from, any contact with the fresh water aquifer. This is referred to here as the deep well injection option (DW-Inj). If this option is not possible, these fluids would then have to be transported from the Province to be treated before disposal. This option is the off-site transport and treatment option (OSTT). Due primarily to transportation costs, the OSTT disposal option is significantly more expensive, as already highlighted.

Discussion of Project Economics Results: The much higher costs associated with waste water disposal if the deep well injection option cannot be used causes a substantial reduction in the project's economic prospects. Figure 4b.1 shows the producer rate of return at the $85/bbl price scenario for the three reserve sizes modeled under the two waste water disposal options – (1) deep well injection (red line) and (2) transport to an off-site treatment facility (blue line).

Figure 4b.1. Rate of return comparison – waste water disposal – USD $85 price.



All cases under the $85/bbl price depicted in Figure 4b.1 are economically viable, with the economics of the low 100 MM bbls OSTT disposal option marginal, as measured by a 10% real (approximate 12% nominal) producer rate of return. The rate of return range across both waste water disposal options is a low of 10% to a maximum 70%. For the 150 MM bbls case, the ROR range is an attractive 27%-48%, depending on the waste water disposal option.

Table 4b.1 presents the economic results for all OSTT cases. These results can be compared to those for the DW-Inj cases in Table 4a.3 above.

For the OSTT waste water disposal option, Table 4b.1 shows all $50/bbl price cases to be uneconomic – see red text in the table.

In addition, and as already observed, the low reserves 100 MM bbls case with an IRR of 10.11% is seen as marginal at the USD $85/bbl price scenario. This suggests that, with current expectations for future oil prices, the OSTT option is likely to be uneconomic unless recoverable reserves are greater than 100 MM bbls and price is in the order of USD $85/bbl. Additional discussion of pricing is contained in the sensitivity analysis section below.

Discussion of Government Revenue Results: Due to the significantly higher cost associated with the OSTT case, the government share is also substantially reduced from that under the lower cost DW-Inj option. For example, the Provincial government share range for the $85/bbl price scenario, without the Nalcor NCF, is $592 MM to $3,297 MM, compared to a range of $1,719 MM to $5,298 MM for the DW-Inj case.

Of course, the 200 MM bbls case with $100/bbl would record much higher government revenues; for example, a combined government share of $6,593 MM for the OSTT case with Nalco's share. The comparable value for the DW-Inj case is $9,268 MM.

Table 4b.1. Economic results – OSTT.

Green Point Shale Economic Results Canadian Dollars - Real Values (Millions) Water Disposal - Off-Site Transport & Treatment									
	Recoverable Reserves								
	100 MM bbls			150 MM bbls			200 MM bbls		
United States Dollar Price Per bbl	$50	$85	$100	$50	$85	$100	$50	$85	$100
Canadian Dollar Equivalent Price [1]	$53.56	$92.44	$109.11	$53.56	$92.44	$109.11	$53.56	$92.44	$109.11
Project									
Net Cash Flow (NCF)	-1,515.06	1,072.26	1,867.64	-567.52	2,742.33	3,981.26	355.05	4,468.19	6,098.78
Net Present Value (NPV10)	-1,620.48	7.36	546.18	-1,023.97	1,112.02	1,900.68	-441.65	2,205.60	3,225.60
Internal Rate of Return (IRR)	-14.93%	10.11%	18.35%	-5.49%	27.16%	39.44%	3.39%	44.00%	59.40%
Private Investor (Shoal Point Energy)									
Net Cash Flow (NCF)	-1,363.55	965.04	1,680.88	-510.77	2,468.09	3,583.13	319.55	4,021.37	5,488.90
Net Present Value (NPV10)	-1,458.43	6.63	491.56	-921.57	1,000.82	1,710.61	-397.49	1,985.04	2,903.04
Internal Rate of Return (IRR)	-14.93%	10.11%	18.35%	-5.49%	27.16%	39.44%	3.39%	44.00%	59.40%
State Company (Nalcor)									
Net Cash Flow (NCF)	-151.51	107.23	186.76	-56.75	274.23	398.13	35.51	446.82	609.88
Net Present Value (NPV10)	-162.05	0.74	54.62	-102.40	111.20	190.07	-44.17	220.56	322.56
Internal Rate of Return (IRR)	-14.93%	10.11%	18.35%	-5.49%	27.16%	39.44%	3.39%	44.00%	59.40%
Government Revenue (Undiscounted)									
Total Government (Federal & Provincial)									
With Nalcor NCF	-546.19	980.80	1,919.26	53.05	2,881.88	4,255.16	702.55	4,738.13	6,592.65
Without Nalcor NCF	-394.68	873.57	1,732.50	109.80	2,607.65	3,857.03	667.04	4,291.31	5,982.77
Provincial Government Total									
With Nalcor NCF	-285.69	698.82	1,472.25	117.51	2,250.08	3,363.80	572.10	3,743.89	5,255.51
Without Nalcor NCF	-134.18	591.59	1,285.49	174.26	1,975.85	2,965.67	536.59	3,297.07	4,645.63
Direct									
Federal (CIT)	-260.50	281.98	447.01	-64.46	631.80	891.36	130.45	994.24	1,337.14
Provincial (CIT)	-243.13	263.18	417.21	-60.16	589.68	831.94	121.76	927.95	1,248.00
Subtotal - Total CIT	-503.63	545.16	864.22	-124.62	1,221.48	1,723.30	252.21	1,922.19	2,585.14
Royalty	108.95	256.76	360.62	234.42	643.33	808.16	414.83	1,014.56	1,232.55
Profit Share	0.00	71.65	507.66	0.00	742.84	1,325.57	0.00	1,354.56	2,165.08
Subtotal - Total Province	-134.18	591.59	1,285.49	174.26	1,975.85	2,965.67	536.59	3,297.07	4,645.63
Local Share [2]									
at 1% of Royalty	1.09	2.57	3.61	2.34	6.43	8.08	4.15	10.15	12.33
at 2% of Royalty	2.18	5.14	7.21	4.69	12.87	16.16	8.30	20.29	24.65
at 3% of Royalty	3.27	7.70	10.82	7.03	19.30	24.24	12.44	30.44	36.98
Equity Participation (Nalcor 10%)[3]									
Net Cash Flow (NCF)	-151.51	107.23	186.76	-56.75	274.23	398.13	35.51	446.82	609.88

1. Based on a Canadian-United States dollar (CND-USD) exchange rate of 0.90 and transportation costs of CND $2.00 per bbl; e.g., USD $85/0.90 - CND $2.00 = CND $92.44
2. Local includes only the modeled share of Provincial government royalties; it is a subset of the Provincial share; it does not include indirect taxes such as property tax.
3. Analysis assumes Nalcor to be fully taxable and modeled as a 10% full working interest partner.

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4c. Well Cost Sensitivity

Table 4c.1 shows, for the USD $85/bbl price case, the impact on investor economics from a 25% reduction in well drilling and completion (D&C) costs and a 50% increase in these costs. Results are shown for the project internal rate of return and net present value. The associated revenue ($real, undiscounted) to governments is also shown.[36]

The table results show that all but one case (100 MM bbls with OSTT) would be economically viable at a price of $85/bbl, even if D&C costs were to be 50% higher than those of the base case.

Table 4c.1. Impact of well costs: USD $85/bbl.

Green Point Shale - Well Cost Sensitivity ($Real, USD $85 Price)						
Project Internal Rate of Return						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	37.7%	65.6%	92.5%	18.1%	39.1%	59.1%
Base Case ($10 MM)	25.2%	48.1%	70.0%	10.1%	27.2%	44.0%
Cost Increase by 50%	11.2%	27.5%	43.7%	-0.5%	13.4%	25.3%
Project Net Present Value (NPV10) - CND $Million						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	1,279.46	2,646.03	4,016.85	426.31	1,508.41	2,579.60
Base Case ($10 MM)	893.77	2,261.39	3,640.94	7.36	1,112.02	2,205.60
Cost Increase by 50%	108.39	1,480.92	2,860.66	-1,002.43	322.98	1,392.91
Government Revenue (Undiscounted) - CND $Million						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	2,716.68	4,967.08	7,206.03	1,318.52	3,039.97	4,738.87
Base Case ($10 MM)	2,258.52	4,528.56	6,760.09	873.57	2,807.65	4,291.31
Cost Increase by 50%	1,271.34	3,630.83	5,894.02	312.76	16+50.02	3,458.06
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However, if price were to be $50/bbl, as shown in Table 4c.2, the economics would be much different. In this case, even the base cases are shown to be mostly uneconomic, as seen by negative values for the NPV and IRR. Only the DW-Inj 150 MM bbls and 200 MM bbls cases show positive economics in excess of the minimum required.

When D&C costs are increased by 50%, only the high reserves-low overall cost case (DW-Inj 200 MM bbls) passes the economic test, with a positive NPV of 424.59.

These results improve if D&C costs can be reduced by 25%. In this scenario all of the DW-Inj cases are economic. The OSTT 200 MM bbls case would also be economic if D&C costs were decreased by 25%.

At the $100 price level all but one case would be economically viable – the low 100 MM bbls with OSTT and D&C costs that are 50% higher would still be uneconomic.

[36] Note that government revenue results reported are meaningless for those case where the project NPV10 is less than the zero breakeven level. For example, Table 4c.3 records government revenue for the 100 MM bbls – OSTT – $100 price scenario with a 50% increase in D&C costs to be $872.52 MM. However, based on the negative NPV10 value of $-308.84 MM, this project would not be developed.

Table 4c.2. Impact of well costs: USD $50/bbl.

Green Point Shale - Well Cost Sensitivity ($Real, USD $50 Price)						
Project Internal Rate of Return						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	11.6%	28.4%	44.9%	-11.0%	0.6%	11.2%
Base Case ($10 MM)	3.3%	17.7%	30.8%	-14.9%	-5.5%	3.4%
Cost Increase by 50%	-6.6%	5.1%	14.9%	-19.2%	-12.4%	-5.8%
Project Net Present Value (NPV10) - CND $Million						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	74.62	845.74	1,627.11	-1,094.65	-500.19	66.64
Base Case ($10 MM)	-413.33	455.76	1,222.78	-1,620.48	-1,023.97	-441.65
Cost Increase by 50%	-1,469.28	-434.73	424.59	-2,671.99	-2,075.13	-1,481.98
Government Revenue (Undiscounted) - CND $Million						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	704.21	2,037.09	3,297.42	-165.46	360.79	931.98
Base Case ($10 MM)	375.53	1,562.07	2,875.22	-394.68	118.80	667.04
Cost Increase by 50%	-110.47	742.97	1,955.12	-863.66	-341.86	172.71
Rodgers Oil & Gas Consulting						

Table 4c.3. Impact of well costs: USD $100/bbl.

Green Point Shale - Well Cost Sensitivity ($Real, USD $100 Price)						
Project Internal Rate of Return						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	48.3%	81.1%	112.8%	28.6%	53.7%	78.1%
Base Case ($10 MM)	33.8%	60.6%	86.0%	18.4%	39.4%	59.4%
Cost Increase by 50%	17.1%	36.8%	55.6%	6.8%	22.2%	37.0%
Project Net Present Value (NPV10) - CND $Million						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	1,784.62	3,424.90	5,051.18	959.37	2,284.46	3,624.29
Base Case ($10 MM)	1,399.55	3,035.86	4,666.79	546.18	1,900.68	3,225.60
Cost Increase by 50%	612.57	2,260.34	3,892.63	-308.84	1,116.14	2,445.10
Government Revenue (Undiscounted) - CND $Million						
Per Well	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
D&C Costs	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Cost Reduce by 25%	3,568.76	6,209.75	8,869.41	21,857.23	4,291.97	6,388.33
Base Case ($10 MM)	3,118.59	5,780.81	8,435.04	1,732.50	3,857.03	5,982.77
Cost Increase by 50%	2,197.32	4,899.05	7,569.44	872.52	2,965.95	5,128.70
Rodgers Oil & Gas Consulting						

4d. Potential New Infrastructure Investment

Wear and tear on local roadways as a result of heavy traffic associated with drilling and fracking operations may require that these roadways be extensively repaired or even replaced. Table 4d.1 shows for the USD $85/bbl price case, the impact on investor economics from an assumed $100 MM investment by the project investors.

Project NPV's are shown to be marginally reduced as a result of the assumed additional $100 MM investment in the first year of the cash flow before the start of production. For example, the NPV for the 100 MM bbls-DW-Inj case would be reduced by about 6% from $893.77 MM to $840.37 MM. **The 100 MM bbl-OSTT case would be changed from marginal to sub economic – the NPV10 would be reduced from 7.36 MM to a negative 57.86 MM.**

Table 4d.1. Impact of new infrastructure investment: USD $85/bbl.

Green Point Shale - New Infrastructure Investment Sensitivity ($Real, USD $85/bbl Price)						
Project Internal Rate of Return						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	25.2%	48.1%	70.0%	10.1%	27.2%	44.0%
Base Case + $100 MM	23.7%	45.6%	66.8%	9.2%	25.7%	41.8%
Project Net Present Value (NPV10) - CND $Million						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	893.77	2,261.39	3,640.94	7.36	1,112.02	2,205.60
Base Case + $100 MM	840.37	2,215.48	3,605.92	-57.86	1,057.98	2,153.06
Government Revenue (Undiscounted) - CND $Million						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	2,258.52	4,528.56	6,760.09	873.57	2,807.65	4,291.31
Base Case + $100 MM	2,205.70	4,469.91	6,689.62	839.46	2,556.20	4,241.16
Rodgers Oil & Gas Consulting						

Table 4d.2 also records the general expected decrease in NPV as a result of the increased expenditure. At a price of $50/bbls, only the 150 MM bbls and 200 MM bbls cases with the lower cost DW-Inj waste water disposal option would be economically viable. This result is unchanged from the Base Case.

Table 4d.2. Impact of new infrastructure investment: USD $50/bbl.

Green Point Shale - New Infrastructure Investment Sensitivity ($Real, USD $50/bbl Price)						
Project Internal Rate of Return						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	3.3%	17.7%	30.8%	-14.9%	-5.5%	3.4%
Base Case + $100 MM	2.5%	16.4%	29.1%	-15.2%	-6.0%	2.7%
Project Net Present Value (NPV10) - CND $Million						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	-413.33	455.76	1,222.78	-1,620.48	-1,023.97	-441.65
Base Case + $100 MM	-480.06	397.42	1,179.08	-1,688.18	-1,091.66	-507.41
Government Revenue (Undiscounted) - CND $Million						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	375.53	1,562.07	2,875.22	-394.68	118.80	667.04
Base Case + $100 MM	344.55	1,516.44	2,809.58	-423.68	89.80	634.09
Rodgers Oil & Gas Consulting						

Table 4d.3 shows that all cases would be economically viable at a crude oil price of $100/bbl.

Table 4d.3. Impact of new infrastructure investment: USD $100/bbl.

Green Point Shale - New Infrastructure Investment Sensitivity ($Real, USD $100/bbl Price)						
Project Internal Rate of Return						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	33.8%	60.6%	86.0%	18.4%	39.4%	59.4%
Base Case + $100 MM	31.9%	56.7%	81.7%	17.4%	37.4%	56.5%
Project Net Present Value (NPV10) - CND $Million						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	1,399.55	3,035.86	4,666.79	546.18	1,900.68	3,225.60
Base Case + $100 MM	1,349.08	2,975.27	4,624.12	506.96	1,847.15	3,174.22
Government Revenue (Undiscounted) - CND $Million						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	3,118.59	5,780.81	8,435.04	1,732.50	3,857.03	5,982.77
Base Case + $100 MM	3,063.84	5,708.32	8,374.28	1,650.73	3,806.93	5,931.36
Rodgers Oil & Gas Consulting						

4e. Potential Environmental Protection Levy

It is noted above that unconventional oil developments may result in added costs through the generation of potential negative socio-economic externalities. Two such costs are wear and tear on local infrastructure; e.g., roads, and the risk from damage to the environment. A number of jurisdictions recognize such costs through some sort of special levy, alternatively referred to as an oil field clean up charge, a coastal protection fee, or environmental protection fee.[37]

Tables 4e.1-4e.3 provide estimates of the impacts of such a levy on project net present value and net cash flow, and on government revenue. Results are provided for three possible royalty-equivalent rates ranging from 1% to 3% of gross net-back revenue. Impacts are provided for both waste-water disposal options under the three reserves sizes and price scenarios modeled.

Looking at the incremental government revenue for the 1% levy under the 200 MM bbls-DW-Inj-$85/bbl scenario in Table 4e.1 reveals the complex relationship between the gross royalty, the profit share, and the corporate income tax. Because the levy would likely be deductible, increasing the levy decreases the profit share and the CIT; however, the decreased profit share serves to increase the CIT, thus dampening some of the benefit from the profit share decrease. The precise effect of the levy depends on the level of project profitability.

While in most cases an increasing levy rate leads to increased revenue for government, there is one case (200 MM bbls with a 1% levy) where adding the levy actually results in less overall government revenue. This results from the levy being treated as an allowable cost for determining the profit share payout. For the particular cash flows in this case, the added cost from the levy causes payout to be delayed thus causing the profit share to be reduced by more than the 1% levy. This is an unusual situation, but clearly possible. It occurs again in the results for the $100/bbl scenario presented in Table 4e.3.

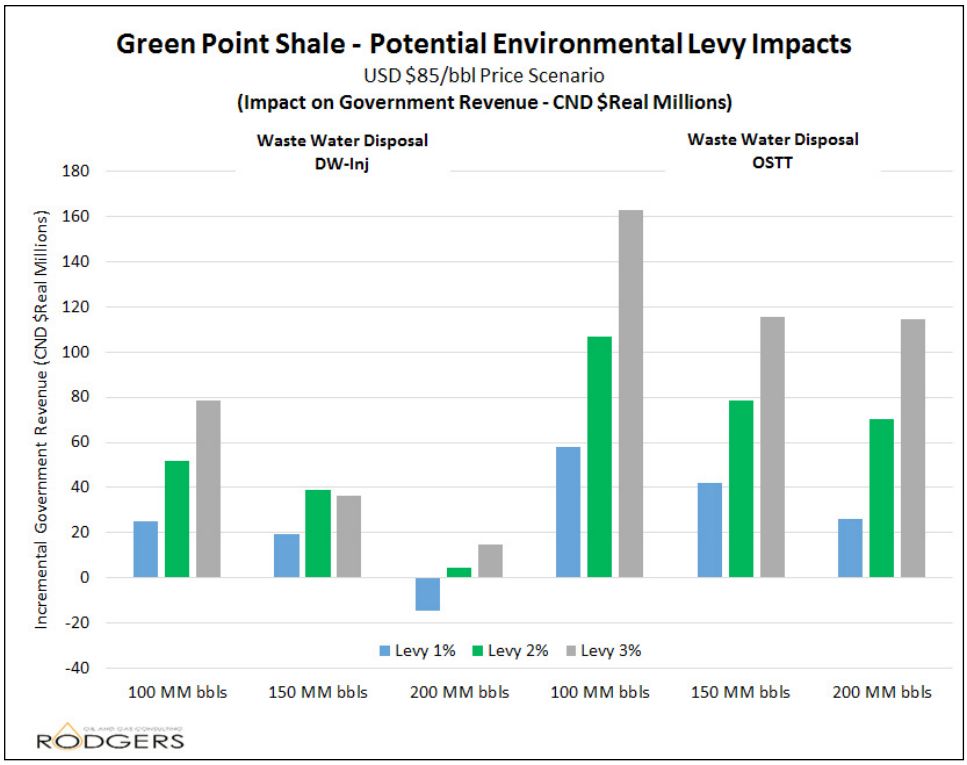
[37] A number of USA jurisdictions impose such levies, though not as onerous as a 1% royalty; e.g., Texas imposes a oil well cleanup fee of $0.00626/bbl and Louisiana imposes a Oil Spill Contingency Fund contribution of $0.02.bbl. Similarly, Ireland imposes approximately USD $110,000 per year to fund the Irish Shelf Petroleum Study Group and a further approximately USD $25,000 per year for the Expanded Offshore Study Group.

Table 4e.1. Impacts of potential environmental levy – $85/bbl.

Green Point Shale - Potential Environmental Levy Impacts [1]						
USD $85/bbl Price Scenario						
(Impact on Project Net Present Value (NPV10) - CND $Real Millions)						
Royalty-Equivalent	Waste Water Disposal with DW-Inj			Waste Water Disposal with OSTT		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	893.77	2261.39	3640.94	7.36	1112.02	2205.60
Levy 1%	874.38	2245.66	3651.63	-30.19	1080.40	2184.26
Levy 2%	854.18	2229.93	3636.17	-63.81	1052.00	2150.42
Levy 3%	833.98	2229.98	3627.26	-100.48	1023.52	2116.54
(Impacts on Project Net Cash Flow - CND $Real Millions)						
Royalty-Equivalent	Waste Water Disposal with DW-Inj			Waste Water Disposal with OSTT		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	2,304	4,474	6,688	1,072	2,742	4,468
Levy 1%	2,278	4,454	6,702	1,014	2,700	4,442
Levy 2%	2,252	4,435	6,684	965	2,664	4,398
Levy 3%	2,225	4,438	6,673	910	2,627	4,354
Incremental Government Revenue from Levy (Undiscounted) - CND $Real Millions						
Royalty-Equivalent	Waste Water Disposal with DW-Inj			Waste Water Disposal with OSTT		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Levy 1%	25.28	19.41	-14.37	57.79	42.05	26.37
Levy 2%	51.82	38.81	4.44	106.76	78.65	70.40
Levy 3%	78.35	36.20	14.95	162.58	115.56	114.50
1. Levy modeled as a royalty on the gross revenue from production.						
Rodgers Oil & Gas Consulting						

Figure 4e.1 illustrates the results for the $85/bbl case of Table 4e.1. The unusual result for the 1% levy under the DW-Inj-200 MM bbls case is evident by the blue bar showing a reduction in government revenue below the zero-value axis.

Figure 4e.1. Impacts of potential environmental levy.



The results of Table 4e.1 also reveal another important aspect of the levy. Indeed of any up-front fixed royalty. The required payment to government would be significantly higher under the less profitable OSTT scenario, thereby further disadvantaging this option. For example, a 2% levy under the DW-Inj-150 MM bbls scenario would require a payment of $38.81 MM; this payment would increase to $78.65 MM for the higher cost OSTT option.

Comparing the incremental government revenue for the $85/bbl price (Table 4e.1) and $50/bbl price (Table 4e.2) scenarios shows the incremental revenue to be greater in the lower price case. The net government revenue of $38.81 MM for the 2% levy under the $85/bbl price case discussed above increases to $66.49 MM under the lower $50/bbl case. This results from the reduced importance of the profit share under lower price conditions, thereby giving the up-front levy more weight, and avoiding potential revenue offsets from the profit share payout effects. Under the $50/bbl price scenario there is less opportunity to see the levy offset by a reduced profit share.

The NPV results in Table 4e.2 again illustrate the general unattractive economics of the OSTT water disposal option at the $50/bbl price level. At this price level the lower 100 MM bbls reserves scenario is also uneconomic.

Table 4e.2. Impacts of potential environmental levy – $50/bbl.

Green Point Shale - Potential Environmental Levy Impacts [1]						
USD $50/bbl Price Scenario						
(Impact on Project Net Present Value (NPV10) - CND $Real Millions)						
Royalty-Equivalent	Waste Water Disposal with DW-Inj			Waste Water Disposal with OSTT		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	-413.33	455.76	1222.78	-1620.48	-1023.97	-441.65
Levy 1%	-436.80	430.30	1214.40	-1643.93	-1059.17	-488.59
Levy 2%	-460.26	408.37	1202.27	-1667.38	-1094.37	-535.52
Levy 3%	-483.73	386.44	1182.66	-1690.82	-1129.57	-582.46
(Impacts on Project Net Cash Flow - CND $Real Millions)						
Royalty-Equivalent	Waste Water Disposal with DW-Inj			Waste Water Disposal with OSTT		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	323	1,633	2,824	-1,515	-568	355
Levy 1%	285	1,596	2,816	-1,553	-624	279
Levy 2%	247	1,566	2,802	-1,590	-681	204
Levy 3%	209	1,536	2,776	-1,628	-738	128
Incremental Government Revenue from Levy (Undiscounted) - CND $Real Millions						
Royalty-Equivalent	Waste Water Disposal with DW-Inj			Waste Water Disposal with OSTT		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Levy 1%	37.80	36.52	8.22	37.71	56.69	75.59
Levy 2%	75.59	66.49	22.19	75.41	113.39	151.18
Levy 3%	113.39	96.46	47.64	113.12	170.08	226.77
1. Levy modeled as a royalty on the gross revenue from production.						
Rodgers Oil & Gas Consulting						

Table 4e.3 shows all cases to be economically viable at a price of the $100/bbl.

The case where the levy causes an overall decrease in government revenue highlights that any new fiscal instruments should not be introduced in an ad-hoc manner; they should be designed to complement the overall fiscal system.

Table 4e.3. Impacts of potential environmental levy – $100/bbl.

Green Point Shale - Potential Environmental Levy Impacts [1] USD $100/bbl Price Scenario						
(Impact on Project Net Present Value (NPV10) - CND $Real Millions)						
Royalty-Equivalent	**Waste Water Disposal with DW-Inj**			**Waste Water Disposal with OSTT**		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	1399.55	3035.86	4666.79	546.18	1900.68	3225.60
Levy 1%	1383.67	3033.47	4672.99	523.52	1875.46	3207.52
Levy 2%	1367.80	3025.57	4662.46	502.68	1850.20	3182.75
Levy 3%	1347.84	3008.61	4651.94	483.32	1824.93	3164.67
(Impacts on Project Net Cash Flow - CND $Real Millions)						
Royalty-Equivalent	**Waste Water Disposal with DW-Inj**			**Waste Water Disposal with OSTT**		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Base Case	3,099	5,714	8,339	1,868	3,981	6,099
Levy 1%	3,080	5,712	8,348	1,840	3,950	6,077
Levy 2%	3,060	5,702	8,336	1,817	3,918	6,047
Levy 3%	3,034	5,682	8,323	1,797	3,886	6,026
Incremental Government Revenue from Levy (Undiscounted) - CND $Real Millions						
Royalty-Equivalent	**Waste Water Disposal with DW-Inj**			**Waste Water Disposal with OSTT**		
Levy Rate	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Levy 1%	19.56	2.24	-8.96	27.32	31.55	21.28
Levy 2%	39.08	11.53	3.43	50.92	63.35	51.96
Levy 3%	64.93	32.41	15.84	70.83	95.14	73.24
1. Levy modeled as a royalty on the gross revenue from production.						
Rodgers Oil & Gas Consulting						

4f. Discount Rate Sensitivity

It is common practice when evaluating oil and gas investments to apply a 10% real discount rate to account for inflation, opportunity cost, and time-related risk. Projects that yield a positive net present value at this discount rate are considered economically viable, prior to considering geological and non-time-related development risks.

Geological and development risks are typically assessed through expected monetary value (EMV) analysis. The potential impacts of these risks are also often tested by applying a higher discount rate, typically 15% or 20%. Figure 4f.1 illustrates these impacts for both waste water disposal options under the $85/bbl price scenario. Only the 150 MM bbls reserves case is used to illustrate the discount rate impacts.

Figure 4f.1 shows that the base case 150 MM bbls reserves size at $85/bbl is economically viable, even at a 20% discount rate, and for the higher cost OSTT waste water disposal option. The associated value in Table 4f.1 shows a positive NPV of $322.51 MM.

Figure 4f.1. Discount rate sensitivity – $85/bbl.

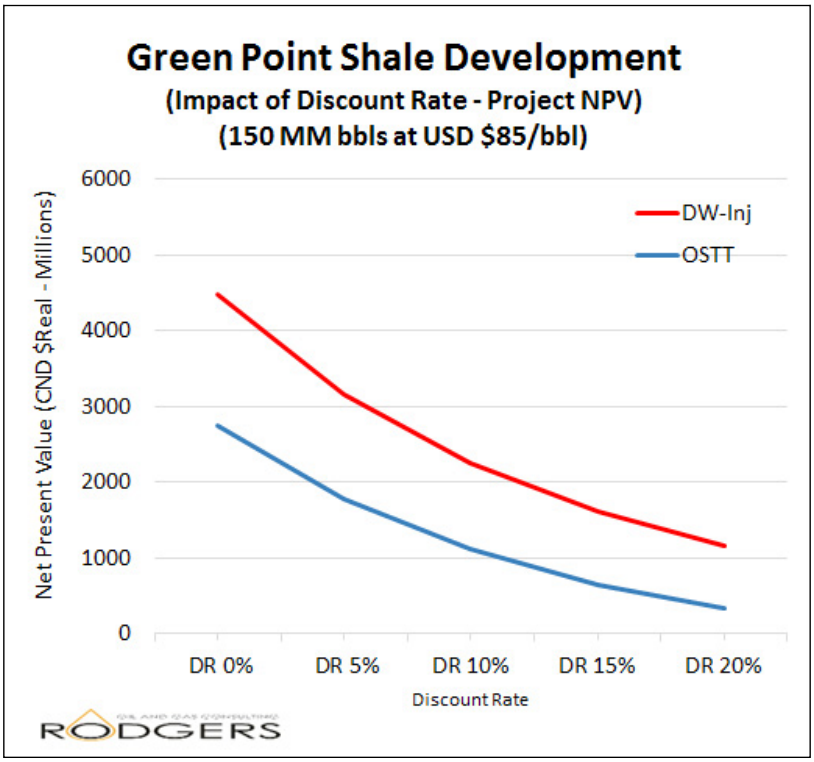


Table 4f.1. Discount rate sensitivity results.

Green Point Shale - Project NPV (Impact of Discount Rate on Project Viability)		
CND $Real Millions		
Price @ USD $85/bbl - 150 MM bbls		
	Wast Water Disposal Option	
	DW-Inj	**OSTT**
DR 0%	4473.88	2742.33
DR 5%	3164.11	1771.63
DR 10%	2261.39	1112.02
DR 15%	1620.71	651.46
DR 20%	1154.57	322.51
Price @ USD $50/bbl - 150 MM bbls		
	Wast Water Disposal Option	
	DW-Inj	**OSTT**
DR 0%	1632.59	-567.52
DR 5%	928.31	-857.30
DR 10%	455.76	-1023.97
DR 15%	130.69	-1117.20
DR 20%	-97.50	-1165.70
Price @ USD $100/bbl - 150 MM bbls		
	Wast Water Disposal Option	
	DW-Inj	**OSTT**
DR 0%	5713.96	3981.26
DR 5%	4131.58	2747.32
DR 10%	3035.86	1900.68
DR 15%	2254.25	1302.85
DR 20%	1682.45	870.36
DW-Inj = Deep Well Injection.		
OSTT = Off-Site Transport &Treatment		
Rodgers Oil & Gas Consulting		

When the $50/bbl price scenario is considered the OSTT option is shown to be uneconomic at all discount rates as illustrated in Figure 4f.2. The DW-Inj option is marginal to sub-economic at the 20% discount rate, but economic at all other rates.

At the $100/bbl price scenario illustrated in Figure 4f.3, the 150 MM bbls case is economic at all discount rates, under both the DW-Inj and OSTT options.

Only the $85/bbl price scenario is considered in illustrating the impact of a 20% discount rate. The 20% discounted values for all cases are included with the cash flows in Annex 5.

Figure 4f.2. Discount rate sensitivity – $50/bbl.

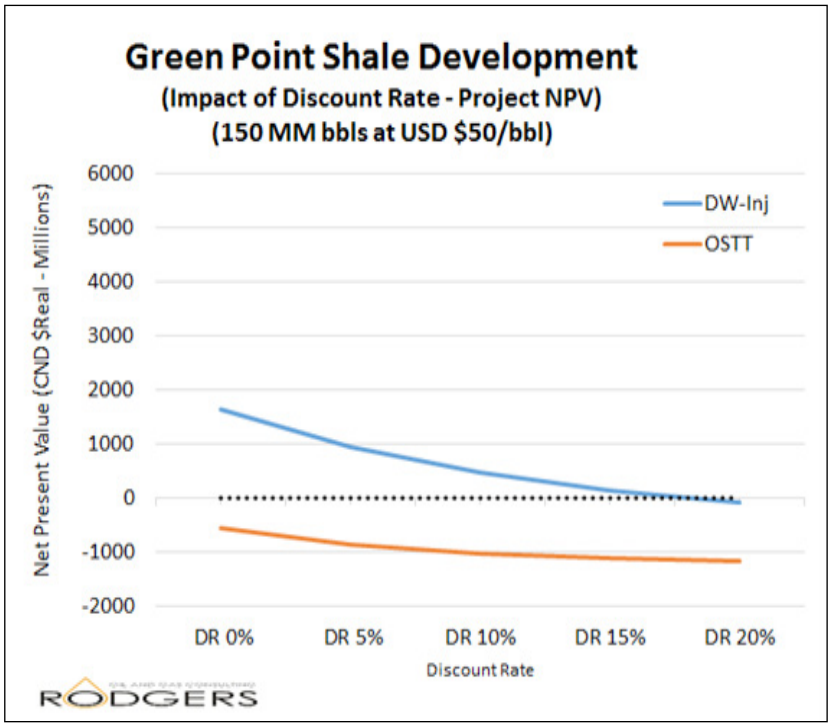
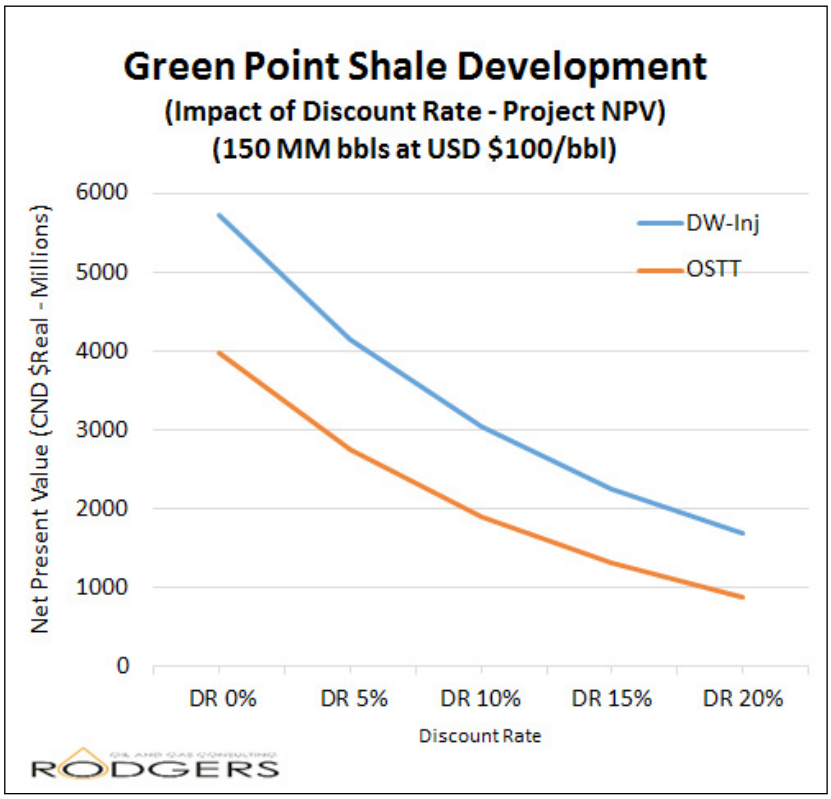


Figure 4f.3. Discount rate sensitivity – $100/bbl.



4g. Exchange Rate Sensitivity

This section looks at the impacts of changing the United States/Canadian dollar exchange rate. The base case exchange rate is 0.90. Exchange rates of 0.80 and parity (1.00) are considered below.

Discussion is around the NPV results for the $85/bbl, $50/bbl, and $100/bbl price cases, respectively. Both waste water disposal options are considered, along with the three reserves sizes – 100 MM bbls, 150 MM bbls, and 200 MM bbls.

Table 4g.1 presents the impacts on project NPV. The accompanying Table 4g.2 presents the associated impacts on IRR.

Table 4g.1. Impacts of exchange rate sensitivity – NPV.

Green Point Shale - Exchange Rate Sensitivity Project Net Present Value (NPV10) - CND $Real Millions						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
USD $50 Price	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Exch. @ 0.80	-141.05	775.94	1,675.86	-1,322.35	-584.55	117.79
USD/CND Exch. 0.90	-413.33	455.76	1,222.78	-1,620.48	-1,023.97	-441.65
Exch. @ 1.00	-646.55	197.97	897.74	-1,859.02	-1,378.91	-902.00
USD $85 Price						
Exch. @ 0.80	1,241.01	2,812.29	4,366.10	411.23	1,663.35	2,917.22
USD/CND Exch. 0.90	893.77	2,261.39	3,640.94	7.36	1,112.02	2,205.60
Exch. @ 1.00	583.85	1,829.82	3,050.17	-366.43	656.43	1,594.79
USD $100 Price						
Exch. @ 0.80	1,824.14	3,680.10	5,517.53	989.46	2,546.45	4,090.07
USD/CND Exch. 0.90	1,399.55	3,035.86	4,666.79	546.18	1,900.68	3,225.60
Exch. @ 1.00	1,055.25	2,512.10	3,986.54	214.14	1,380.15	2,547.75
Rodgers Oil & Gas Consulting						

Table 4g.2. Impacts of exchange rate sensitivity – IRR.

Green Point Shale - Exchange Rate Sensitivity Project Internal Rate of Return ($Real)						
	With Deep Injection (DW-InJ)			Without Deep Injection (OSTT)		
USD $50 Price	100 MM bbls	150 MM bbls	200 MM bbls	100 MM bbls	150 MM bbls	200 MM bbls
Exch. @ 0.80	7.7%	23.2%	38.4%	-10.0%	1.3%	11.7%
USD/CND Exch. 0.90	3.3%	17.7%	30.8%	-14.9%	-5.5%	3.4%
Exch. @ 1.00	-0.5%	13.3%	25.2%	-19.0%	-11.2%	-3.6%
USD $85 Price						
Exch. @ 0.80	31.1%	57.0%	81.3%	16.2%	35.8%	54.7%
USD/CND Exch. 0.90	25.2%	48.1%	70.0%	10.1%	27.2%	44.0%
Exch. @ 1.00	19.9%	41.0%	60.7%	4.6%	20.0%	34.6%
USD $100 Price						
Exch. @ 0.80	40.9%	70.7%	99.2%	25.3%	49.3%	72.0%
USD/CND Exch. 0.90	33.8%	60.6%	86.0%	18.4%	39.4%	59.4%
Exch. @ 1.00	28.0%	52.1%	75.5%	13.2%	31.3%	49.2%
Rodgers Oil & Gas Consulting						

Figure 4g.1 below for the $85/bbl case, shows the exchange rate changes to be significant. For example, the economics of the project at the $85/bbl price as measured by NPV10 are shown to improve from a marginal $7.36 MM (not visible on the chart) to $411.23 MM if the exchange rate changes from 0.90 to 0.80. Alternatively, the NPV10 deteriorates to -$366.43 if the exchange rate moves to parity at 1.00 (Table 4g.1).

Because exchange rate in this analysis only affects the price, the relative impacts are larger for the smaller reserves cases. An exchange rate change from 1.00 to 0.80 doubles the NPV for the 100 MM bbls DW-Inj case at $85/bbl; an increase from $583.85 MM to $1,241.01 MM. The corresponding impact for the 150 MM bbls DW-Inj case sees the NPV increase by 54%, from $1,829.82 MM to $2,812.29 MM (Table 4g.1).

Further illustration is provided by considering the $50/bbl price case – see Figure 4g.2. The poor economics for the OSTT option are clearly evident with generally negative NPVs. For the 200 MM bbls OSTT scenario an improved exchange rate from 1.00 to 0.80 changes the project from uneconomic to marginal. The NPV for the 150 MM bbls DW-Inj case would be improved from $197.97 MM to $775.94 MM (Table 4g.1).

Figure 4g.1. Exchange rate sensitivity – $85/bbl.

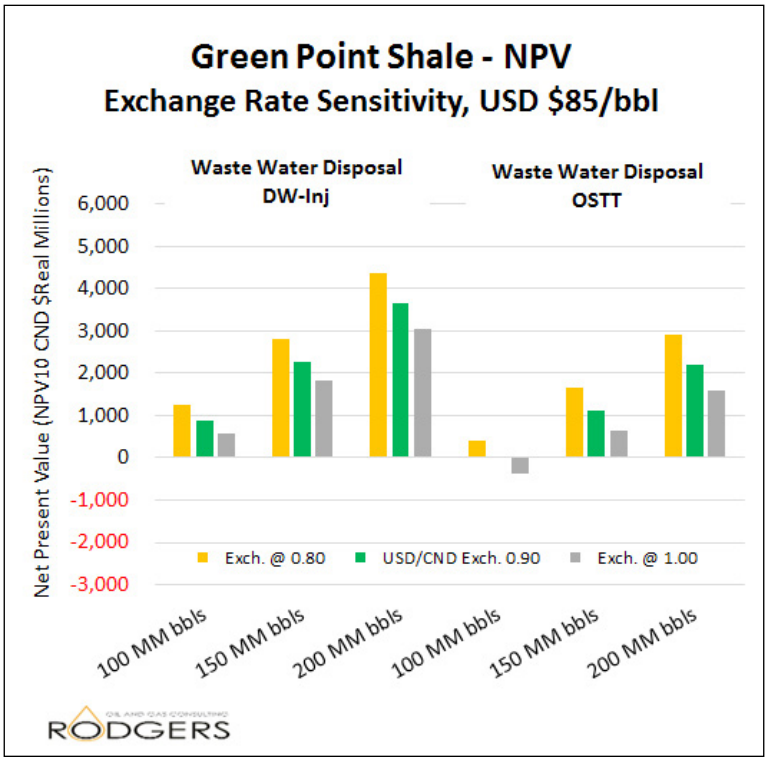


Figure 4g.2. Exchange rate sensitivity – $50/bbl.

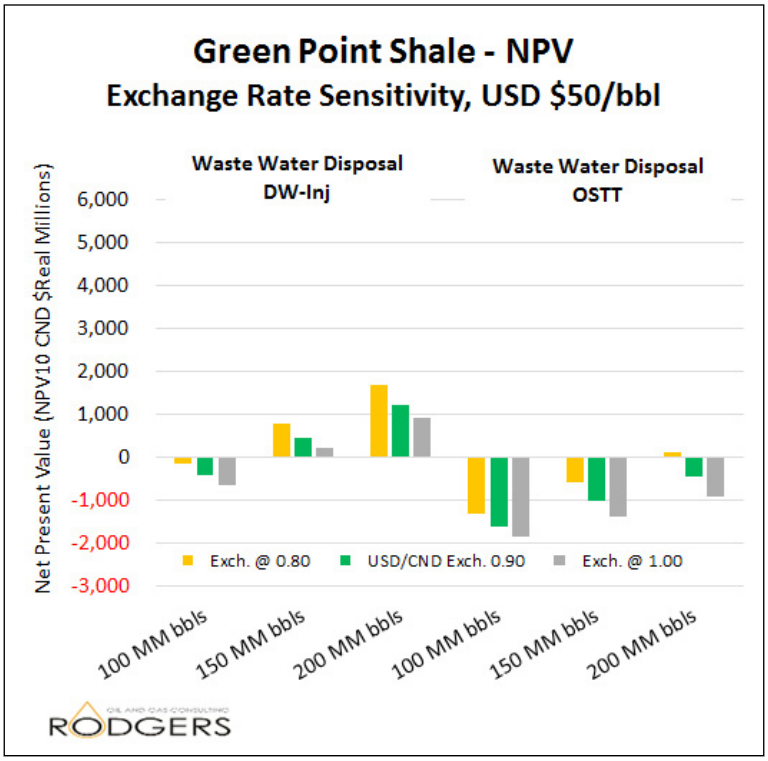
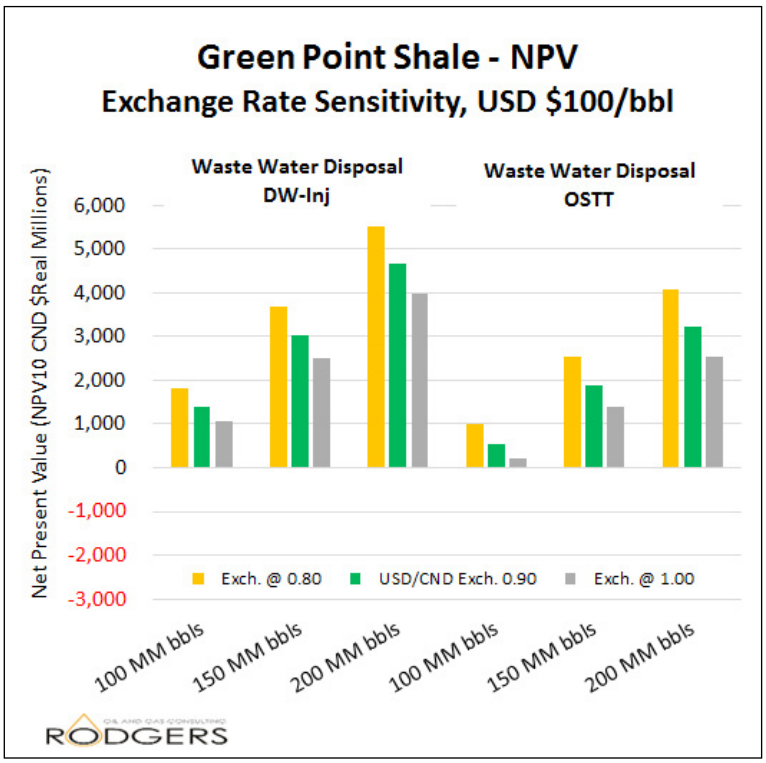


Figure 4f.3 shows the impacts for the $100 MM bbls price case. The exchange rate impact on project viability becomes generally less significant as price increases, although the significant improvement for the marginal 150 MM bbls – OSTT scenario is clearly evident.

Figure 4g.3. Exchange rate sensitivity – $100/bbl.



4h. General Sensitivities – Spider Chart

Risk associated with the key project parameters – price, recoverable reserves, CapEx, and OpEx is assessed with the help of Figure 4h.1. This figure is sometimes referred to as a spider chart, showing, in this case, the impact on producer NPV of plus-minus 45 percent changes, separately, in each of the identified parameters.

Explanation of the Chart: Reference is first drawn to the solid black horizontal line representing project breakeven, below which the project would be considered uneconomic, and the dashed black horizontal line illustrating what is considered to be the most likely profitability level. The difference between the solid black and dashed black lines shows the base case economics to be quite robust, indicating a NPV10 of $2,261. Even if total CapEx were increased by 45%, the economics would still be strong with a NPV of $1,438 million. Also refer to Table 4h.1.

Table 4h.1. General sensitivity analysis results.

General Sensitivity Analysis Results							
Net Present Value (NPV10) - CND $ MM Real							
DW-Inj Waste Water Disposal Option							
150 MM bbls, Price @ 94.44 (USD $85)/bbl, CapEx @ $27.22/bbl, OpEx @ $5.59/bbl							
	Sensitivity Range						
Parameter/Variable	Base -45%	Base -30%	Base -15%	Base	Base +15%	Base +30%	Base +45%
Price	318.32	976.54	1626.20	2261.39	2900.60	3553.01	4197.20
Reserves	333.14	991.81	1630.89	2261.39	2896.20	3544.32	4184.31
CapEx	3075.20	2809.90	2536.97	2261.39	2000.84	1707.75	1437.77
OpEx	2344.58	2313.46	2290.07	2261.39	2227.38	2196.63	2173.00
Base Case	2,261.39	2,261.39	2,261.39	2,261.39	2,261.39	2,261.39	2,261.39
OSTT Waste Water Disposal Option							
150 MM bbls, Price @ 94.44 (USD $85)/bbl, CapEx @ $26.85/bbl, OpEx @ $30.40/bbl							
	Sensitivity Range						
Parameter/Variable	Base -45%	Base -30%	Base -15%	Base	Base +15%	Base +30%	Base +45%
Price	-1197.27	-324.83	471.41	1112.02	1763.71	2421.33	3049.06
Reserves	-1148.84	-281.89	470.88	1112.02	1755.00	2415.27	3032.32
CapEx	1936.95	1677.15	1389.52	1112.02	839.45	567.20	270.57
OpEx	1740.26	1520.46	1326.36	1112.02	911.84	685.79	488.22
Base Case	1,112.02	1,112.02	1,112.02	1,112.02	1,112.02	1,112.02	1,112.02
Rodgers Oil & Gas Consulting Results							

As indicated by the slope of the lines, the most critical parameters to economic success are price (solid green line) and recoverable reserves, with changes in operating costs (dashed red line) generally having the least impact on overall project profitability. Note that the dashed green line is covered exactly by the solid green line. This results from changes in price or recoverable reserves having in this analysis the same impact on project revenues and fiscal calculations.

Discussion of Figure 4h.1: DW-Inj Option: A decrease in price or recoverable reserves by 45% would still show a positive NPV in the order of $318 to $330 million. Also see accompanying Table 4h.1. This indicates that with no change in the other parameters, the project would be economically viable at a field price of CND $50.84 (USD $45.76) per bbl or a reserves size of 75 MM bbls. Similarly, CapEx could increase by 45% and still leave an attractive NPV in of $1,438, as indicated by the solid red line.

Discussion of Figure 4h.2: **OSTT Option: While the DW-Inj option is shown to be able to withstand a 45% decrease in price or reserves size, or a 45% increase in CapEx, the OSTT option is shown to record a strong negative NPV at this sensitivity level.**

It can be seen that the green line crosses the zero-axis (zero NPV) at a price or reserves decrease between 15% and 30%. With no changes in any of the other parameters, interpolating a 25% decline indicates a breakeven price in the order of USD $65/bbl or a minimum reserves size of 112 MM bbls. This observation is consistent with the above analysis; for example, the 10.11% IRR presented for the 100 MM bbls case in Table 4b.1.

Figure 4h.1. General sensitivity analysis – DW-Inj option.

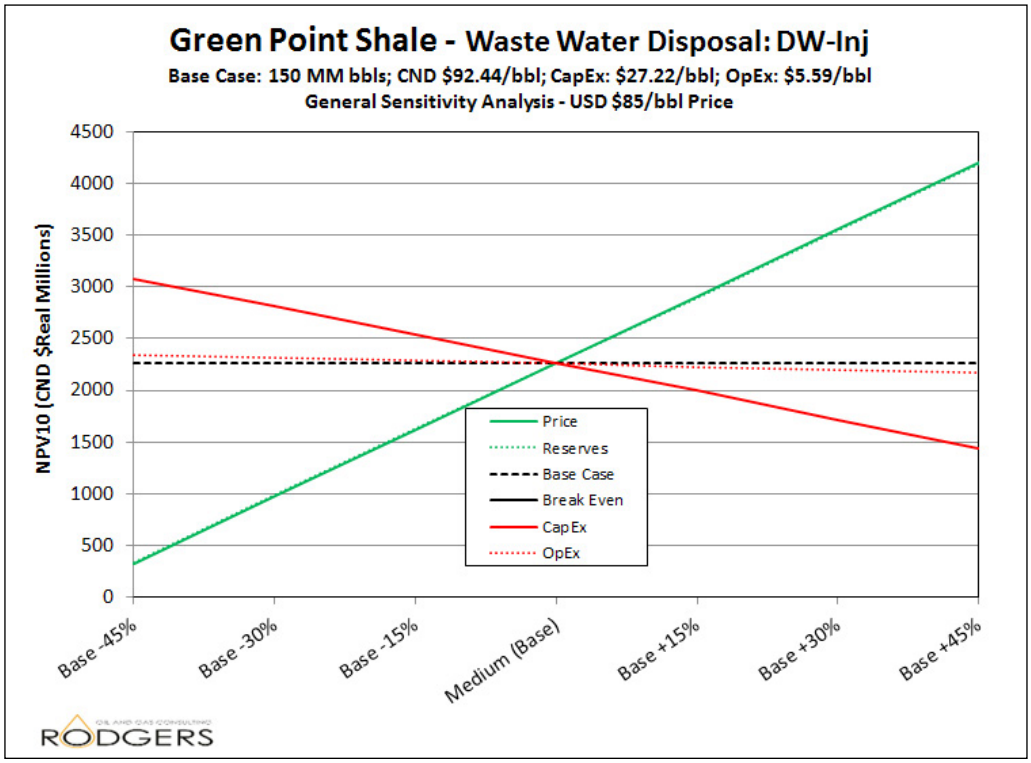
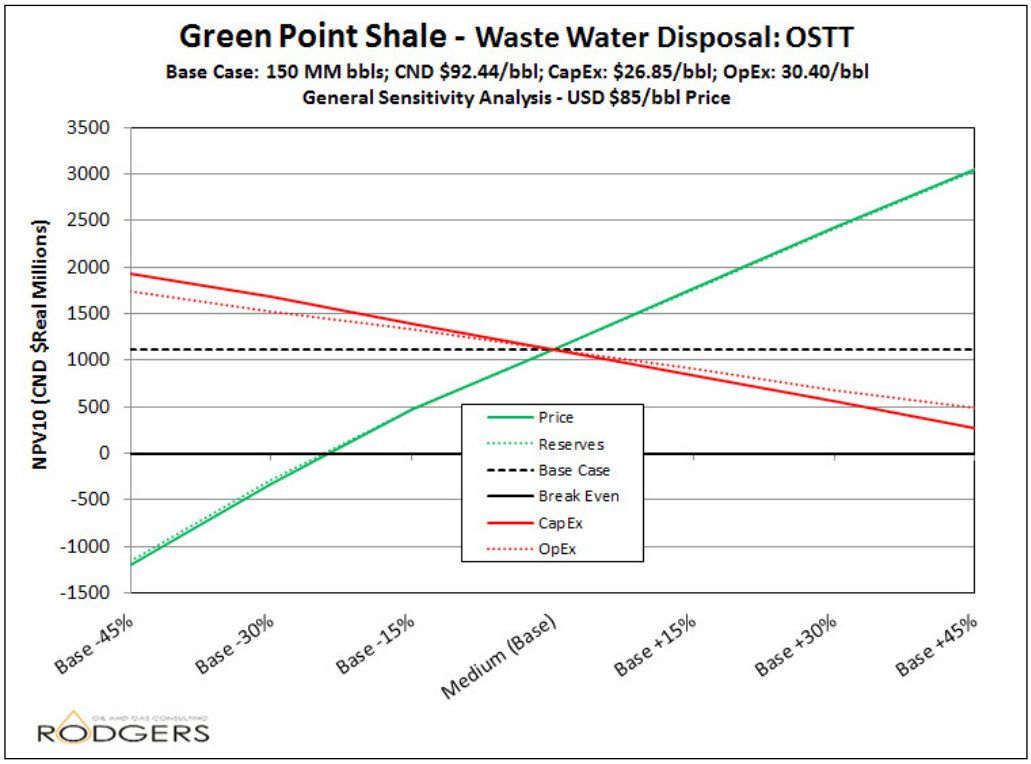


Figure 4h.2. General sensitivity analysis – OSTT option.



4i. Risk Analysis – Expected Monetary Value

Due to a lack of detailed data and information at this early stage of project development a fully comprehensive expected monetary value (EMV) analysis is not practical.[38] Directional assumptions are made, however, in order to illustrate order-of-magnitude impacts.

Table 4i.1 records the EMV result. The associated economic indicator results for the base cases are also presented. The EMV result reflectS the probabilities for the success case as indicated in the table, and described in Figure 4i.1.

Table 4i.1. Expected monetary value – $85/bbl.

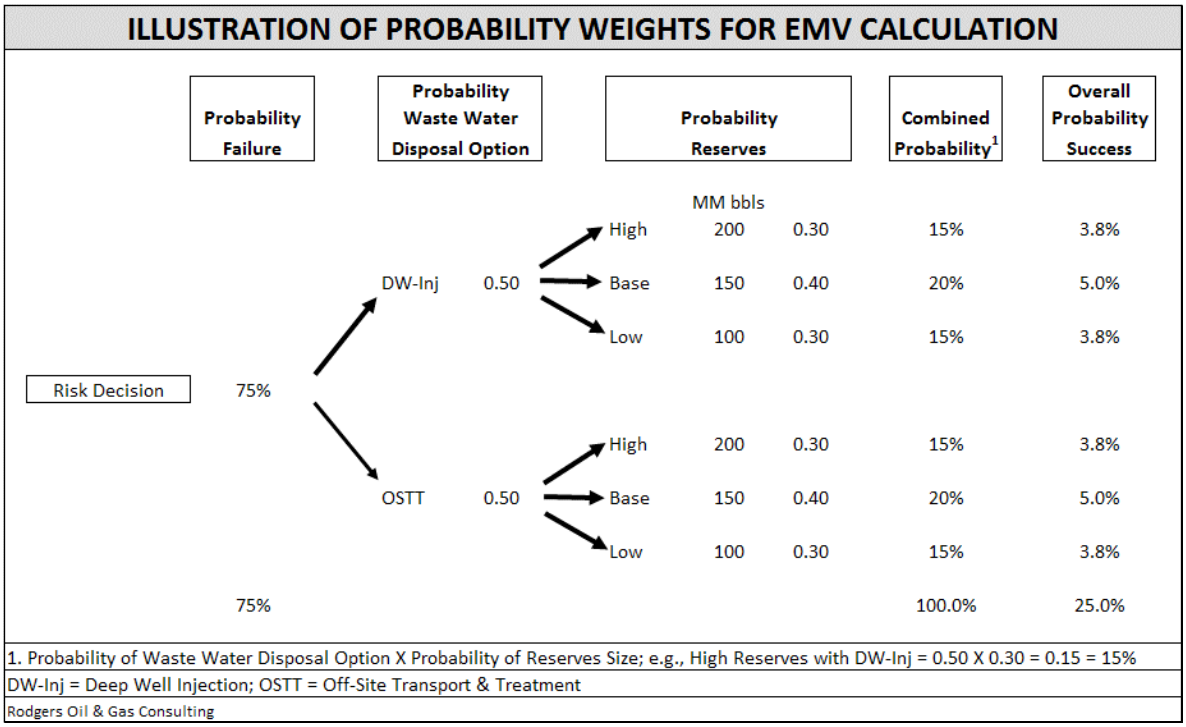
Green Point Shale - EMV & Fiscal Health Report (Oil Project)							
	CAN.NL West Coast Shale USD $85 Brent Reference				Green Point Shale		
	Canada		Nfld.&Lab.		Offshore		
	Fiscal System: CAN.NL-Generic Offshore ROR-NoSR				Oil	$ Real	(CND MM)
Oil Wells/Fields							
Investment Objective	**Fiscal Health Criteria** (Measured in $ Real Values)	Waste Water - Deep Well Injection (DW-Inj)			Waste Water - Off Site Transport & Treatment (OSTT)		
		100 MM bbl Inj	150 MM bbl Inj	200 MM bbl Inj	100 MM bbl NoInj	150 MM bbl NoInj	200 MM bbl NoInj
Risk Management	Probability	15%	20%	15%	15%	20%	15%
	EMV - Oil Only	396.32					
	Payout (Yrs)	3.86	2.44	1.77	5.84	3.76	2.63
Capital Efficiency	Rate of Return (ROR)	**25.19%**	**48.06%**	**70.03%**	**10.11%**	**27.16%**	**44.00%**
	Profit to Investment Ratio (PIR10)	0.28	0.71	1.14	0.00	0.35	0.70
	NPV10 / bbl	8.29	13.96	16.84	0.07	6.87	10.21
	NCF / bbl	21.36	27.62	30.93	9.96	16.95	20.69
Wealth Generation	Gross Netback Revenue	9,204.37	13,823.78	18,448.74	9,188.71	13,806.57	18,431.68
	Capital Costs	-4,083.31	-4,083.31	-4,083.31	-4,027.51	-4,027.51	-4,027.51
	Operating Costs	-558.94	-738.03	-917.31	-3,215.38	-4,429.08	-5,644.68
	Net Revenue	4,562.12	9,002.44	13,448.13	1,945.83	5,349.98	8,759.50
	Net Cash Flow (NCF)	2,303.60	4,473.88	6,688.04	1,072.26	2,742.33	4,468.19
	Net Present Value (NPV10)	893.77	2,261.39	3,640.94	7.36	1,112.02	2,205.60
	Government Revenue	2,258.52	4,528.56	6,760.09	873.56	2,607.65	4,291.32
Fiscal Health	Fiscal Cost Index (FCI) - GovRev/boe	20.85	27.87	31.20	8.06	16.05	19.81
	Government Share (GT0%)	**49.51%**	**50.30%**	**50.27%**	**44.89%**	**48.74%**	**48.99%**
Rodgers Oil & Gas Consulting							

Figure 4i.1 illustrates the assumed 50% chance that the high-cost off-site waste water transport and treatment option (OSTT) will be necessary and that the probabilities for the Low, Base, and High reserves success cases reflect a Swanson's Mean[39] value based, respectively, on probabilities of 30%, 40%, and 30%.

[38] Expected Monetary Value (EMV) is determined by summing the products of the various NPV outcomes and their associated probabilities of success or failure.

[39] Named after a former Exxon geologist, Roy Swanson. Swanson's Mean refers to a particular way of calculating a single value to represent the entire reserves distribution. Specifically, to calculate the "mean" value from the probability distribution the weights assigned to the P_{10}, P_{50}, and P_{90} reserves estimates are respectively 30%, 40%, and 30%.

Figure 4i.1. Illustration of EMV probability weights.



The assumed probability of overall success is 25%, implying a failure probability of 75% and the overall probability of success for each reserves scenario as shown in Figure 4i.1. In other words, the EMV analysis assumes a 75% chance that the project will not be economically viable and, if it is viable, the development would reflect the probabilities assigned in Table 4i.1 from Figure 4i.1.

Discussion of the Table: Table 4i.1 provides the economic decision-making criteria results for the three reserve sizes modeled, under the two waste water disposal options. Results are for the USD $85/bbl case. The fiscal terms are the generic Newfoundland and Labrador offshore terms (CAN.NL-Generic Offshore ROR – NoSR), without Nalcor participation.[40]

The table shows four results-groupings reflecting alternative management objectives – Risk Management, Capital Efficiency, Wealth Generation, and Fiscal Health.

Risk Management: Measures recorded in this report for assessing overall project risk are expected monetary value (EMV) and payout time (years) to recover project investments and operating costs. There are other measures of risk that are sometimes identified. These include the maximum probability of failure (MPF) that the project could withstand and still achieve the minimum breakeven EMV10 value. Another risk-measure not modeled here is the VRI – value to risk index. When comparing projects, particularly across diverse geological basins or technologies, investors will be interested in the VRI, which is simply the EMV10 divided by the standard deviation of EMV results for each scenario modeled. This provides an indication of the value per unit of risk, with risk measured by the standard deviation from the mean value. Due to the need for more precise data, and because this analysis is assessing more-or-less comparable projects, these additional risk management indicators are not discussed further.

[40] Refer to the summary of fiscal terms in Table 2e.1. The "NoSR" reference is to clarify that the supplemental or super royalty increment applicable to some offshore projects is not part of the generic fiscal system, and therefore not modeled for this analysis.

Capital Efficiency: The full suite of typically applied measures of capital efficiency are included – internal rate of return, indicating the degree to which project net revenues exceed project costs, including the time-value of money; the discounted profit to investment ratio (PIR10), indicating the NPV10 per dollar of investment; and NPV10/bbl and NCF/bbl, showing project attractiveness in terms of per unit produced.

Wealth Generation: While capital efficiency is measured through a consideration of various ratios, wealth generation measures revenue or net revenue – gross net-back revenue (NBR) – sales revenue at the lease boundary, CapEx and OpEx, Net Revenue (NR = NBR - CapEx - OpEx), net cash flow (NCF = NR - Government Revenue (GR)), and NPV = discounted NCF. The typical discount rate is 10%, although each investor will have its own specific discount rate based on its risk-adjusted weighted average cost of capital. (WACC).

Fiscal Health: Only two fiscal health measure are recorded for this analysis – Government share (GS%) and the fiscal cost index (FCI). GS% is the share of project revenue paid to governments, expressed as a percentage of project net revenue. The FCI is the government revenue per barrel produced. This is a useful indicator of the price that the government charges for access to resources. Expressed on a per unit basis, the FCI affords ready comparison with the oil or gas price, and with per unit CapEx and OpEx.

Since this analysis does not discuss the performance details of the fiscal system, other fiscal health measures such as the degree of fiscal front-end loading, the degree of fiscal progressivity, or the cost-savings index are not discussed.[41]

Many of the values recorded in Table 4i.1 have already been presented in Tables 4a.3 and 4b.1; they are reproduced here for context and convenience. In addition to the EMV, two values in the table that were not previously discussed but are highlighted here are payout and government share.

Payout time for Green Point Shale development options identified ranges, depending on the reserves size, from approximately 2-4 years under the DW-Inj option and 3-6 years for the OSTT option.

Government share is consistently in the order of 50% – a range of 48.74% to 50.30%.

Overall EMV: The overall profitability of the prospective development is reflected in a positive EMV of $396.32 MM. Equivalent values for the $50/bbl and $100/bbl price cases are -$100.77 MM and $590.37 MM. See Tables 4i.2 and 4i.3.

Weighting each of these values according to an assumed probability that each of the three price scenarios will actually occur, adds an important adjustment to the overall EMV or risked values presented above.

The price probabilities assigned to each scenario are 70% for the $85/bbl scenario, 20% for the $50/bbl scenario, and 10% for the $100/bbl scenario.

The overall EMV is thus calculated as:

0.20 X - $100.77 + 0.70 x $396.32 + 0.10 x $590.37 = $316.31 MM

An overall positive EMV10 value of $316.31 indicates attractive project economics, even after accounting for geological and development risks. This does not necessarily mean that full scale project investments should

[41] Front end loading refers to the portion of the government share before the start of production and before project payout. Fiscal progressivity refers to the direction of the government share in relation to changes in key variables such as price; systems that produce an increasing government share in percentage terms as price increases are referred to as progressive; systems where the government share decreases as price increases are regressive. The cost-savings index (CSI) measures the incentive under the fiscal system for investors to reduce costs.

necessarily be made. It does mean, however, that the project appears to be attractive enough to move to the next stage, and consider drilling another well with the hope of confirming the reserve size estimates and costs.

Table 4i.2. Expected Monetary Value – $50/bbl.

Green Point Shale - EMV & Fiscal Health Report (Oil Project)							
	CAN.NL West Coast Shale USD $50 Brent Reference				Green Point Shale		
	Canada		Nfld.&Lab.		Offshore		
	Fiscal System: CAN.NL-Generic Offshore ROR-NoSR				Oil	$ Real	(CND MM)
Oil Wells/Fields							
Investment Objective	**Fiscal Health Criteria** (Measured in $ Real Values)	**Waste Water - Deep Well Injection (DW-Inj)**			**Waste Water - Off Site Transport & Treatment (OSTT)**		
		100 MM bbl Inj	150 MM bbl Inj	200 MM bbl Inj	100 MM bbl NoInj	150 MM bbl NoInj	200 MM bbl NoInj
Risk Management	Probability	15%	20%	15%	15%	20%	15%
	EMV - Oil Only	-100.77					
	Payout (Yrs)	7.92	4.87	3.42	25.00	25.00	7.81
Capital Efficiency	Rate of Return (ROR)	**3.33%**	**17.65%**	**30.77%**	**-14.93%**	**-5.49%**	**3.39%**
	Profit to Investment Ratio (PIR10)	-0.13	0.14	0.38	-0.51	-0.32	-0.14
	NPV10 / bbl	-3.84	2.82	5.67	-15.08	-6.34	-2.05
	NCF / bbl	3.00	10.09	13.09	-14.10	-3.51	1.65
Wealth Generation	Gross Netback Revenue	5,323.34	7,998.62	10,664.82	5,310.74	7,985.01	10,646.68
	Capital Costs	-4,083.31	-4,083.31	-4,083.31	-4,027.51	-4,027.51	-4,027.51
	Operating Costs	-541.62	-720.65	-882.36	-3,192.98	-4,406.23	-5,597.07
	Net Revenue	698.41	3,194.66	5,699.15	-1,909.74	-448.72	1,022.10
	Net Cash Flow (NCF)	322.88	1,632.59	2,823.94	-1,515.06	-567.52	355.05
	Net Present Value (NPV10)	-413.33	455.76	1,222.78	-1,620.48	-1,023.97	-441.65
	Government Revenue	375.53	1,562.07	2,875.21	-394.68	118.80	667.04
Fiscal Health	Fiscal Cost Index (FCI) - GovRev/boe	3.47	9.61	13.27	-3.64	0.73	3.08
	Government Share (GT0%)	**53.77%**	**48.90%**	**50.45%**	**20.67%**	**-26.48%**	**65.26%**
Rodgers Oil & Gas Consulting							

Table 4i.3. Expected Monetary Value – $100/bbl.

Green Point Shale - EMV & Fiscal Health Report (Oil Project)							
	CAN.NL West Coast Shale USD $100 Brent Reference				Green Point Shale		
	Canada		Nfld.&Lab.		Offshore		
	Fiscal System: CAN.NL-Generic Offshore ROR-NoSR				Oil	$ Real	(CND MM)
Oil Wells/Fields							
Investment Objective	**Fiscal Health Criteria** (Measured in $ Real Values)	**Waste Water - Deep Well Injection (DW-Inj)**			**Waste Water - Off Site Transport & Treatment (OSTT)**		
		100 MM bbl Inj	150 MM bbl Inj	200 MM bbl Inj	100 MM bbl NoInj	150 MM bbl NoInj	200 MM bbl NoInj
Risk Management	Probability	15%	20%	15%	15%	20%	15%
	EMV - Oil Only	590.37					
	Payout (Yrs)	3.17	2.00	1.46	4.86	2.85	2.04
Capital Efficiency	Rate of Return (ROR)	**33.81%**	**60.56%**	**86.03%**	**18.35%**	**39.44%**	**59.40%**
	Profit to Investment Ratio (PIR10)	0.44	0.95	1.46	0.17	0.60	1.02
	NPV10 / bbl	12.96	18.74	21.59	5.06	11.73	14.92
	NCF / bbl	28.70	35.27	38.57	17.31	24.58	28.21
Wealth Generation	Gross Netback Revenue	10,877.39	16,316.11	21,774.92	10,863.85	16,316.11	21,774.92
	Capital Costs	-4,083.31	-4,083.31	-4,083.31	-4,027.51	-4,027.51	-4,027.51
	Operating Costs	-576.12	-738.03	-917.31	-3,236.21	-4,450.31	-5,665.87
	Net Revenue	6,217.97	11,494.77	16,774.31	3,600.14	7,838.29	12,081.55
	Net Cash Flow (NCF)	3,099.38	5,713.96	8,339.27	1,867.64	3,981.26	6,098.78
	Net Present Value (NPV10)	1,399.55	3,035.86	4,666.79	546.18	1,900.68	3,225.60
	Government Revenue	3,118.59	5,780.81	8,435.04	1,732.50	3,857.03	5,982.77
Fiscal Health	Fiscal Cost Index (FCI) - GovRev/boe	28.79	35.57	38.93	15.99	23.74	27.61
	Government Share (GT0%)	**50.15%**	**50.29%**	**50.29%**	**48.12%**	**49.21%**	**49.52%**
Rodgers Oil & Gas Consulting							

ANNEX 1: SCOPE OF WORK

Scope of Work: Project parameters, including expected recoverable reserves (EUR) and costs will be developed in consultation with Dr. Wade Locke.

Costs will include detailed subcategories for capital costs (CapEx) and operating costs (OpEx). Sufficient detail will be provided so as to identify the major cost categories and facilitate appropriate fiscal calculations.

The EUR cases will include parameters for determining the production profile for each type-well and for the full field development case.

Other parameters to be identified and described include the assumed rates of inflation and escalation for prices and costs, and the CND/USD exchange rate.

Economic results will be based on the generic offshore fiscal terms for Newfoundland and Labrador.

The report will include base case analysis, sensitivity analysis, and risk (expected monetary value – EMV) analysis. Sensitivity analysis will assess three levels of expected recoverable reserves (EUR) – 100 MM bbls, 150 MM bbls, and 200 MM bbls. Each EUR case will be assessed at three USD-equivalent oil price levels – $50, $85, and $100 per bbl. In addition, each price-EUR combination will be assessed for two waste water disposal options – deep well injection and off-site transport and treatment. Sensitivity analysis will also include assessing the base cases with a range of positive and negative changes in each of EUR, CapEx, OpEx, and price.

Due to the early stage of this development, detailed probability estimates are not available. Never the less the consultant will select representative parameters in order to illustrate the directional impact of this analysis on the ultimate view of project viability.

Sensitivity analysis will also be performed to illustrate the effects of well drilling and completion costs, discount rate, and a potential environmental impact levy.

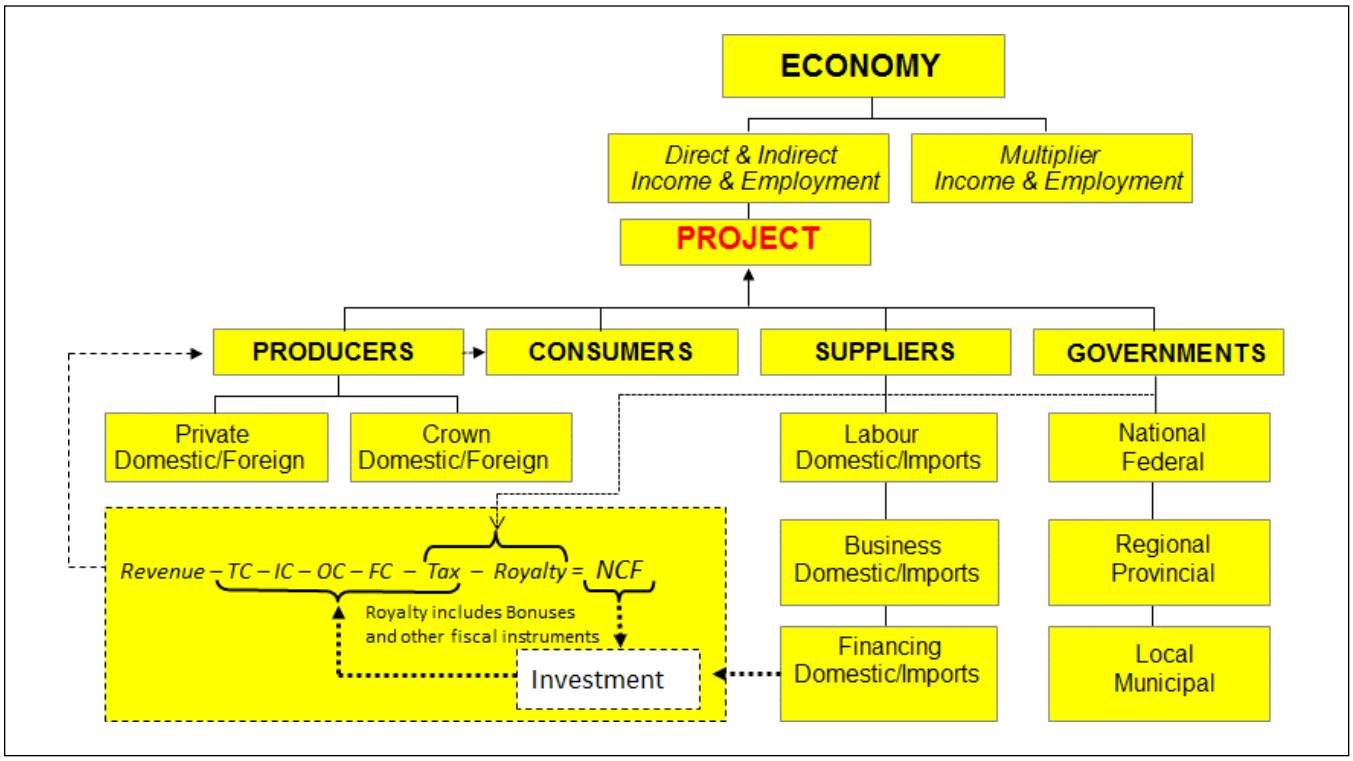
Results will be reported in both nominal and real terms.

The report will include, but not necessarily be limited to, the cases and parameters identified by Dr. Locke.

The standard suite of economic decision-making parameter results will be; they are presented reported for each analysis case, including rate of return, net present value, government share, payback period, etc.

ANNEX 2: PEET® (PETROLEUM ECONOMICS EVALUATION TOOL)

A Multi-Stakeholder Modeling Approach



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Financial viability models are specifically designed to assess the value of a given project under assumed/predicted conditions. With the required input values assumed and their interrelationships determined, the output results are therefore also determined. These models are structured to: (a) provide a clear point of reference for analysis comparison – the base case, (b) manage risk and uncertainty by facilitating sensitivity analysis which serves to highlight the critical variables and their impacts on project profitability, and (c) assess the level of project risk by weighting the possible outcomes for each of the identified parameters by their estimated probability of occurrence.

Applied to financial cash flow analysis and project evaluation, benefit cost analysis broadens the perspective from that of the individual firm to include an accounting of the other economic sectors and factors of production that are needed for the initial investment project to become a reality. In the context of upstream investments, the CapEx and OpEx flows represent costs. However, to the suppliers of the goods and services represented by these costs they represent benefits. These are important considerations for governments when attempting to balance direct impacts to investors and the Treasury with broader economy-level impacts to local consumers, project subcontractors, and labor.

Financial viability or cash flow models are classified as deterministic, to distinguish them from stochastic (probabilistic) models such as Monte Carlo simulation models. There are basically four types of economics models – Macro Econometric, Input-Output, Financial Cash Flow, and Benefit-Cost. Benefit-Cost models are a variation of financial cash flow models.

Macro-economic models and input-output models deal with the economy as a whole. This is contrasted with financial viability and benefit cost models that are used to assess a single project within a given sector of the economy.

Macro-economic models are based on series of historical relationships representing the interaction between and among the various sectors of the economy. These models are statistical rather than deterministic; which means they incorporate an unexplained/undetermined/random component. Such models are useful for large systems analysis because the various unexplained components individually make up a relatively small component of the model's explanatory power and, with the application of proper statistical techniques, the aggregate impact of these components can be accounted for so that they do not distort model results.

Because of their aggregate and statistical nature, econometric and input-output models are of limited practical benefit in informing investment decisions related to individual projects. For project evaluation at the level of the firm or individual each input parameter/assumption needs to be precisely controlled (determined) so that the effects of the most important parameters can be isolated and repeated. An important example in this context is the fiscal system. Taxes, royalties, and other fiscal measures are prescribed in law. Because of this, these obligations can be exactly determined on the basis of the relevant input parameters assumed to represent the project(s) being evaluated. Other input parameters include costs and their classification for fiscal purposes, production profiles, and economy-wide inputs such as prices, escalation and inflation rates.

While typically not directly used in upstream project economics decision-making, Monte Carlo simulation modeling is often employed to determine estimates for key project inputs used by deterministic models. The most noteworthy example is the estimation of recoverable reserves, and the determination of the associated production profile and the required number of wells for optimal resource extraction.

PEET is a deterministic model. In this respect it is not unlike many similar models. PEET, however, expands the traditional model scope to be able to provide a snap-shot of how a project's cash flows would translate into broader economy-wide impacts. As such, PEET is specifically designed to support the full gamut of petroleum economics decision-making and multi-stakeholder analysis. The model incorporates base case, sensitivity, and risk / expected monetary value (EMV) analysis, and can recognize the perspectives of investors, governments, and suppliers of project goods and services – labor, and business inputs.

By extending the traditional cash flow analysis to recognize the impacts on project suppliers, private and state owned corporations, and various levels of government, and by permitting a high-level discrete analysis of the economy-wide benefits and costs, PEET is uniquely designed for policy development and negotiations support.

ANNEX 3: FISCAL TERMS

	NEWFOUNDLAND & LABRADOR, CANADA: OFFSHORE – ROR PROFIT SHARING
Bonuses	**Signature Bonus:** None. Work expenditure commitment bids apply. **Production Bonuses:** None
Rentals & Fees	Refundable against work expenditure commitments. Applicable in Period II (years 6 – 9) and distinguished by area: Rentals in Area "A" (more mature area) are CND $5.00 per hectare for the first year, increasing thereafter by $5.00 per hectare per year, up to and including the third year and subsequent years at $15.00 per hectare (US $1,425 per sq km). For Area "B", rentals are applicable at a rate of $2.50 per hectare for the first year, increasing thereafter by $2.50 per hectare per year, up to and including the third year and subsequent years at $7.50 per hectare (US $712 per sq km).
Royalties	Royalty rate sliding scale: 1%-7.5%. Escalation is based on the level of production and simple payout (recovery of uplifted capital, operating, and exploration costs). The rate slides as follows: before simple payout: 1% before the earlier of: (a) 50 million barrels and (b) 20% of initial established reserves; then 2.5% until 100 million barrels; 5% for the next 100 million barrels; and 7.5% thereafter; after simple payout: 5% for the next 100 million barrels and 7.5% thereafter.
Corp. Income Tax	Combined Rate: 29.00% – Federal rate @ 15.0%, plus the Provincial rate of 14.0%. Exploration costs are expensed. Land purchase and rentals costs are depreciated as Canadian Oil and Gas Property Expense (COGPE) at 10% declining balance from the date incurred. Development well intangibles are depreciated at 30% declining balance. Facilities and well tangibles are subject to the half-year convention and depreciated at 25% declining balance from the start of production/Available for Use (AFU) date. AFU rules are relaxed through the Long Term Project (LTP) rules, including the 24-month Rolling Start (RS) rule. Loss carried forward term = 20 years.
Profit Sharing	Rate sliding scale: 20% of Net Revenue after payout (recovery of previous royalty paid and uplifted capital and operating costs, plus a ROR allowance of 5% plus the long term government bond rate; and 30% after a ROR allowance of 15% plus the long term bond rate. In determining payout capital, operating, and exploration costs can be uplifted by 1%, 10%, and 5%, respectively. The gross royalty is always payable and is creditable against the profit share. If, after payout, the net revenue in any year is negative, the amount can be brought forward to be used in determining net revenue for the following year. Net Revenue is defined as: Gross Revenue less Transportation Costs – less Capital Costs less Operating costs.
Production Sharing	None
State Participation	Negotiable. Newfoundland & Labrador's Energy Plan – 2007 states its policy to obtain a 10% equity position in future oil and gas projects, including compensation, where relevant, for past exploration costs. None modeled.
Resource Taxes	None
Other Fiscal Levies	**Property Taxes:** None **Import Duties:** None modeled. Duties may apply with special rules and trade zone exemptions. **Export Tax:** Goods & Services (Value Added) Tax. Also a provincial sales tax – exempt. **Training/R&D:** Negligible – some programs are available for specifically qualifying research. **Carbon Tax:** None
Notes	A Super Royalty applies to some projects; e.g., White Rose Satellites and Hebron. These projects are liable for an additional 6.50% to the Tier 1 Royalty rate for prices in excess of US $50 per barrel. The Maximum net royalty rate can thus be 36.5% after Tier 2 payout. An incremental royalty rate also applies to Hibernia extension projects.
References	Ministry of Energy | Ministry of Finance

Source: North America Economics & Fiscal Intelligence Service – 2015 Update, Rodgers Oil & Gas Consulting.

	NEWFOUNDLAND & LABRADOR, CANADA: OFFSHORE – R-FACTOR PROFIT SHARING
Bonuses	**Signature Bonus:** None. Work expenditure commitment bids apply. **Production Bonuses:** None
Rentals & Fees	Refundable against work expenditure commitments. Applicable in Period II (years 6 – 9) and distinguished by area: Rentals in Area "A" (more mature area) are CND $5.00 per hectare for the first year, increasing thereafter by $5.00 per hectare per year, up to and including the third year and subsequent years at $15.00 per hectare (US $1,425 per sq km). For Area "B", rentals are applicable at a rate of $2.50 per hectare for the first year, increasing thereafter by $2.50 per hectare per year, up to and including the third year and subsequent years at $7.50 per hectare (US $712 per sq km).
Royalties	Royalty rate sliding scale: Based on an R-Factor, the rates are: 1.0%, for $R < 0.25$; 2.5%, for $0.25 \leq R < 1$; 5.0%, for $1 \leq R < 1.25$; and 7.5%, for $R \geq 1.25$. R is defined as per the Profit Share.
Corp. Income Tax	Combined Rate: 29.00% – Federal rate @ 15.0%, plus the Provincial rate of 14.0%. Exploration costs are expensed. Land purchase and rentals costs are depreciated as Canadian Oil and Gas Property Expense (COGPE) at 10% declining balance from the date incurred. Development well intangibles are depreciated at 30% declining balance. Facilities and well tangibles are subject to the half-year convention and depreciated at 25% declining balance from the start of production/Available for Use (AFU) date. AFU rules are relaxed through the Long Term Project (LTP) rules, including the 24-month Rolling Start (RS) rule. Loss carried forward term = 20 years.
Profit Sharing	Rate based on R-Factor: Rate sliding scale from 0%-50% of Net Revenue (NR) after payout. Payout occurs when R-Factor (R) = [(Cumulative revenue less cumulative transportation costs less cumulative royalty and profit share paid to the end of the previous year), divided by (Cumulative project capital & operating costs)] = 1. NRR = Min of (a) 50% and (b) [NRRmin + {[(R - Rmin) ÷ (Rmax - Rmin)] * (NRRmax - NRRmin) }]. NRRmin = Minimum Net Royalty Rate = 10%, NRRmax = Maximum Net Royalty Rate = 50%, Rmin = Minimum R = 1, Rmax = Maximum R = 3. The gross royalty is always payable and is creditable against the profit share. Net Revenue is defined as: Gross Revenue less Transportation Costs – less Capital Costs less Operating costs.
Production Sharing	None
State Participation	Negotiable. Newfoundland & Labrador's Energy Plan – 2007 states its policy to obtain a 10% equity position in future oil and gas projects, including compensation, where relevant, for past exploration costs.
Resource Taxes	None
Other Fiscal Levies	**Property Taxes:** None **Import Duties:** None modeled. Duties may apply with special rules and trade zone exemptions. **Export Tax:** Goods & Services (Value Added) Tax. Also a provincial sales tax – exempt. **Training/R&D:** Negligible – some programs are available for specifically qualifying research. **Carbon Tax:** None
Notes	None
References	Ministry of Energy | Ministry of Finance

Source: North America Economics & Fiscal Intelligence Service – 2015 Update, Rodgers Oil & Gas Consulting.

ANNEX 4: FISCAL CALCULATIONS

See separate Excel spread sheet for annotated tables illustrating the key royalty, profit share, & corporate tax calculations: *Annex 4 - Royalty & CIT Audit.xlsx*

ANNEX 5: ANNUAL CASH FLOWS

See separate excel spread sheet for annual cash flows in $Real and $Nominal: *Annex 5 - Annual Cash Flow Tables.xlsx*

ANNEX 6: R-FACTOR FISCAL TERMS

Preliminary Economic Results

Analysis of the R-Factor Fiscal Terms

This annex presents the project-level economics under the new generic R-Factor fiscal terms announced on November 2nd. Generally these terms are somewhat more onerous than the previous generic ROR terms used for this report.

The Province's new generic offshore fiscal terms were announced after the analysis for this report was completed. The main report therefore could not reflect these new terms.

It was decided however to test these terms to determine whether the economic results are materially affected in the context of the project risks at this stage. The $316.31 MM EMV result calculated above under the generic ROR terms is compared to $264.46 MM under the R-Factor terms.

Based on the EMV result, it is felt that, in the context of the current uncertainty around recoverable reserves, costs, and commodity prices, the new generic R-Factor terms do not make a material difference to the risk economics of the project as currently understood.

Table A1.1 and Figure A1.1 compare these results to those under the generic ROR terms for the DW-Inj waste water disposal option. Similarly, the results for the OSTT waste water disposal are presented in Table A1.2 and Figure A1.2.

Figure A1.1 below immediately shows the new fiscal terms to be more progressive with respect to government share (GS%) – compare the flat dashed blue line with the increasing yellow line. This increase in GS% is reflected in the decreases in project rate of return (IRR) illustrates by the change from the blue bars to the yellow bars.

The results for the higher cost OSTT waste water disposal option illustrated in Figure A1.2 show that the new terms are generally neutral in this profitability range. Due to a lower GS% for the ROR system, this system is shown to exhibit somewhat more progressivity.

With one exception, projects that were economically viable under the ROR terms remain viable under the new R-Factor terms. The exception being, the low reserves-$85/bbl-OSTT option where NPV10 is reduced from a marginal $7.36 MM to a negative $80.53 MM.

Table A1.1. Economic results for new R-factor terms – DW-Inj, $85/bbl.

Green Point Shale Economic Results Comparison of Generic Rate of Return-Based Terms and New R-Factor Terms Canadian Dollars - Real Values (Millions) Water Disposal - Off-Site Transport & Treatment (OSTT)									
	Recoverable Reserves								
	100 MM bbls			150 MM bbls			200 MM bbls		
United States Dollar Price Per bbl	$50	$85	$100	$50	$85	$100	$50	$85	$100
Canadian Dollar Equivalent Price [1]	$53.56	$92.44	$109.11	$53.56	$92.44	$109.11	$53.56	$92.44	$109.11
Previous Generic ROR Fiscal Terms									
Project									
Internal Rate of Return (IRR)	-14.93%	10.11%	18.65%	-5.49%	27.16%	34.99%	3.39%	44.00%	59.04%
Net Cash Flow (NCF)	-1,515.06	1,072.26	1,867.64	-567.52	2,742.33	3,981.26	355.05	4,468.19	6,098.78
Net Present Value (NPV10)	-1,620.48	7.36	546.18	-1,023.97	1,112.02	1,900.68	-441.65	2,205.60	3,225.60
Government Revenue	-394.68	873.56	1,732.50	118.80	2,607.65	3,857.03	667.07	4,291.32	5,982.77
Government Share (GS%)	20.67%	44.89%	48.12%	-26.48%	48.74%	49.21%	65.26%	48.99%	49.52%
New Generic R-Factor Fiscal Terms									
Project									
Internal Rate of Return (IRR)	-15.00%	8.79%	17.28%	-5.05%	25.79%	37.35%	3.29%	41.51%	56.08%
Net Cash Flow (NCF)	-1,525.87	910.84	1,757.72	-531.43	2,604.95	3,733.92	341.62	4,154.63	5,554.48
Net Present Value (NPV10)	-1,628.58	-80.53	475.32	-1,010.68	1,023.05	1,751.69	-446.51	2,018.18	2,919.25
Government Revenue	-383.87	1,034.99	1,842.42	82.72	2,745.03	4,104.37	680.48	4,604.87	6,527.07
Government Share (GS%)	20.10%	53.19%	51.18%	-18.43%	51.31%	52.36%	66.58%	52.57%	54.03%
Differences									
Rate of Return	-0.07%	-1.32%	-1.37%	0.44%	-1.37%	2.36%	-0.10%	-2.49%	-2.96%
Government Share (GS%)	-0.57%	8.30%	3.06%	8.05%	2.57%	3.15%	1.32%	3.58%	4.51%

1. Based on a Canadian-United States dollar (CND-USD) exchange rate of 0.90 and transportation costs of CND $2.00 per bbl;
e.g., USD $85/0.90 - CND $2.00 = CND $92.44

2. The Province announced new generic fiscal terms for the royalty and profit share on November 2nd:
http://www.nr.gov.nl.ca/nr/royalties/generic_orr.pdf

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Figure A1.1. Impact of new R-factor terms – DW-Inj, $85/bbl.

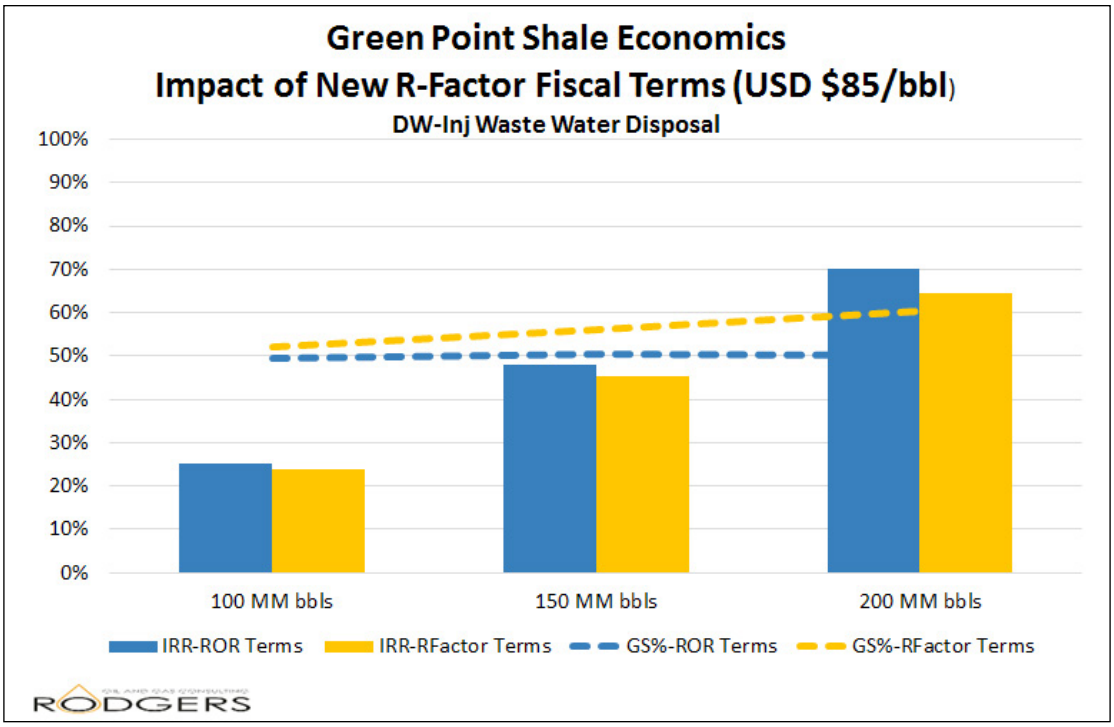

Table A1.2. Economic results for new R-factor terms – OSTT, $85/bbl.

Green Point Shale Economic Results Comparison of Generic Rate of Return-Based Terms and New R-Factor Terms Canadian Dollars - Real Values (Millions) Water Disposal - Deep Well Injection (DW-Inj)									
	Recoverable Reserves								
	100 MM bbls			150 MM bbls			200 MM bbls		
United States Dollar Price Per bbl	$50	$85	$100	$50	$85	$100	$50	$85	$100
Canadian Dollar Equivalent Price [1]	$53.56	$92.44	$109.11	$53.56	$92.44	$109.11	$53.56	$92.44	$109.11
Previous Generic ROR Fiscal Terms									
Project									
Internal Rate of Return (IRR)	3.33%	25.19%	33.81%	17.65%	48.06%	60.56%	30.77%	70.03%	86.03%
Net Cash Flow (NCF)	322.88	2,303.60	3,099.38	1,632.59	4,473.88	5,713.96	2,823.94	6,688.04	8,339.27
Net Present Value (NPV10)	-413.33	893.77	1,399.55	455.76	2,261.39	3,035.86	1,222.78	3,640.94	4,666.79
Government Revenue	375.53	2,258.52	3,118.59	1,562.07	4,528.56	5,780.81	2,875.21	6,760.09	8,435.04
Government Share (GS%)	53.77%	49.51%	51.15%	48.90%	50.30%	50.29%	50.45%	50.27%	50.29%
New Generic R-Factor Fiscal Terms [2]									
Project									
Internal Rate of Return (IRR)	2.60%	24.00%	32.19%	16.81%	45.28%	56.19%	29.67%	64.43%	77.76%
Net Cash Flow (NCF)	246.80	2,184.81	2,887.67	1,553.02	3,950.22	4,751.90	2,686.02	5,339.33	6,121.70
Net Present Value (NPV10)	-450.33	820.54	1,202.58	405.02	1,985.78	2,526.19	1,146.27	2,919.64	3,460.68
Government Revenue	451.61	2,377.31	3,333.94	1,641.64	5,052.23	6,742.87	3,013.13	8,108.80	10,652.60
Government Share (GS%)	64.66%	52.11%	53.59%	51.39%	56.12%	58.66%	52.87%	60.30%	63.51%
Differences									
Rate of Return	-0.73%	-1.19%	-1.62%	-0.84%	-2.78%	-4.37%	-1.10%	-5.60%	-8.27%
Government Share (GS%)	10.89%	2.60%	2.44%	2.49%	5.82%	8.37%	2.42%	10.03%	13.22%
1. Based on a Canadian-United States dollar (CND-USD) exchange rate of 0.90 and transportation costs of CND $2.00 per bbl; e.g., USD $85/0.90 - CND $2.00 = CND $92.44									
2. The Province announced new generic fiscal terms for the royalty and profit share on November 2nd: http://www.nr.gov.nl.ca/nr/royalties/generic_orr.pdf									
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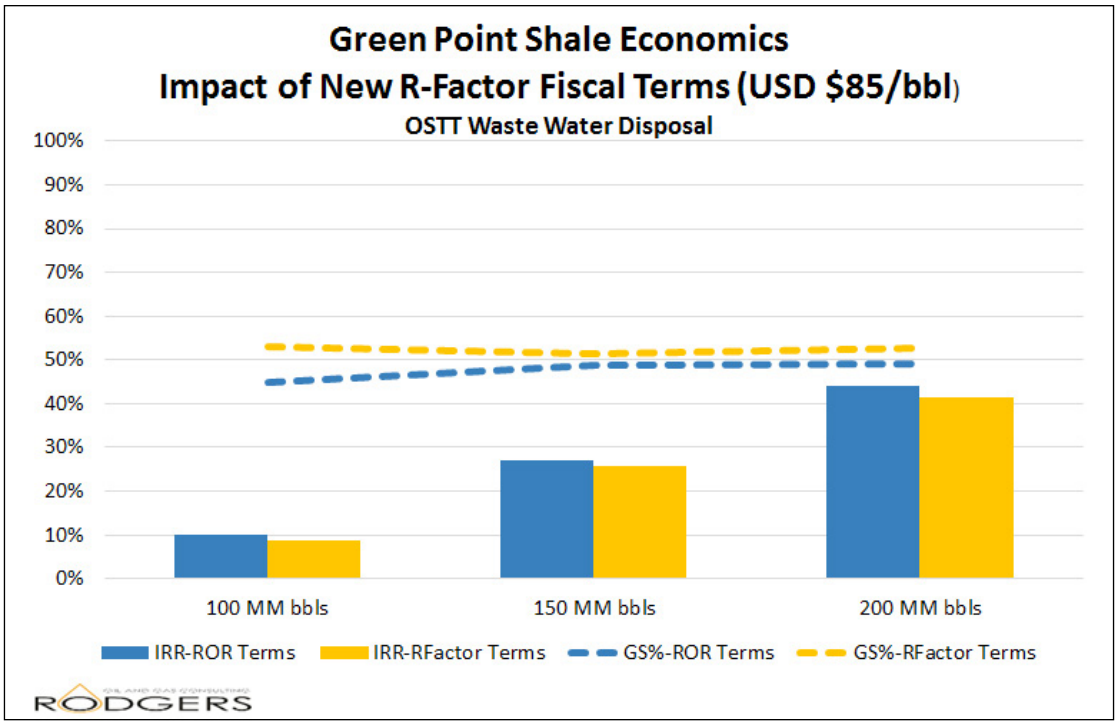
Figure A1.2. Impact of new R-factor terms – OSTT, $85/bbl.



ABOUT RODGERS OIL & GAS CONSULTING

Rodgers Oil & Gas Consulting is a consultancy firm based in Edmonton Alberta. The firm's principal, Barry Rodgers, is an economist specializing in upstream oil and gas fiscal system design and evaluation, including international and inter-jurisdictional fiscal comparison. Rodgers Oil & Gas maintains an extensive up-to-date data base containing fiscal descriptions and related fiscal and economic assessments for some 500 fiscal regimes representing over 150 countries. More information can be found at: **www.bgrodgers.com**.

Contact Information

Barry Rodgers
10409 – 134th St.
Edmonton, Alberta, Canada
Office: (780) 634-3405
Cell: (780) 905-3622
Email: barry@bgrodgers.com