Exhibit No. ___ (LWG-1)
PUBLIC VERSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Maritimes & Northeast Pipeline, L.L.C.	§ § §	Docket No. RP04-___-000

PREPARED DIRECT TESTIMONY OF
LEON W. GIESE
ON BEHALF OF
MARITIMES & NORTHEAST PIPELINE, L.L.C.

Q. 1 Please state your full name, title, and current place of employment.

A. My name is Leon W. Giese, and I am a Principal Petroleum Engineer for Duke Energy Gas Transmission Corporation ("DEGT"). DEGT's offices are located at 5400 Westheimer Court, Houston, Texas 77056.

Q. 2 What is your educational background?

A. I have a Bachelor of Science degree in Petroleum Engineering from Montana College of Mineral Science and Technology in Butte, Montana.

Q. 3 Please describe the course of your professional career and the scope of your current professional responsibilities.

A. I have been employed with DEGT and its predecessor companies, PanEnergy Corp and Panhandle Eastern Corp., since March 1976. During these 28 years, I have held various positions of responsibility, the majority of which relate directly to reservoir engineering. My duties have included analysis of the natural gas supplies connected to DEGT's corporate assets; conducting reservoir studies to estimate potential reserves; analyzing field deliverability; assessing the risk associated with the investment of capital to connect supply to DEGT's assets;

assisting with value analyses of proposed third party asset acquisitions; monitoring the performance of projects in which DEGT invests capital; and helping with other supply related issues. I have provided a more detailed description of my professional experience in Exhibit No. __ (LWG-2), which is attached to this testimony.

Q. 4 On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Maritimes & Northeast Pipeline, L.L.C. ("Maritimes").

Q. 5 Have you previously testified before the Federal Energy Regulatory Commission?

A. No, I have not.

Q. 6 What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is twofold. First, I identify and explain the gas deliverability rate for the Sable Offshore Energy Project ("SOEP") as of the end of the base period for this rate case, which is February 29, 2004, and whether or not there are likely to be any changes in that deliverability rate during the test period for this rate case, which ends November 30, 2004. Mr. William C. Penney, Jr. uses my deliverability analysis to support Maritimes' determination of the billing determinants that underlie the mainline rates proposed by Maritimes in this proceeding. Second, I identify and explain the expected supply life of the natural gas reserves and resources in the offshore Nova Scotia basin. Mr. Edward H. Feinstein uses my analysis of the expected supply life of the gas reserves and resources in the offshore Nova Scotia basin in connection with his assessment of the mainline depreciation rate proposed by Maritimes in this proceeding.

Q. 7 What statements, schedules, or exhibits are you sponsoring in conjunction with your direct testimony?

A. In addition to this testimony, Exhibit No. __ (LWG-1), I am sponsoring Exhibit Nos. __ (LWG-2) through (LWG-15).

Q. 8 Were these exhibits prepared by you or under your direction or supervision?

A. Yes, each of these exhibits was prepared by me or under my direction and supervision.

SOEP DELIVERABILITY

Q. 9 Did you analyze the deliverability rate of the SOEP fields as of the end of the base period, which is February 29, 2004?

A. Yes, I did.

Q. 10 Please explain the results of your analysis.

A. My analysis of the SOEP fields shows that collectively they were producing approximately 471,000 dekatherms per day ("Dth/d") as of February 29, 2004.

Q. 11 Is this rate based on the actual production measured at the platforms?

A. No. I have factored into this rate shrinkage at the Goldboro processing plant and fuel for the gathering infrastructure such that the 471,000 Dth/d reflects the quantity of gas measured at the interconnection between the processing plant and the pipeline facilities owned by Maritimes' Canadian pipeline affiliate, Maritimes & Northeast Pipeline Limited Partnership ("Maritimes-Canada"). In addition, I have converted the volumetric production rate into dekatherms using a Btu factor of 1060, which is the average Btu content of a cubic foot of the gas measured by Maritimes-Canada at its interconnection with the Goldboro processing plant.

Q. 12 Is this production rate the same as the deliverability rate for the SOEP fields?

A. Yes. Deliverability is the physical capability to produce without harming the long-term productivity of the well or reservoir, and since the SOEP fields are currently producing at their maximum capacity, the production of the SOEP fields equates to the deliverability of those fields.

Q. 13 In your analysis, which fields did you consider to be within the SOEP?

A. The original SOEP proposal, as described in the development plan filed by the sponsors of the SOEP with the Canada-Nova Scotia Offshore Petroleum Board ("CNSOPB"), reflected the proposed development of six fields. These fields are known as Venture, Thebaud, North Triumph, Alma, South Venture and Glenelg. Four of these six fields, Venture, Thebaud, North Triumph and Alma, are currently producing commercial quantities of gas, and those are the only fields that I considered in my deliverability rate analysis as within the SOEP. I have attached a map of the offshore Nova Scotia basin, which includes the location of the six fields originally proposed to be a part of the SOEP, in Exhibit No. __ (LWG-3).

Q. 14 Why did you analyze only these four SOEP fields?

A. The purpose of my deliverability analysis is to determine the production rate at which the SOEP properties were flowing gas to Maritimes-Canada as of February 29, 2004, and these four SOEP fields were the only fields in the offshore Nova Scotia basin producing commercially at that time.

Q. 15 What production data did you use to determine the SOEP deliverability rate as of February 29, 2004?

A. I used the actual production data from the currently producing wells in the SOEP fields, as reported by the SOEP producers to the CNSOPB. The CNSOPB maintains this data, on a well-by-well basis for each field, as a monthly record of the volumes that are produced from each reporting SOEP well. The CNSOPB identifies this data as the wellhead volume for each of the reported wells. My analysis of the SOEP fields as of the end of the base period is based on the February 2004 volumes reported to the CNSOPB by the producers for the producing wells in the four SOEP fields of Venture, Thebaud, North Triumph, and Alma. I have attached a table showing the February 2004 volumes by well for those four SOEP fields in Exhibit No. __ (LWG-4).

Q. 16 What is the CNSOPB?

A. The CNSOPB is an independent joint agency of the governments of Canada and Nova Scotia responsible for the regulation of petroleum affairs and safe practices offshore Nova Scotia. The CNSOPB's principal responsibilities, as stated on their website, include (i) ensuring the safe conduct of offshore operations, (ii) protection of the environment during offshore petroleum activities, (iii) management of offshore oil and gas resources, (iv) review of industrial benefits and employment opportunities, (v) issuance of licenses for offshore exploration and development, and (vi) resource evaluation, data collection and distribution.

Q. 17 Did you analyze whether the deliverability rate for the four producing SOEP fields would change during Maritimes' test period, which is the nine-month period ending November 30, 2004?

A. Yes, I did.

Q. 18 What were the results of your analysis?

A. My analysis shows that the deliverability rate for the SOEP fields will decline to an average daily quantity of 405,000 Dth for the month of November 2004. This quantity reflects shrinkage at the Goldboro processing plant, fuel for the gathering infrastructure, and a Btu conversion factor of 1060. I have attached a graph showing the average monthly per day delivery rate from February 2004 through the test period in Exhibit No. __ (LWG-5).

Q. 19 Are there any fields other than the four producing SOEP fields that are capable of flowing gas to Maritimes during the test period?

A. No, there are no other currently producing fields or potential fields that are capable of flowing gas to Maritimes during that time period.

Q. 20 What is the basis for this conclusion?

A. The only development plan currently on file with the CNSOPB is the development plan for the SOEP. This plan reflects only two additional future field developments, which are the South Venture field and the Glenelg field. Based on public pronouncements from the SOEP producers regarding the South Venture field, the field is being prepared to commence production in the beginning of 2005. In addition, due to poor findings from a recent development well in the field, Shell Canada Resources Limited ("Shell Canada") has publicly stated that the Glenelg field is uneconomical as a stand-alone project, and development of that field is no longer part of the SOEP development plan. Thus, neither the South Venture field nor the Glenelg field is expected to be placed into commercial production by the end of the test period.

Q. 21 What process did you use to identify the deliverability rate for the four currently producing SOEP fields as of the end of the test period?

A. I used a rate-time analysis to project the current decline in production for those SOEP fields to the end of the test period.

Q. 22 Please describe your rate-time analysis.

A. A rate-time analysis translates the historical production rate of existing wells in a field into a current annual rate of decline per well, which can then be aggregated into an overall field annual rate of decline and projected into the future to the economic limit of the estimated field reserves.

For the test period, my rate-time analysis focuses on the historical production of the existing wells in the four currently producing SOEP fields, and determining a current annual rate of decline of this production for each well. I have plotted, on a well-by-well basis, the historical monthly production data, from the date each well commenced production in commercial quantities until the date of the most recently available production data, which is April 2004, and analyzed the production decline of each well. I then extrapolated the annual production decline (or trend) for each well and projected that decline into the future to an economic limit, resulting in a projected production profile for each well. Finally, I aggregated the projected production profiles for each well to a field basis and total project basis for analysis and reporting.

As I stated earlier, for the four currently producing SOEP fields, I developed a decline trend for the project based on the actual production data available from the CNSOPB for the wells in those SOEP fields. Starting with the average daily deliverability rate of 456,000 Dth/d for the SOEP in April 2004, the last month of actual production data available from the CNSOPB at the time of my analysis, I projected the SOEP decline trend through November 2004. As depicted in Exhibit No. __ (LWG-5), based on the historical decline trend for the four producing SOEP fields, the average daily deliverability rate for the SOEP will decline to an estimated 405,000 Dth/d for November 2004.

Q. 23 Is the rate-time analysis you used commonly used to estimate future deliverability rates for a particular gas supply source?

A. Yes, the rate-time analysis I used is one of the standard analyses used in the natural gas industry to estimate future deliverability rates on a well, field, area or basin basis.

Q. 24 Why did you not use one of the other standard analyses?

A. The other standard analyses for estimating deliverability rates of natural gas require pressure data as an input, and there is presently no publicly available source for such pressure data.

OFFSHORE NOVA SCOTIA BASIN SUPPLY LIFE

Q. 25 Have you analyzed the supply life for the offshore Nova Scotia basin beyond the test period for this case?

A. Yes, I have conducted a study of the supply life for the offshore Nova Scotia basin, which extends beyond the test period.

Q. 26 What were the results of your study?

A. Based on my study, which is attached in Exhibit No. __ (LWG-6), the estimated production rate of the fields in the offshore Nova Scotia basin will have declined to approximately 210,000 Dth/d during 2027 under my P50 case.

Q. 27 What is the significance of the basin production rate declining to 210,000 Dth/d?

A. As explained in more detail in the prepared direct testimony of Mr. Feinstein, 210,000 Dth/d of offshore Nova Scotia production, once the Canadian consumption and fuel use is factored in, is the point at which the Maritimes system would begin operating at a loss because the cost of operating its pipeline facilities would exceed the revenue stream to be generated from the available gas supply from the offshore Nova Scotia basin.

Q. 28 Please summarize the process you used to conduct your supply study.

A. First, I developed a list of all the fields that either currently produce gas supply or could in the future potentially produce gas supply in the offshore Nova Scotia basin from a comprehensive list of significant and commercial discoveries in the basin reported by the CNSOPB, to which I will refer to as "discovered" fields, a list of "undiscovered" fields in the basin reported by the Canadian Gas Potential Committee, and information contained in the EnCana (formerly PanCanadian Energy) development plan application for the Deep Panuke field previously on file with the CNSOPB (EnCana has withdrawn this application).

Second, in order to determine the total amount of reserves and resources to be potentially produced over the life of the basin, I identified gas-in-place estimates for the selected fields, as reported by the CNSOPB for the SOEP fields and other discovered fields, the Canadian Gas Potential Committee for the undiscovered fields, and EnCana in its development plan application for the Deep Panuke field.

Simply because reserves have been discovered does not, however, necessarily mean that the reserves are economic to produce. As the third step in my study, I employed a rate-time analysis to create three comparison production profiles based on a 90 percent (the "P90 case"), 50 percent (the "P50 case"), and 10 percent (the "P10 case") likelihood that development of the various potential reserves and resources in the offshore Nova Scotia basin, and connection of those reserves and resources to Maritimes, would occur, assuming certain projected initial production dates for the fields not yet in production, the continuation of the historical decline trend for the basin, and that wells would continue producing until they reached their economic limit. As part of this analysis, I factored into the CNSOPB's and Canadian Gas Potential Committee's gas-in-place estimates the CNSOPB's anticipated recovery percentage of gas-in-place reserves, and an adjustment to compensate for the actual production experienced at the currently producing SOEP fields, to arrive at estimates of recoverable reserves and resources. For the Deep Panuke field, I only factored into EnCana's development plan application gas-in-place estimate the CNSOPB's anticipated recovery percentage to arrive at an estimate of recoverable reserves for that field. Consistent with industry standards, I adopted the P50 case I developed as the most likely scenario of the remaining offshore Nova Scotia potential gas supply and rate at which that supply will be produced.

Q. 29 What is the theory behind the estimation of a P10, P50 and P90 case?

A. The P10, P50 and P90 values are derivatives of a Monte Carlo Simulation risk analysis. The purpose of a Monte Carlo Simulation risk analysis is to provide an estimate of an unknown resource with a range of values rather than a single value. The simulation can be described as a cumulative probability distribution. The simulation often describes distributions by specifying two or three percentiles. The P90, P50 and P10 cases are the common reference points used to describe a resulting probability distribution. The P10 case refers to the 10th percentile, and is the value of the resource corresponding to the 0.10 on the cumulative-probability axis. With a P90 case, there is a 90 percent chance that the indicated value will be equaled or exceeded. Of particular interest, however, is the P50 case, where there is a 50 percent chance that the indicated value will be equaled or exceeded. The P50 case is considered to be the most likely prediction scenario. Since I have adopted my P50 case for the purposes of my study, I will only describe the assumptions underlying my P50 case in this testimony. Nevertheless, I have provided a full description of the process used to create, and the results of, my P90 and P10 cases in my Supply Life Study of the offshore Nova Scotia Basin, which I have attached to this testimony as Exhibit No. __ (LWG-6).

Q. 30 I have noticed that you have been using the term "resources." Are resources the same thing as reserves?

A. No. Reserves are volumes of hydrocarbons that have been proven to exist by drilling, testing and interpretation of all available data. Resources are volumes of hydrocarbons that are expected to exist based on seismic or supply modeling, but have not been drilled and tested.

<u>Estimation of Offshore Nova Scotia Basin Gas-in-Place Reserves and Resources</u>

Q. 31 Which fields did you consider in your analysis of the potential reserves and resources in the offshore Nova Scotia basin?

A. First, I considered the fields in the basin that are currently producing or that are part of a current development plan on file with the CNSOPB, which are the five SOEP fields of Venture, Thebaud, North Triumph, Alma, and South Venture. I will refer to these five fields collectively as the "SOEP fields." Second, I considered the remaining discovered fields reported by the CNSOPB, which are the discovered fields that have not yet begun production, and the undiscovered fields reported by the Canadian Gas Potential Committee that, while their development is very uncertain and speculative at this time, may be developed in the future. I will refer to these discovered and undiscovered fields collectively as "speculative fields." Third, I considered the Deep Panuke field because, based on EnCana's public statements near the end of 2003 when it withdrew its plan, it appears reasonably likely that EnCana will develop Deep Panuke near the end of this decade.

Q. 32 How did you determine the potential reserves of the SOEP fields?

A. I used the gas-in-place estimates reported by the CNSOPB for the four currently producing SOEP fields, Venture, Thebaud, North Triumph and Alma, as well as for the South Venture field.

Q. 33 Besides the five SOEP fields you have identified, are there any other fields that make up the SOEP for the purposes of your analysis?

A. No. As I noted earlier, the original SOEP development plan on file with the CNSOPB included six fields. The sixth field, Glenelg, is now considered uneconomical as a stand-alone project, and the SOEP consortium has placed the development of this field on hold. Since Glenelg is no longer part of the SOEP development plan, I do not consider Glenelg to be a part of the SOEP. I have, nevertheless, included the Glenelg field in my analysis of the speculative fields containing potential reserves in the offshore Nova Scotia basin.

Q. 34 Based on your analysis, what do you estimate to be the total potential gas-in-place reserves for the SOEP fields?

A. 5.2 trillion cubic feet ("Tcf"). I have provided a table of the estimated gas-in-place reserves for each SOEP field in Schedule No. 1 of Exhibit No. __ (LWG-8).

Q. 35 How did you determine the potential reserves and resources for the speculative fields?

A. I used the gas-in-place estimates reported by the CNSOPB for the discovered fields that have not yet begun production and the gas-in-place estimates reported by the Canadian Gas Potential Committee for the undiscovered fields. I have provided the CNSOPB's list of discovered fields that have not yet begun production, and its estimate of the corresponding P50 case gas-in-place reserves for those fields, in Schedule No. 2 of Exhibit No. __ (LWG-8), and the Canadian Gas Potential Committee's list of undiscovered fields, and its estimate of the corresponding P50 case gas-in-place resources for those fields, in Schedule No. 4 of Exhibit No. __ (LWG-8).

Q. 36 What is a "discovered" field?

A. I use the term discovered field to refer to those fields that the CNSOPB defines as containing either commercial discoveries or a significant discovery. The CNSOPB defines "commercial discoveries" as a discovery of petroleum that has been demonstrated to contain petroleum reserves that justify the investment of capital and effort to bring the discovery to production. The CNSOPB defines a "significant discovery" as a discovery in which the first well on a geological feature demonstrates by flow testing the existence of hydrocarbons in that feature and, taking into consideration geological and engineering factors, suggests the existence of an accumulation of hydrocarbons that has the potential for sustained production. As such, the term discovered field refers to a field that either is currently producing or that has been penetrated by an exploration well, confirming the existence of a hydrocarbon bearing reservoir containing identifiable gas reserves, but that has not yet been developed and produced.

Q. 37 You stated that you identified gas-in-place estimates for the undiscovered fields by using estimates reported by the Canadian Gas Potential Committee. What is the Canadian Gas Potential Committee?

A. The Canadian Gas Potential Committee is a volunteer group of industry and government geoscientists employed by companies currently active in various exploration plays in Canada, including the offshore Nova Scotia basin, to provide an independent evaluation of potential gas resources based on industry experience. The Committee utilizes geological judgment and extensive peer reviews, along with statistical analyses, to make its assessment of future natural gas resources. The Committee has conducted the most comprehensive study of Canada's undiscovered natural gas resources to date, and is deemed by the industry to have the most scientifically-based and accurate estimate of undiscovered resources in the offshore Nova Scotia basin.

Q. 38 What types of fields does the Canadian Gas Potential Committee include in the term "undiscovered" field?

A. An undiscovered field, as determined by the Canadian Gas Potential Committee, is a field that could potentially exist based on its supply modeling study, but that has not been penetrated by an actual well.

Q. 39 How did the Canadian Gas Potential Committee estimate the potential gas-in-place resources of the undiscovered fields?

A. The Canadian Gas Potential Committee's study determined the potential gas resources for the undiscovered fields on a field size by field size basis. The study applied the Arps-Roberts Method based on the P50 reserve estimates of the CNSOPB as well as other characteristics of the discovered fields to determine the amount of potential resources for the undiscovered fields.

Q. 40 Please describe the Arps-Roberts Method.

A. The Arps-Roberts Method is a discovery process methodology. The methodology, as applied in the Canadian Gas Potential Committee study, predicts the number and size of undiscovered fields based on the ratio of the area of the discovered fields reported by the CNSOPB compared to the area of the basin and the number of exploratory wells that have been drilled. The discovered fields are assigned to class sizes based on the level of estimated reserves. The exponential equation developed by Messrs. Arps and Roberts is as follows:

$$F_K(\infty) = \frac{F_K(w)}{\left(1 - e^{\frac{-CAw}{B}}\right)}$$

Where:

$F_K(\infty)$ =	ultimate number of fields in size class K.
$F_K(w)$ =	cumulative number of discoveries recognized in size class K after drilling w wells.
B =	area of the study area.
A =	average areal extent of the fields in size class K.
w =	cumulative number of exploratory wells drilled in the study area.
C =	efficiency of exploration.

Q. 41 How will a revision to the input data used in an Arps-Roberts analysis affect the results of that analysis?

A. It can be observed from the above equation that the number of fields and class size are controlling variables in the methodology. Thus, a revision in the underlying proven reserves will be reflected in a like revision to the estimated resources of the undiscovered fields.

Q. 42 Have any of the producers in the offshore Nova Scotia basin released their estimates of the total gas supply available from the speculative fields in the basin on a per field basis?

A. No, they have not. The only publicly available data on estimated reserves and resources in the offshore Nova Scotia basin speculative fields on a per field basis is that provided by the CNSOPB for the discovered fields, the Canadian Gas Potential Committee for the undiscovered fields, and EnCana for the Deep Panuke field. Due to the proprietary nature of such exploration information, there is currently no publicly available information regarding the location of such undiscovered fields or the geological composition of the reservoirs within those fields.

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Q. 44 How did you determine the potential reserves for the Deep Panuke field?

A. I relied on the gas-in-place estimate reported by EnCana in its development plan application for the field filed with the CNSOPB.

Q. 45 Based on this data, what is estimated total gas-in-place reserves for the Deep Panuke field?

A. 1.1 Tcf, as shown in Schedule No. 2 of Exhibit No. __ (LWG-8).

Q. 46 Having identified the total gas-in-place reserves for the SOEP, Deep Panuke, and speculative fields, did you assume for the purposes of your study that all of these estimated gas-in-place reserves and resources would be produced?

A. No. Simply because reserves have been discovered does not necessarily mean that the reserves will be developed or be recoverable.

Q. 47 Please explain what you mean by "recoverable" reserves.

A. By recoverable I mean the portion of the gas in a reservoir, or gas-in-place, that can actually be removed or produced using currently available techniques and technology.

<u>Estimation of Recoverable Reserves and Resources</u>

Q. 48 How did you estimate the portion of your gas-in-place estimates for the SOEP fields that is recoverable?

A. I used a rate-time analysis to extrapolate an annual production decline trend for each field based on the actual monthly gas production from the wells in three of the currently producing SOEP fields, Venture, Thebaud and North Triumph. By projecting those decline trends to the economic limit of those fields, and applying the resulting average decline trend to the Alma and South Venture fields, I determined the total amount of recoverable reserves that each of the SOEP fields would ultimately produce. The resulting recoverable reserve amounts for each of the SOEP fields are shown in Schedule No. 1 of Exhibit No. __ (LWG-8).

Q. 49 As part of the explanation of your rate-time analysis, you stated that you projected the production decline for each well to its economic limit. What is the economic limit of a well?

A. The economic limit of a well is the point at which the monthly costs for producing the remaining reserves exceed the projected revenue stream for production of those reserves. In other words, even though minimal amounts of recoverable reserves may still remain in the respective fields, for all practical purposes the producible reserves from each field will be depleted at the well's economic limit.

For my analysis, the economic limit of a particular well is derived by holding constant a set of underlying assumptions based on current economic realities, even though one or more of these assumptions could fluctuate over time. Specifically, I derived the economic limit of a particular well in the offshore Nova Scotia basin by comparing expected monthly operating costs per well of $215,000 (US) and an expected total natural gas transportation cost of $1.5594 (US) per Dth collectively for the Maritimes and Maritimes-Canada systems to the expected monthly revenue stream, using an estimated gas price of $5.00 (US) per Dth and an estimated oil price of $32.00 (US) per barrel as a proxy for the price of condensate, which are based on a 10-year average of prices as reported in the Energy Information Administration's ("EIA") Annual Energy Outlook for 2004.

Since I have no record of condensate production for the four currently producing SOEP fields, I used the CNSOPB's projected condensate yield for each developed field, including the SOEP fields, to make this calculation. Since the Canadian Gas Potential Committee does not provide an estimate of condensate yields for the undiscovered fields, for the undiscovered fields I used the average of the CNSOPB's projected condensate yield for each of the discovered fields. Based on these underlying economic assumptions, the average discovered well reaches its economic limit at approximately 1620 Dth/d. The calculation of the economic limit for an average well is shown in Exhibit No. __ (LWG-7).

Q. 50 You mentioned that your P10, P50, and P90 case estimates are derived from a Monte Carlo Simulation risk analysis. Did the CNSOPB perform a Monte Carlo Simulation risk analysis to develop a P90, a P50, and a P10 recoverable reserve estimate for the currently producing SOEP fields?

A. Yes, it did.

Q. 51 Did you compare the P50 recoverable reserve estimates of the CNSOPB for the SOEP fields to your recoverable reserve estimates, which are based on actual production performance data for those fields?

A. Yes, I did.

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Q. 76 Based on your experience in estimating the reserve life of natural gas projects in the Gulf of Mexico, do you see any similarities between the development of those projects and the development of projects within the offshore Nova Scotia basin?

A. No, the development of the natural gas projects in the two regions has followed very different paths. Fields in the Gulf of Mexico containing similar geological structures to those in the offshore Nova Scotia basin have experienced a much shorter delay between initial discoveries and development, due in part to their closer proximity to the shoreline and the vast offshore and onshore gathering and transmission infrastructure. Exploration in the Gulf of Mexico commenced in 1938 as an extension from onshore production into the shallow waters off the coast, with first production starting in 1947 approximately 10 miles from the Louisiana coast in Ship Shoal Block 32. In contrast, Nova Scotia's offshore exploration did not begin until 1967 with the first Sable Island well (C-67), and the first gas was not produced until December 1999, which was from the SOEP development that lies approximately 125 miles offshore.

This greater delay between discovery and production in the offshore Nova Scotia basin is due in part to the higher cost of getting discovered gas to shore for that basin. In the Gulf of Mexico, gas pipeline infrastructure has been built out to transport volumes back to the shore as new discoveries are made. As a result, new fields have ample existing infrastructure in close proximity to tie into for delivery to shore, which has made it economically feasible for producers to produce gas from fields in over 7,000 feet of water. In contrast, development of the offshore Nova Scotia basin has not extended from onshore and progressed further and further offshore, and thus the basin has not been able to benefit from the ability of simply extending existing infrastructure as new discoveries are made. Instead, given that initial development was approximately 125 miles offshore and that the cost of constructing new pipelines to shore is relatively expensive, developing production from new fields has been limited to those fields that can economically connect to the existing SOEP gathering infrastructure.

The result is that while to date over 40,000 wells have been drilled in the Gulf of Mexico with an average of 1000 to 1200 wells drilled per year over the last several years, there have been only approximately 200 wells drilled in the offshore Nova Scotia basin.

Q. 77 What do the differences between the two basins tell you about the likely development of the offshore Nova Scotia basin?

A. The differences in the basins make it unlikely that another pipeline from the shore will be built in the offshore Nova Scotia basin unless an extremely large potential resource package is discovered or a cluster of large potential resource packages are discovered in close proximity to one another to allow joint development. As capacity on SOEP's offshore line becomes available, some of the large discoveries on the shelf may be developed, if they are within reasonable distance to the existing SOEP gathering infrastructure. However, as evident from EnCana's delay of its development of the Deep Panuke field and its reported negotiations with the SOEP producers regarding use of the SOEP gathering infrastructure, even a field with 1 Tcf of potential reserves is apparently not enough to justify the cost of constructing a new pipeline from a new field to the shoreline. Thus, while exploration, discoveries and field development have continued to extend further from the coast and into deeper waters in the Gulf of Mexico, development of the offshore Nova Scotia basin has remained and is likely to continue to remain concentrated around the initially developed SOEP fields.

<u>Projected Production Profiles</u>

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Q. 82 Once you had determined the total amount of recoverable reserves and resources that remain to be potentially produced from offshore Nova Scotia basin fields in your P50 case, how did you determine what the ultimate life of those reserves and resources would be?

A. I created a production profile of the produced reserves and remaining recoverable reserves and resources for the P50 case fields based on a rate-time analysis. As I described earlier in my testimony, a rate-time analysis involves extrapolating a decline trend for a project based on historical production data, and then applying that trend on a prospective basis until depletion of the identified reserves and resources.

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Q. 86 Based on the P50 case decline trends you used for the SOEP fields, the speculative fields, and the Deep Panuke field, what do you estimate to be the supply life of the offshore Nova Scotia basin recoverable reserves and resources?

A. As shown in Exhibit No. __ (LWG-10), I estimate, based on my P50 case, that the production rate of the fields in the offshore Nova Scotia basin will have declined to approximately 210,000 Dth/d during the year 2027. As I stated earlier in my testimony, this production rate is the point at which Mr. Feinstein has determined that the Maritimes system would begin operating at a loss because the cost of operating its pipeline facilities would exceed the revenue stream to be generated from the available gas supply from the offshore Nova Scotia basin, and thus is the effective depletion point of the offshore Nova Scotia reserves and resources as far as Maritimes is concerned.

Q. 87 Does this conclude your prepared direct testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Maritimes & Northeast Pipeline, L.L.C.	§ § §	Docket No. RP04-

AFFIDAVIT OF LEON W. GIESE

LEON W. GIESE, being first duly sworn, on oath states that he is the witness whose Prepared Direct Testimony is filed herein; that, if asked the questions which appear in the text of aforesaid Prepared Direct Testimony, affiant would give the answers that are herein set forth; and that affiant adopts the aforesaid Prepared Direct Testimony as his sworn, direct testimony in this proceeding.

Leon W. Giese

LEON W. GIESE

SUBSCRIBED AND SWORN TO before me, a Notary Public in and for the State of Texas, County of Harris, this 22nd day of June, 2004.

Barbara A. Hulsey

Notary Public

BARBARA A. HULSEY
Notary Public, State of Texas
My Commission Expires
OCTOBER 2, 2004

NOTARY PUBLIC STATE OF TEXAS

My commission expires: 10-2-04

Leon W Giese

Duke Energy Gas Transmission Corporation
5400 Westheimer Court
Houston, TX 77056

PRINCIPAL PETROLEUM ENGINEER

Twenty-seven years' experience in the energy industry with increasing responsibilities and successful record of achievement. Current specialty: Working responsibility and knowledge of the offshore Gulf Coast, offshore Nova Scotia, Northern Louisiana, and Mid-Texas; ability to adapt and work projects in any geographic area; creative development of technical computer software.

EDUCATION

June 1976 BS Petroleum Engineering, Montana Collage of Mineral Science and Technology, Butte, Montana.

EXPERIENCE AND ACCOMPLISHMENTS

1991 – Present **PanEnergy/Duke Energy - Corporate Reserves**

- Analyze natural gas supplies connected to corporate assets to identify future supply requirements needed to maximize available pipeline throughput capacity.
- Conduct reservoir studies to estimate potential reserves and deliverability and to identify the risk associated with investment of capital to connect the supply to corporate assets.
- Monitor the performance of projects in which the corporation invests capital.
- Develop and maintain computer software to assist Corporate Reserves in the analysis of various projects and opportunities.
- Assist with the value analysis associated with proposed third party asset acquisitions.
- Compile and analyze U.S. gas supply forecasts. Prepare and present presentations to industry audiences.
- Create and maintain production databases for volume connected to various corporate assets.

1983 – 1991 **Panhandle Eastern Pipe Line - Regulations & Litigation**

- Monitor all proposed state legislation in Kansas, Oklahoma and Texas to identify legislation that could potentially have an impact on the corporation. Alert the proper departmental representative of the potential impact and assist them in the development of a plan to support or resist legislative action.
- Monitor all applications and proposed rulemakings before the state oil & gas regulatory agencies (Kansas, Oklahoma and Texas) and analyze potential impact on the corporation. Testify at regulatory hearings to represent the corporation's position on issues.
- Lobby oil & gas regulatory agencies to make corporate views known.

1981 – 1983 **Panhandle Eastern Pipe Line - Technical Applications**

- Develop technical software for use within the Gas Supply Department.
  - Dwight's data retrieval with detailed and summary outputs.
  - Well test module for inclusion in a pipeline throughput simulator.
  - Deliverability forecasting programs, with contractual constraint and obligations considered.
  - Graphics programs to assist with decline curve and well test analysis, and mapping applications.

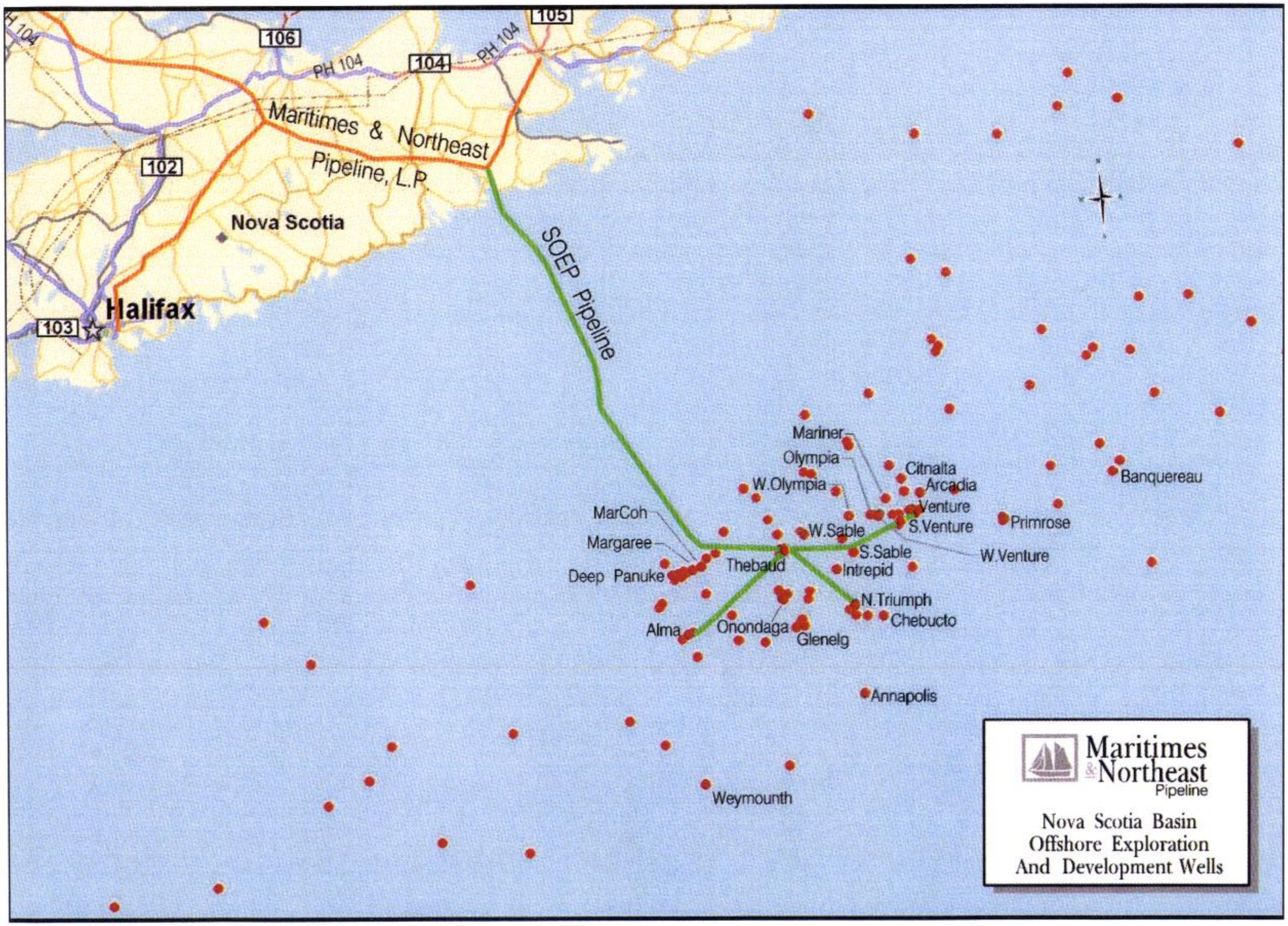
1976 – 1981 **Panhandle Eastern Pipe Line - Reservoir Engineering**

- Acquire and compile technical well information for all wells connected to Panhandle Eastern gathering assets and conduct pipeline flow simulations to help identify pipeline flow constraints and compression needs.
- Perform reserve evaluations for individual proposed well connections, as well as large development projects, in order to advise the corporation of the pipeline and capital requirements for a connection.
- Estimated the reserves associated with wells connected to systems in my area of responsibility for inclusion in the annual FERC Form 15 filings.
- Testify before FERC to justify major pipeline expansions.

PROFESSIONAL AFFILIATIONS

- Society of Petroleum Engineers
- American Association of Petroleum Geologists
- Houston Geologic Library
- Society of Exploration Geophysicists

Exhibit No. __ (LWG-3)
PUBLIC VERSION



Offshore Nova Scotia Basin
Production at the End of the Base Period

	February 2004 Production (Mcf)	February 2004 Production (Dth)
Alma 1	2,246,479	2,289,946
Alma 2	1,465,678	1,494,037
North Triumph 1	1,388,226	1,415,087
North Triumph 2	765,153	779,958
Thebaud 1	1,114,813	1,136,384
Thebaud 2	1,031,722	1,051,684
Thebaud 3	1,407,540	1,434,775
Thebaud 5	215,830	220,006
Thebaud 6	394,928	402,570
Venture 1	1,262,921	1,287,358
Venture 2	876	893
Venture 3	577,392	588,564
Venture 4	496,059	505,657
Venture 5	0	0
Venture 6	1,025,315	1,045,154
Monthly Total	*13,392,933*	*13,652,072*
Daily Average	**461,825**	**470,761**

Exhibit No. __ (LWG-5)
PUBLIC VERSION

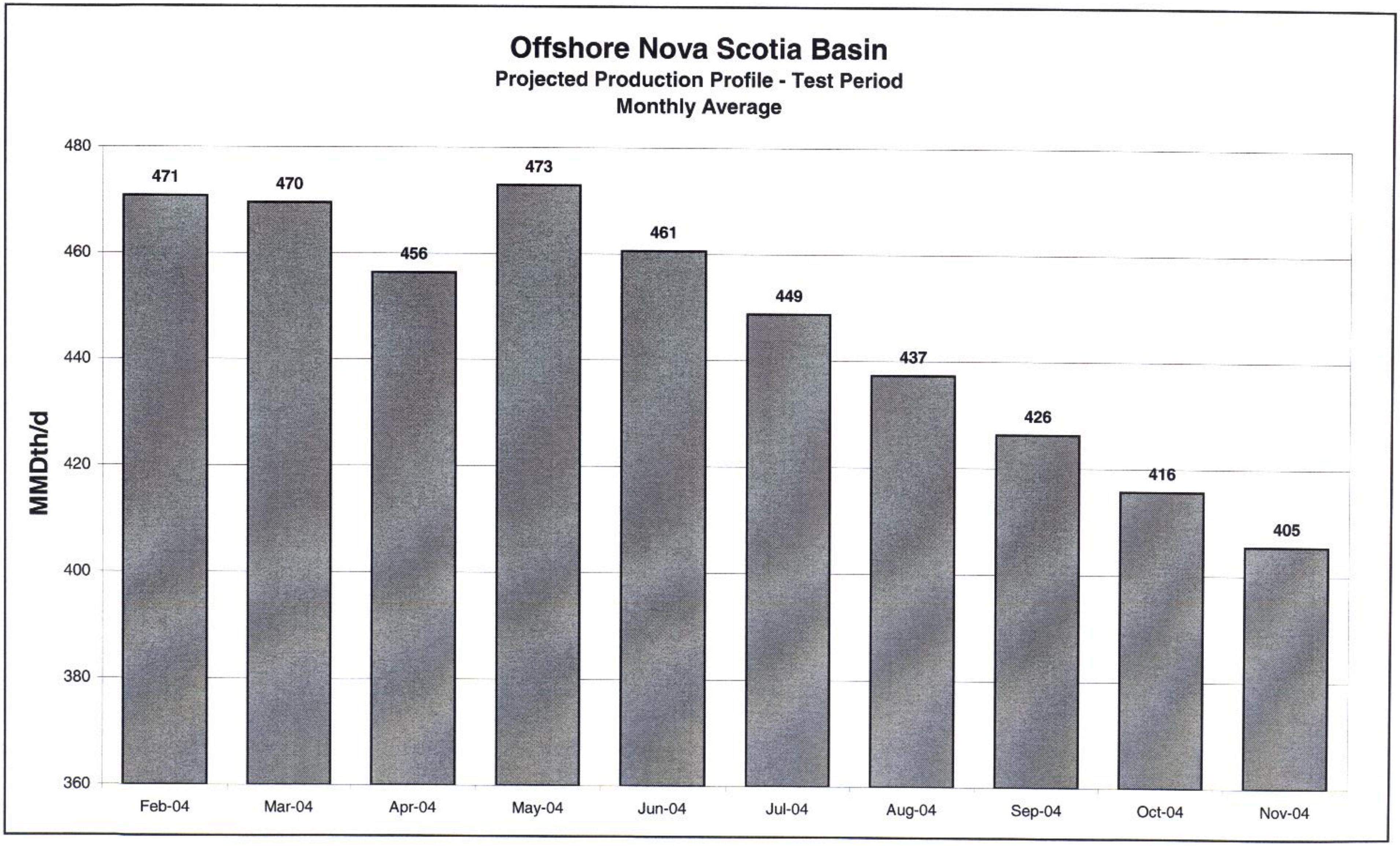


Exhibit No. __ (LWG-6)
PUBLIC VERSION

SUPPLY LIFE STUDY

OFFSHORE NOVA SCOTIA BASIN

A Study Prepared for
Maritimes & Northeast Pipeline, L.L.C.
by

Leon W. Giese

Prepared: **June 2004**

TABLE OF CONTENTS

INTRODUCTION

Maritimes & Northeast Pipeline, L.L.C. ("Maritimes") requested that I, Mr. Leon W. Giese, a Principal Petroleum Engineer for Duke Energy Gas Transmission Corporation, prepare a study of the future gas supply from the Scotian Shelf area offshore of Nova Scotia ("offshore Nova Scotia basin"). The study was limited to the offshore area that falls under the jurisdiction of the Canada-Nova Scotia Offshore Petroleum Board ("CNSOPB"), as illustrated on Map-1.

The primary objective of the study was to assess the expected supply life of the offshore Nova Scotia basin gas resources.

The study is based on my own, independent analysis of existing publicly available potential reserve and resource estimates and other documents relating to the ultimate gas potential of the various offshore Nova Scotia geological plays and of the offshore Nova Scotia basin as a whole.

SUMMARY

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BACKGROUND

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METHODOLOGY

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GAS SUPPLY FORECASTS

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FORECASTED PRODUCTION PROFILES

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CONCLUSIONS

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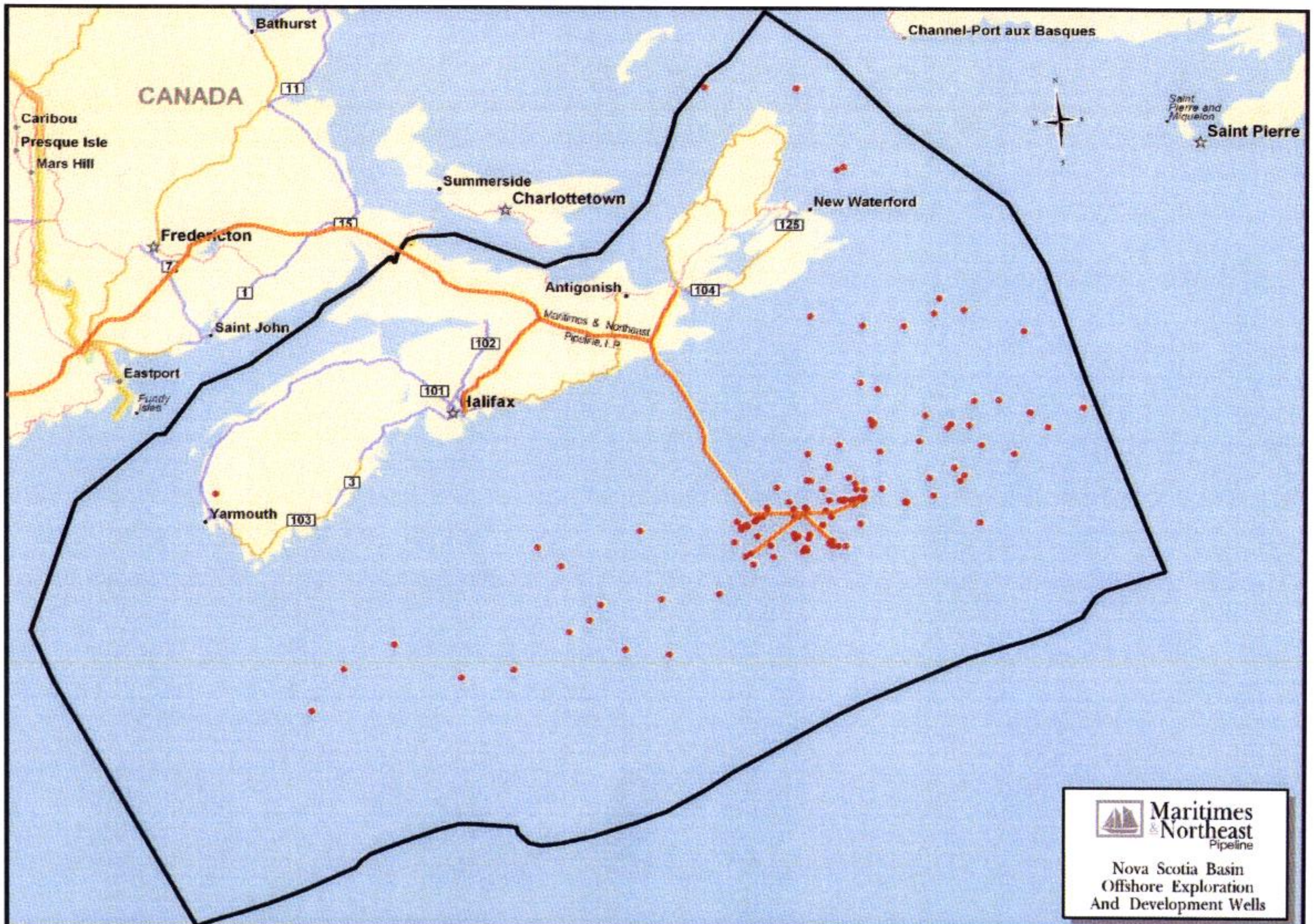
OF THE COMMISSION'S REGULATIONS

MAPS

Map-1
Offshore Nova Scotia Basin



TABLES

TABLE 1

Offshore Nova Scotia Basin Estimated Reserves and Resources
Leon Giese P50 Case

Privileged Information Redacted
Pursuant to Section 388.112
of the Commission's Regulations

TABLE 2

Offshore Nova Scotia Basin Estimated Reserves and Resources

Leon Giese P90 Case

Privileged Information Redacted
Pursuant to Section 388.112
of the Commission's Regulations

TABLE 3

Offshore Nova Scotia Basin Estimated Reserves and Resources
Leon Giese P10 Case

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of the Commission's Regulations

FIGURES

Figure 1
Offshore Novia Scotia Basin
Projected Production Profile - P50 Case

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of the Commission's Regulations

Figure 2
Offshore Novia Scotia Basin
Projected Production Profile - P90 Case

Privileged Information Redacted
Pursuant to Section 388.112
of the Commission's Regulations

Figure 3
Offshore Novia Scotia Basin
Projected Production Profile - P10 Case

Privileged Information Redacted
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of the Commission's Regulations

Figure 4

Nova Sotia Average Sandstone Type Well

**Privileged Information Redacted
Pursuant to Section 388.112
of the Commission's Regulations**

Figure 5

Nova Sotia Average Carbonate Type Well

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of the Commission's Regulations

Offshore Nova Scotia Basin

Calculation of Average Well Economic Limit

(1620 Mcf/d)

Monthly Well Expenses							Amount
Monthly Operating Expense per Well							
CNSOPB reported SOEP operating costs			=	$64million for 19 wells			
			=	$64 million / 19		=	$ 215,000
Monthly Tolls per Well							
Maritimes Tolls at $1.5594 per Dth							
1.5594	x	1620 Mcf/d	x	30.4 days		=	$ 76,797
				Total Monthly Well Expenses			**$ 291,797**

Monthly Well Revenue								
Gas Revenue per Well								
Revenue @ EIA 10-year estimated gas price of $5.00 per Dth								
1620 Mcf/d	x	1060 Btu	x	30.4 days	x	$ 5.00	=	$ 261,014
Condensate Revenue per Well								
Revenue @ EIA 10-year estimated oil price of $32.00 per barrel								
Estimated average condensate yield of 19.12 barrels per MMcf								
1620 Mcf/d	x	30.4 days	x	0.01912 Bbl/Mcf	x	$ 32.00	=	$ 30,132
				Total Monthly Well Revenue				**$ 291,146**
				Balance				***$ (651)***

Offshore Nova Scotia Basin

Estimated Discovered Reserves (Bcf)

CNSOPB P50 Estimate vs. Rate-Time Based Recoverable Estimate

**Privileged Information Redacted
Pursuant to Section 388.112
of the Commission's Regulations**

Offshore Nova Scotia Basin

Estimated Discovered Reserves (Bcf)

CNSOPB P50 Estimate vs. SOEP Performance Adjusted Recoverable

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of the Commission's Regulations**

Offshore Nova Scotia Basin

Estimated Discovered Reserves (Bcf)

CNSOPB Discovered Fields [1]

Estimated Gas-in-Place

Field	CNSOPB P90 GIP (Bcf)	CNSOPB P50 GIP (Bcf)	CNSOPB P10 GIP (Bcf)
Venture	1781	2295	2957
Thebaud	746	1114	1661
Glenelg	514	659	845
S. Venture	454	628	868
Alma	545	626	720
Chebucto	491	588	703
N. Triumph	341	559	862
W. Sable	151	280	520
Citnalta	189	286	433
Arcadia	173	235	319
Onondaga	214	240	268
Primrose	208	257	319
Uniacke	148	196	259
Olympia	129	190	280
W. Venture N-91	127	159	199
Banquerreau	112	139	174
Intrepid	89	112	140
W. Venture C-62	58	72	95
W. Olympia	24	33	42
S. Sable	7	7	7
TOTAL	**6,501**	**8,675**	**11,671**

Estimated Recoverable Reserves

Field	CNSOPB P90 IRR (Bcf)	CNSOPB P50 IRR (Bcf)	CNSOPB P10 IRR (Bcf)
Venture	373	724	1329
Thebaud	257	428	676
Glenelg	227	408	694
S. Venture	273	407	576
Alma	246	382	562
Chebucto	171	363	690
N. Triumph	76	182	416
W. Sable	95	186	346
Citnalta	87	153	255
Arcadia	107	156	214
Onondaga	104	167	255
Primrose	74	127	207
Uniacke	65	124	224
Olympia	64	103	159
W. Venture N-91	56	90	139
Banquerreau	45	73	112
Intrepid	29	47	76
W. Venture C-62	12	21	34
W. Olympia	4	5	6
S. Sable	0	0	0
TOTAL	**2,360**	**4,147**	**6,971**
CNSOPB Recovery Factor	*50%*	*65%*	*80%*

(1) "Technical Summaries of Scotian Shelf - Significant and Commercial Discoveries" - Canada Nova Scotia Offshore Petroleum Board - November 2000

Offshore Nova Scotia Basin

Estimated Undiscovered Resources (Bcf)

P50 Case

**Privileged Information Redacted
Pursuant to Section 388.112
of the Commission's Regulations**

Exhibit No. __ (LWG-8)
Schedule No. 5
PUBLIC VERSION

Offshore Nova Scotia Basin

Estimated Reserves and Resources (Bcf)

P50 Case of Leon Giese

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Pursuant to Section 388.112
of the Commission's Regulations

PRESS CLIPPING
COUPURE DE PRESSE

The National Post (Metro) | 83607

Date 31.01.2004 Circ. 359,682 Page FP1 | 1 / 3

Natural gas reserves have been cut three times

Pengrowth threatened by Sable revision

BY CLAUDIA CATTANEO
Calgary Bureau Chief

CALGARY · Pengrowth Energy Trust could be hard hit by a downward reserve revision at the natural gas Sable Offshore Energy Project offshore Nova Scotia's coast, FirstEnergy Capital Corp. warned in a report to clients yesterday.

Analyst Patrick Bryden said the project is a significant property for the widely held trust, accounting for 16.1% of its reserve base as of year-end 2002.

If the trust cuts its reserve estimates for the project to match a revision made by Shell Canada Ltd. on Thursday, it would be "a dramatic revision," he said. "We view the trust as the entity that will be most adversely affected."

Shell Canada downsized reserves for its 31.3% stake in the project by 300 billion cubic feet, to 430 billion cubic feet. It was the third time in as many years it reduced the number. The new estimate is about a third of the original 1.1 trillion cubic feet Shell Canada had hoped to tap from Sable fields in the mid 1990s.

Pengrowth did not return phone calls. The trust is expected to update its reserve estimates in March, in conjunction with its year-end financial results.

Pengrowth purchased its 8.4% interest in the project from the Nova Scotia government in 2001, when the province sold its oil and gas Crown corporation, Nova Scotia Resources Ltd. The province had decided it was risky to continue exploring and developing projects in the offshore.

PRESS CLIPPING
COUPURE DE PRESSE
The National Post (Metro)
Date 31.01.2004
Circ. 359,682 Page FP1
83607
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The Calgary-based trust, one of Canada's largest, paid $265-million for the government's stake in Sable's gas production, and then another $122-million in two separate transactions for related facilities.

"All and all, it was a win-win," James Kinnear, chairman, president and CEO of Pengrowth, said at the time of the purchase. "It was a good deal for the government, because they got a fair price for it, and it's a good deal for us, because our numbers show it's accretive to our unitholders. It's gas in a tight market."

Since its entry in the project, Pengrowth has reduced reserve estimates twice.

"We anticipate that the issues at [the Sable Offshore Energy Project] will result in another difficult year for Pengrowth's reserves book when it reports year-end results in March," Mr. Bryden wrote in the report. "We also note that Pengrowth paid up through series of transactions, in conjunction with significant interim processing fees, to acquire and maintain its 8.4% working interest in the production and infrastructure of the project, which has now seen a material erosion in asset value."

Sable's other owners are ExxonMobil Corp., with a 51% interest, and its Canadian affiliate, Imperial Oil Ltd., with 9%.

Alan Jeffers, a spokesman for ExxonMobil Corp., said his company also recently reviewed Sable's reserves and Shell's estimate "is consistent with ours." However, he said ExxonMobil is not disclosing the magnitude of its reduction because it's not material to its overall reserve base.

"It's fair to assume that if Shell and Exxon are taking a more conservative view on reserves, it's hard to see that Pengrowth wouldn't," Mr. Bryden said.

While the reserve reduction won't affect 2004 production, Mr. Bryden said it could reduce project life from 20 years to 10 years.

Mr. Bryden rates the trust "underperform" and expects its units to return -13% in the next 12 months, including distributions and unit values.

The trust's units closed at $18.56 in Toronto yesterday, down $1.52.

Financial Post

ccattaneo@nationalpost.com

PUBLIC VERSION

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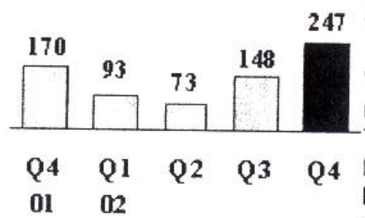
NEWS RELEASE · COMMUNIQUÉ

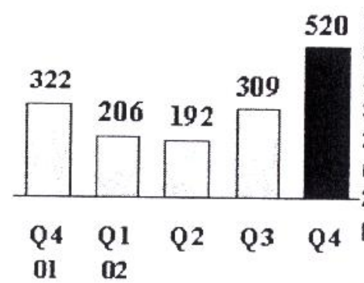
Shell Canada Announces Fourth-Quarter Earnings

Thursday January 30, 2003

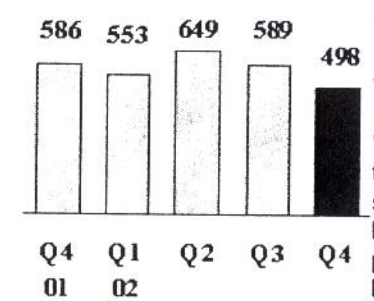
Earnings
($ millions)



Cash Flow
($ millions)



Capital Expenditures
($ millions)



Calgary, Alberta – Shell Canada Limited today announced 2002 fourth-quarter earnings of $247 million or $0.89 per Common Share compared with $170 million or $0.62 per share for the same period in 2001.

"We are pleased to report very strong results for the fourth quarter," said Tim Faithfull, President and Chief Executive Officer, Shell Canada Limited. "Good operational performance, following an extensive second-quarter maintenance schedule, allowed us to benefit from improved commodity prices and refining margins in the second half."

Full-year 2002 earnings of $561 million or $2.03 per Common Share compared with earnings of $1,010 million or $3.67 per share in 2001. Earnings for 2002 were reduced from record performance in 2001 as a result of lower commodity prices and refining margins.

Cash flow from operations for 2002 was $1,227 million compared with $1,495 million for 2001. Capital and exploration expenditures were $2,289 million, up from $2,027 million for 2001. Spending in 2002 included $1,646 million on the Athabasca Oil Sands Project compared with $1,494 million the previous year.

"We are now well into the start-up of the Athabasca Oil Sands Project," said Faithfull. "We are pleased to have achieved first bitumen production at the Muskeg River Mine before the end of 2002 and expect to produce synthetic crude oil from the upgrader before the end of the first quarter of 2003. Completing world-scale projects presents a range of challenges, especially when winter conditions become extreme. We are confident we can overcome them."

Investor Inquiries:	Media Inquiries:
Jim Fahner	Jan Rowley
Investor Relations	Public Affairs
(403) 691-2175	(403) 691-3899

SHELL CANADA LIMITED

SEGMENTED INFORMATION

Resources

Resources fourth-quarter earnings in 2002 were $152 million, up significantly from $79 million for the same period in 2001. Prices for natural gas and other commodities strengthened in the fourth quarter, exceeding 2001 levels. Natural gas and condensate volumes were lower than in the fourth quarter of 2001 due mainly to maintenance activities, temporary pipeline outages in Western Canada and field declines. Continued successful exploration and development investments have sustained full-year gas production close to 2001 levels. Peace River bitumen production increased with the completion of the drilling program, successfully achieving its 12,000 barrels per day objective. Operating expenses were higher compared with the fourth quarter of 2001, largely because of the elimination of Alberta government energy rebates that were in place in 2001. Full-year earnings for 2002 were $387 million compared with $600 million the previous year.

During the fourth quarter of 2002, Shell's share of natural gas production from Sable Offshore Energy Project (SOEP) averaged 153 million cubic feet per day. This was down from record levels seen in the fourth quarter of 2001, due mainly to maintenance work hampered by weather. SOEP full-year production for 2002 averaged 158 million cubic feet per day (Shell share), up slightly from 2001. Based on technical reviews completed at the end of 2002, Shell has revised its estimate of original sales gas reserves for the SOEP fields downward by approximately 90 billion cubic feet (bcf), to 700 bcf, and has reclassified approximately 200 bcf of sales gas reserves from the proven developed category to proven undeveloped. The reclassification was based on indications that more significant infill drilling and compression will be needed to maintain production and recover remaining reserves from the Tier I fields. These reserve changes will result in higher depreciation charges for Shell's share of SOEP, which are expected to increase Resources total depreciation expense for 2003 by approximately 20 per cent.

Shell continues to assess exploration and development opportunities in the shelf and deep water plays offshore Nova Scotia, and in the Mackenzie Delta. On the East Coast, development of Alma, the first of the planned SOEP Tier II fields, is underway and expected to be completed by the end of 2003. In the Mackenzie Delta, Shell is participating in an exploration well with Devon Energy Corporation and is a member of the Mackenzie Delta Producers Group currently working on regulatory applications to develop existing reserves in the area.

Oil Sands

PUBLIC VERSION

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Construction of the Athabasca Oil Sands Project (AOSP) is complete and the project commenced operations at the end of 2002. Oil Sands results for 2002 and the fourth quarter reflected a loss of $5 million due primarily to capital taxes on the assets.

The AOSP achieved a major milestone on December 29, 2002 with first bitumen production at the Muskeg River Mine, located north of Fort McMurray, Alberta. Initial bitumen recovery and quality was achieving design targets and meeting all required upgrading specifications. Deliveries of diluted bitumen into the Corridor Pipeline system commenced before year-end, enroute to the Scotford Upgrader, located near Fort Saskatchewan, Alberta. At the upgrader, the primary distillation units were successfully tested during the fourth quarter and commissioning and testing of the synthetic crude units was well underway at year-end. Shell Canada's share of capital expenditures for the full year 2002 was $1,646 million, including $186 million for Scotford refinery modifications. Currently, total project costs are not expected to be materially different from previously reported estimates.

On January 6, 2003, a hydrocarbon leak at the Muskeg River Mine caused a fire which was quickly extinguished. Damage was mainly limited to electrical cables in the solvent recovery area of the froth treatment plant. It has been determined that the hydrocarbon leak, which resulted in the fire, was caused by failure of a piping connection. At present, we estimate repair costs to be in the order of $75 million ($45 million Shell share), although much will depend on weather conditions. The company expects to draw on extensive project insurance coverage to recover repair costs.

The primary focus during the first quarter of 2003 will be on completing repairs to the froth treatment plant at the mine and commissioning and testing the synthetic crude units at the upgrader. Start-up of the synthetic crude units is a complex process, initially using light oil, gradually introducing heavier product, and ultimately running bitumen supplied by the mine. First production of synthetic crude oil from the Scotford Upgrader is expected before the end of the first quarter and production volatility can be expected during initial operations.

Both the mine and upgrader were turned over to operations by year-end and all start-up and operating costs are being expensed in 2003. The project will be in start-up mode in the first quarter of 2003 and total expenses are expected to exceed production revenues during this period. The project is targeted to ramp up to the designed bitumen production rate of 155,000 barrels per day in the third quarter of 2003.

Oil Products

Oil Products earnings in the fourth quarter were $108 million, up from $85 million for the same period in the previous year. Higher refining margins were the main reason for this improvement. Marketing margins were weak during 2002 and compressed further in the fourth quarter, as commercial and retail prices did not fully reflect the higher cost of light oil products. Restructured technology funding arrangements with the Royal Dutch/Shell Group added approximately $17 million to earnings in the fourth quarter. Fourth-quarter operating expenses increased over the same period of 2001 mainly due to higher planned refinery shutdown and marketing expenses. Full-year 2002 earnings were $198 million compared with record earnings of $401 million in 2001.

The gasoline desulphurization projects at the Sarnia and Montreal refineries successfully started up in the fourth quarter ahead of schedule and on budget. This will allow all three of the company's refineries to produce gasoline with an average sulphur content of 30 parts per million, well ahead of the January 1, 2005 legislated deadline.

Corporate

Corporate expenses in 2002 were $19 million compared with earnings of $9 million in 2001. Higher net financing costs were not fully offset by interest income received for prior-period income tax settlements. In financing its capital spending program, the Company issued $745 million of medium-term notes in 2002 and increased outstanding commercial paper by $459 million. Sales of accounts receivable under the Company's accounts receivable securitization program increased by $170 million during the year, bringing the program total to $520 million since it was first established in 2000.

Reductions in equity market valuations over the last two years have eroded Shell Canada's pension surplus. While it is anticipated that a contribution will be required in 2003, it is not expected to be significant. To reflect the expected market performance of plan assets, the long-term rate of return was reduced on January 1, 2003 to 7.5 per cent from 8.0 per cent adopted in 2001. The overall change in pension expense in 2003 is expected to reduce earnings by $25 million compared to 2002.

This information includes "forward looking statements" based upon current expectations, estimates and projections of future production, project start-up and future capital spending that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Corporation. These risks and uncertainties include, but are not limited to, changes in: market conditions, law or government policy, operating conditions and costs, project schedules, operating performance, demand for oil, gas and related products, price and exchange rate fluctuations, commercial negotiations or other technical and economic factors.

View the complete quarterly results. (PDF: 47 KB)

Adobe Acrobat Reader required.

Comments or questions about Shell Canada or Shell Canada's Web site?
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PRESS CLIPPING | The Chronicle-Herald | 83607

COUPURE DE PRESSE | Date 30.01.2004 | Circ. 88,859 Page C1 | 1 / 3

Shell cuts Sable gas estimates

Energy giant trims reserves figure by 40 per cent to 430b cubic feet

By Judy Myrden
Business Reporter

For the third straight year, Shell Canada Ltd. has slashed estimates of its share of natural gas reserves at the Sable offshore project.

"It's clearly a disappointment," Jan Rowley, a Shell Canada spokeswoman, said Thursday.

Shell — which holds a 31.3 per cent share of the project — slashed estimates by 40 per cent, from 730 billion cubic feet to 430 billion cubic feet.

Originally, Shell estimated its share to be 1.1 trillion cubic feet of the 3.6-trillion cubic-feet estimate for the entire project.

That assessment is contained in the company's fourth-quarter results released Thursday.

Ms. Rowley said it's "too early to tell" if the reduction in gas reserves will shorten the projected 25-year life of the project.

Shell indicated Sable owners are talking with EnCana Corp. of Calgary about incorporating its nearby Deep Panuke field into their project to extend the life of Nova Scotia's first gas development. Development of Deep Panuke was put on hold last year.

Nova Scotia Energy Minister Cecil Clarke called Shell's adjustment of reserve estimates a "disappointment," not only for the operators but also for provincial coffers.

Based on Shell's downgrade, the province has reduced its estimates of how much money it will collect in royalties over the life of the project, which started shipping gas in late 1999.

The province is now forecasting total royalties from the project at between $600 million and $1.1 billion, down from estimates of $1.2 billion to $2.3 billion, Mr. Clarke said.

"It certainly is a reality check and indicates the risks involved with the industry," he said.

But Mr. Clarke called it a "rallying call" for industry to start drilling more wells off Nova Scotia.

The lead partner in the project, ExxonMobil, agrees with Shell's numbers.

Alan Jeffers, ExxonMobil's spokesman, confirmed its partners downgrade of reserves.

"This is in line with our view," Mr. Jeffers said at ExxonMobil's Halifax office.

Shell also released "disappointing" results from another well, Glenelg, part of the second phase of the Sable project.

The Sable partners had hoped Glenelg would come on stream between 2004 and 2007.

A technical review of a development well drilled at Glenelg last year indicates it is not economical as a stand-alone project, states Shell.

Mr. Jeffers said the partners are still trying to make Glenelg economical.

Last year, natural gas production at the Sable project declined, but startup of the Alma field late in the year offset that decline, with the new volumes adding about 25 million cubic feet of gas per day, Shell says.

• See South Venture/ C5

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South Venture development proceeding

• continued from / C1

During the fourth quarter of 2003, Shell Canada's share of natural gas production from the Sable project averaged 133 million cubic feet of gas per day, compared with 153 million cubic feet of gas per day in the same period in 2002.

Ms. Rowley said Shell and the other Sable partners are taking steps to improve gas production by proceeding with the development of the South Venture field, part of the second phase and expected to start production later this year, and adding field compression in 2006.

"The big plan always was Phase 2 was needed to maintain production. There hasn't been an acceleration," Ms. Rowley said.

Average daily production at Sable in 2003 was about 430 million cubic feet of gas.

The Sable partners are ExxonMobil, Shell Canada, Imperial Oil, and Mosbacher Operating and Pengrowth Trust.

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COUPURE DE PRESSE Date 02.03.2004 Circ. 88,859 Page F1 1 / 2

Shell confirms problems with exploratory well

By **JUDY MYRDEN**
Business Reporter

CALGARY — Problems at a deepwater exploratory well being drilled near Sable Island are causing a delay in completing the well and millions of dollars in cost overruns, a partner in the project confirmed here Monday.

"There have been some issues associated with it, and the cost will be higher than we originally anticipated," Dave Collyer, **Shell Canada's** vice-president of frontiers, confirmed Monday at an energy conference.

"I expect we've got another month or so to go before we get to total depth, but that will depend on how the drilling goes. ... It is longer than originally planned and it's because of the challenges we've run into in the drilling operations."

Shell is a partner, along with **EnCana Corp.** of Calgary, and Norwegian rig owners **Ocean Rig**, in the Weymouth well, located about 250 kilometres southeast of Halifax. Drilling began in November and was expected to be completed by mid-March.

Drilling in the deeper waters off Nova Scotia can cost on average $500,000 per day for the lease of the rig and other associated costs, with the total cost between $75 and $100 million per well, Mr. Collyer told delegates at the conference on North America natural gas markets.

The industry veteran would not comment on the specific problems at the Weymouth well, except that during his speech he outlined the challenges facing producers in the North Atlantic's deep water.

"All of these wells — it's just not Weymouth — they're all difficult drilling conditions. These are deep wells, high pressure, high temperature in a basin that really isn't proven out yet," said Mr. Collyer, who works from Shell's Calgary headquarters.

The world's largest and most modern oil rig, the Eirik Raude, owned by Ocean Rig of Stavangar, Norway, is drilling the Weymouth well. The well depth has not increased in the past few weeks, according to the Canada-Nova Scotia Offshore Petroleum Board's website.

■ See Difficulties / F2

Difficulties of offshore drilling not unknown to Shell

Continued from F1

The targeted drilling depth for the Weymouth well is 6,627 metres, but for the past two weeks, work has stalled at 5,451 metres.

Shell Canada knows the high cost of searching for oil and gas in the harsh environment of the North Atlantic.

Two years ago, it abandoned its exploratory well Onondaga, just southwest of Sable Island, because there was not enough gas. It is believed to be the most expensive well drilled in Canada, with the final tab coming in at $90 million — $30 million over budget.

Mr. Collyer gave a cautionary speech about exploring for energy off Nova Scotia at the conference, sponsored by the Canadian Energy Research Institute of Calgary.

Last month, Shell sent warning signals about how much gas is in the Sable fields. It cut estimates of reserves from three trillion cubic feet to 1.35 trillion after new analysis of production data from the province's only gas producing project.

One partner in the project, **Pengrowth Energy Trust** of Calgary, stated that Sable could run out of gas by 2010, 10 years earlier than first thought.

Mr. Collyer predicts production from Sable, which started in late 1999, to remain stable at about 450 million cubic feet of gas per day until 2010, but after that, the future becomes uncertain.

"It will depend on exploration results," Mr. Collyer told reporters after his speech.

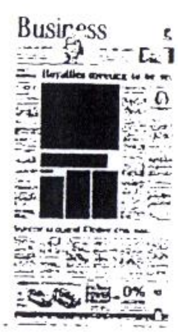
Currently, two wells are being drilled off Nova Scotia, the Weymouth well and a shallow water well that was recently completed and is now being tested by **Canadian Superior Energy**. Results are promising results, the company said.

Otherwise, activity offshore this year is scarce, with only one new well being drilled this spring in deep water by **Marathon Oil** of Houston, near a gas discovery made by the company.

"I think industry generally is still optimistic about the longer-term potential (of Nova Scotia). But I think you also have to be realistic about the near-term outlook, the level of activity that we're seeing and the results."

The conference continues today.

(jmyrden@herald.ca)



PUBLIC VERSION

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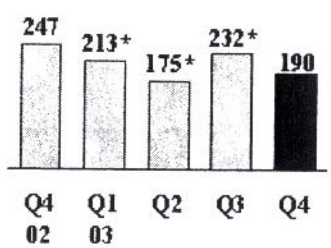
NEWS RELEASE · COMMUNIQUÉ

Shell Canada Announces Year-End Results

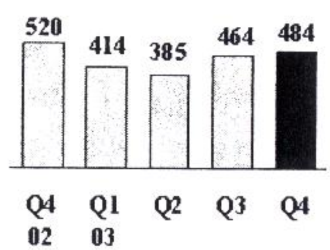
Thursday, January 29, 2004

Earnings
($ millions)

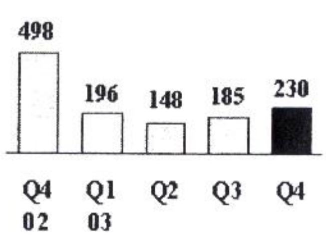


*Restated

Cash Flow
($ millions)



Capital Expenditures
($ millions)



Calgary, Alberta – Shell Canada Limited announces full-year 2003 earnings of $810 million or $2.95 per Common Share, up about 45 per cent from $561 million or $2.03 per share in 2002.

Fourth-quarter earnings of $190 million or $0.69 per Common Share compared with $247 million or $0.89 per share for the fourth quarter of 2002.

Cash flow from operations for 2003 was $1.7 billion compared with $1.2 billion in 2002. Capital and exploration expenditures totalled $759 million, down from $2,289 million for 2002, which included $1,646 million for the Athabasca Oil Sands Project.

"Strong commodity prices, record earnings in our conventional upstream business and the start-up of the Athabasca Oil Sands Project contributed to record cash flow from operations in 2003," said Linda Cook, President and Chief Executive Officer, Shell Canada Limited. "Additionally, Oil Products reported their second best earnings in the Company's history. These strong results enabled Shell to pay down a significant amount of debt and increase dividends to shareholders. Progress in ramping up the Athabasca Oil Sands Project has been encouraging, with production averaging about 130,000 barrels of bitumen per day in the fourth quarter, up 12 per cent from the previous quarter."

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SHELL CANADA LIMITED

SEGMENTED INFORMATION

Resources

Resources achieved record earnings of $618 million in 2003, up 60 per cent from $387 million in 2002, primarily due to stronger commodity prices. In the fourth quarter of 2003, earnings were $88 million compared with $152 million in the same period last year. Fourth-quarter earnings decreased from the same period last year due to the write-off of Glenelg (a Sable Offshore Energy Project well), higher Western Canada dry hole expenses, increased operating expenses and higher Sable Offshore Energy Project (SOEP) depreciation charges. Sales volumes were lower than in the corresponding quarter of 2002 primarily due to field decline in Western Canada and SOEP.

Natural gas production from SOEP in 2003 reflected issues with well performance and natural decline in the Tier 1 fields (Venture, Thebaud and North Triumph). Several well workovers earlier in 2003 and the start-up of the Tier 2 Alma field late in the year partially offset production decline. The new volumes from Alma added approximately 25 million cubic feet per day (Shell share) to overall SOEP production in December.

Based on new data (drilling results, seismic and production performance) and ongoing technical reviews, Shell has revised its estimate of original sales gas reserves (ultimate recovery) for the SOEP fields (see Reserves section). Shell and SOEP owners are taking steps to sustain future production performance and infrastructure utilization. These include proceeding with the development of the South Venture field (scheduled to start production late 2004) and field compression (scheduled to start up in 2006). The potential for tying additional discovered gas volumes from the Sable Basin into SOEP is under review. At the same time, the SOEP owners are evaluating potential development synergies between SOEP and the Deep Panuke field. Shell is also participating in the Weymouth deepwater well offshore Nova Scotia, which is currently drilling.

In the Mackenzie Delta, Shell is working to progress development of the Mackenzie Gas Pipeline and Shell's wholly owned Niglintgak field. In 2003, the project made significant progress toward regulatory filings planned for 2004.

Oil Sands

Oil Sands results in 2003 reflected a loss of $142 million. The Athabasca Oil Sands Project became fully operational in June and generated its first profit in the third quarter. Production ramp-up continued in the fourth quarter and Oil Sands generated earnings of $19 million. Production volumes increased, averaging 84 per cent of design rate, but high costs and low price realizations relative to Edmonton light crude oil (Edmonton PAR) affected earnings during this transitional period.

Fourth-quarter production averaged approximately 130,000 barrels per day (78,000 Shell share) of bitumen, up 12 per cent from approximately 115,000 barrels per day (70,000 Shell share) in the third quarter. The project continued to meet technical expectations, producing at or above the design rate of 155,000 barrels per day on an increasingly regular basis. The focus remains on continuous improvement -- safely and steadily increasing production while consistently meeting the needs of customers.

The Company expects the level of non-recurring expenses, which contributed to high costs in the fourth quarter, to fall as bitumen production increases towards and stabilizes at the design rate. Shell's long-term goal is to be the lowest cost producer of synthetic crude oil as measured by unit cash operating costs (Note 1). The long-term target range for unit cash operating cost is $10-12 per barrel, based on natural gas prices at $4.00 per thousand cubic feet in Alberta. At natural gas price levels experienced in 2003, this target range would equate to $12-14 per barrel. Continued ramp-up effects on costs and volumes will likely result in unit cash costs above this target range in 2004, the first full year of operations.

The long-term target for upgraded bitumen price differentials is to average about $2.00 per barrel below Edmonton PAR (based on West Texas Intermediate crude oil prices in the $18 per barrel range). In 2003, the average synthetic crude price was at a wide discount to Edmonton PAR. This was mainly due to wide heavy oil price differentials and higher ratios of heavy synthetic product in the overall sales mix during start-up. Price realizations relative to Edmonton PAR are expected to improve as operations stabilize, products become more established in the marketplace and various upgrader optimization initiatives are undertaken. Differentials in 2004 should improve versus 2003 but are expected to be considerably wider than the long-term target.

The Company continues to seek recovery of costs resulting from the January 2003 fire and related freezing damage. About two-thirds of the costs incurred have now been recovered from insurers and further claims are pending. Shell continues to pursue claims for lost profits resulting from production delays caused by the fire.

Oil Sands expects a regulatory decision for the Jackpine Mine in the first quarter of 2004. This project includes a mining and extraction facility on the eastern portion of Lease 13 to produce approximately 200,000 barrels per day of bitumen. Timing of the development will depend on the outcome of the regulatory process, market conditions, project costs and sustainable development considerations.

Reserves

Overall, revisions, extensions and additions to Shell Canada's proved reserves in 2003 were positive. Upward revisions for Oil Sands and Foothills business units were partially offset by a downward revision at the Sable Offshore Energy Project.

Revisions to proved reserves include Oil Sands additions of 68 million barrels of oil equivalent (BOE) and improved recovery and extensions in the Foothills of 17 million BOE, which were partly offset by a downward revision of 63 million BOE for the SOEP fields. After 2003 production of 70 million BOE, total year-end proved reserves reflected a net decrease of 51 million BOE.

The Oil Sands reserves additions include 68 million BOE proved plus 50 million BOE probable reserves. Shell added these volumes on the basis of core hole drilling completed in 2003 within the approved development area for the Muskeg River Mine.

The revision at SOEP is based on the interpretation of new data, and technical and management reviews completed in December 2003, resulting in reserve reductions in the Alma, South Venture and Tier 1 fields. In addition, a technical review of the Glenelg Tier 2 development, incorporating disappointing results from a 2003 development well, concluded that a stand-alone development of the field is not economically viable at this time. Shell's share of original sales gas reserves (ultimate recovery) for SOEP has therefore been revised downward by a further 300 billion cubic feet, to approximately 430 billion cubic feet. These reserve changes will contribute to higher depreciation charges for Shell's share of SOEP, which will increase Resources total depreciation expense for 2004 and reduce earnings by approximately $30 million after tax.

Oil Products

In 2003, Oil Products delivered its second highest earnings of $345 million, up by 74 per cent versus 2002, mainly due to stronger refinery performance. Refinery margins weakened in the fourth quarter of 2003 and earnings were $72 million, down from $108 million for the same period in the previous year.

Work has commenced on distillate hydrotreater projects, estimated to cost approximately $400 million, at the Montreal East and Scotford refineries. These projects, along with the recent agreement with Suncor related to the Sarnia Refinery, will enable Shell to meet the ultra-low sulphur requirements for diesel, which come into effect in 2006.

In the second quarter of 2004, there will be a major maintenance shutdown at the Montreal East Refinery. Sarnia and Scotford refineries will also undertake minor maintenance shutdowns during the first half of the year.

Corporate

In the fourth quarter, the Company initiated the expensing of stock options, beginning with options granted during 2003. The total 2003 expense was $12 million (allocated across the business units). The fourth-quarter expense was $3 million and prior quarters' earnings have been restated to include an additional expense of $3 million per quarter.

To reflect the expected market performance of its pension plan assets, Shell reduced the long-term rate of return on January 1, 2004, to 7.25 per cent from the 7.5 per cent adopted in January 2003. The Company expects the overall change in pension expense in 2004 to reduce earnings by about $20 million compared with 2003. Related expenses will be allocated to each of the business units.

Corporate reported negative earnings of $11 million for 2003 compared with negative earnings of $19 million in 2002. In the fourth quarter, earnings were $11 million compared with negative earnings of $8 million during the same period of last year due to positive income tax settlements.

Cash Flow and Financing

Strong commodity prices continued in the fourth quarter, yielding cash flow from operations of $484 million. Working capital reductions in the quarter provided an additional $363 million. This included an additional $106 million of accounts receivable sales under Shell's accounts receivable securitization program. Lower oil product inventories also contributed to the reduction in working capital. After cash invested, dividends and purchase costs related to Shell's normal course issuer bid, net cash available of $519 million was used to pay down outstanding debt. Shell reduced commercial paper outstanding by $325 million to $149 million under its $1.5 billion commercial paper program. A $184 million capital lease obligation relating to the AOSP was retired and $13 million of medium term notes were repaid.

During 2003, Shell reduced total balance sheet debt by $711 million to $885 million. Securitized receivables were increased by $61 million to $581 million.

Note

1. Unit cash operating cost is a key internal and external measure used to evaluate the performance of the Oil Sands segment of the Company. Unit cash operating costs for Oil Sands are defined as: "Operating, selling and general expenses" plus "Costs of goods sold" less purchases of third party blend stocks, divided by "Synthetic crude sales excluding blend stocks." Shell has not disclosed actual unit cash operating costs in 2003, as this was not considered meaningful information during the start-up period. The Company plans to begin disclosing unit cash operating costs in 2004. Unit cash operating cost does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles and therefore may not be comparable with the calculation of similar measures for other companies.

This document includes "forward looking statements" based upon current expectations, estimates and projections of future production, project start-up and future capital spending that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Corporation. These risks and uncertainties include, but are not limited to, changes in: market conditions, law or government policy, operating conditions and costs, project schedules, operating performance, demand for oil, gas and related products, price and exchange rate fluctuations, commercial negotiations or other technical and economic factors.

View the complete quarterly results. (PDF: 385 KB)

Adobe Acrobat Reader required.

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Please contact us at: questions@shell.com

PENGROWTH

NEWS RELEASE

Attention: Financial Editors **Stock Symbol: PGF.UN, TSX; PGH, NYSE**

PENGROWTH ENERGY TRUST ANNOUNCES PRELIMINARY 2003 YEAR END RESERVES RECONCILIATION

(**Calgary**, February 2, 2004) /CNW/ - Pengrowth Energy Trust ("Pengrowth") announced today that its independent reserves appraiser Gilbert Laustsen Jung Associates Ltd. ("GLJ") has provided preliminary year end estimates of company reserves effective December 31, 2003. GLJ's estimates of reserves attributed to Pengrowth's 8.4% working interest in the Sable Offshore Energy Project ("SOEP") are consistent with the reduction to SOEP reserves announced by Shell Canada Resources Limited on January 29, 2004. On a net basis GLJ estimates a 50 Bcf reduction to proved sales gas reserves determined at project startup from 176 Bcf to approximately 126 Bcf. Downward revisions to SOEP reserves were considered by Pengrowth in the acquisition of SOEP facilities interests in 2003 and were referenced in Pengrowth's press release dated October 31, 2003. The adjustments are primarily due to the removal of the Glenelg field from current development plans, the exclusion of an undrilled fault block at North Triumph and poorer than anticipated performance for the Venture field.

Pengrowth's budgeted outlook for distributions in 2004 is unchanged as a result of the SOEP reserve revision. Production declines will be offset by the anticipated startup of the South Venture field in late 2004 and the introduction of compression in 2006. The 2003 acquisition of SOEP facilities interests by Pengrowth reduces operating costs by approximately Cdn $28 to $30 million annually and GLJ projects pre capex cash flow from Pengrowth's SOEP interest at Cdn $83 million for 2004 using the GLJ January 1, 2004 base case price forecast and the proved plus probable reserves case.

Preliminary revisions to proved reserves for Pengrowth's overall oil and gas property portfolio are 17.1 mmboes or approximately 9.3% of Pengrowth's proved reserves. SOEP now represents approximately 10% of Pengrowth's total proved reserves. Although not directly comparable due to a change in reserve definitions under new National Instrument 51-101 the proved plus probable reserves are similar to Pengrowth's previously reported "Established Reserves". There has been a reduction of 15.3 mmboes or 7.1% to the established reserves reported by GLJ for December 31, 2002, substantially all of which can be attributed to reductions in reserves for Pengrowth's SOEP interest.

The following preliminary GLJ reserves reconciliation is presented for year end December 31, 2003:

000's of BOE's	Proved Producing	Proved	***"Established"****
December 31, 2002	130,868	181,381	***214,814***
Exploration and Development	4,190	2,720	***2,710***
Revisions	1,090	(17,110)	***(15,267)***
Acquisitions	240	490	***620***
Dispositions	(410)	(420)	***(510)***
Production	(17,897)	(17,897)	***(17,897)***
December 31, 2003	118,081	149,164	***184,470***
Reserve Life Index (years)	7.2	8.9	***10.6***

*Established formerly defined as proved plus 50% of probable. The closing balance is proved plus probable reserves in accordance with NI 51-101.

Pengrowth's comprehensive 2003 year end financial results will be released on or about March 1, 2004.

PENGROWTH CORPORATION
James S. Kinnear, President

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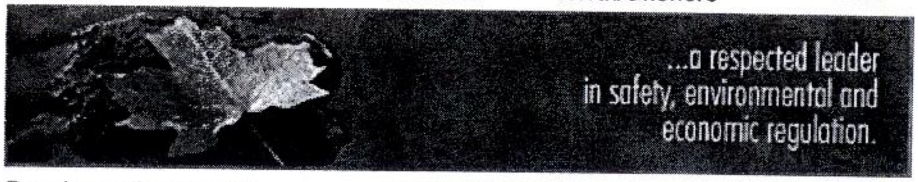
National Energy Board | Office national de l'énergie

Canada



National Energy Board | Office national de l'énergie

NewsRelease

444 Seventh Avenue SW, Calgary, Alberta T2P 0X8

04/07
For immediate release
15 April 2004

National Energy Board releases updated status report on Canada's natural gas resources

CALGARY - The National Energy Board has released a report on the current status of its estimates of ultimate potential for conventional natural gas in Canada. Canada has 14 214 billion cubic metres (501 trillion cubic feet) of gas, of which 8 148 billion cubic metres (286 trillion cubic feet) is still undiscovered. One third of the undiscovered resources will be found in the Western Canada Sedimentary Basin.

The report provides a new estimate for the Alberta portion of the Western Canada Sedimentary Basin of 5 855 billion cubic metres (207 trillion cubic feet) of marketable gas. This estimate is marginally larger than the latest estimate from the Alberta Energy and Utilities Board (EUB) in 1992 of 5 600 billion cubic metres (200 trillion cubic feet). It is also larger than the latest estimate from the Canadian Gas Potential Committee in 2001 of 5 600 billion cubic metres (203 trillion cubic feet).

The NEB concludes that the 80 thousand wells drilled in Alberta from 1990 to 2000 proved up a large part of the previously undiscovered resources, but did not add significantly to the expectations of the province's ultimate potential or total gas resources.

The NEB report also concluded that a larger portion of the undiscovered volumes of natural gas will be found in the shallower horizons than previously estimated. As a result, there will continue to be a need for the very high drilling levels experienced over the past few years in order to maintain current production levels as these horizons contain small pools which are subject to high rates of production decline.

The report also identifies the need for a new assessment of northeastern British Columbia as there have been large, new discoveries made and activity levels there have increased over the past few years. Further, the shallow water portion of the Scotian Shelf, offshore Nova Scotia, needs a new assessment due to the recent production declines from the Sable Island Fields and due to the disappointing results from exploration efforts

PUBLIC VERSION

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over the past few years.

The National Energy Board is an independent federal agency which regulates several aspects of Canada's energy industry. Its purpose is to promote public safety, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. As part of its mandate, the NEB monitors the supply of all energy commodities in Canada and publishes reports on energy, called Energy Market Assessments, of which this is one.

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For a copy of *Canada's Natural Gas Resources: A Status Report* contact:

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444 Seventh Avenue SW
Calgary, Alberta
T2P 0X8
Telephone: (403) 299-3562
Telecopier: (403) 292-5576

Exhibit No. __ (LWG-10)
PUBLIC VERSION

Offshore Novia Scotia Basin

Projected Production Profile - Leon Giese P50 Case

**Privileged Information Redacted
Pursuant to Section 388.112
of the Commission's Regulations**

Offshore Nova Scotia Basin

Calculation of Field Reserve Economic Limit

(75 Bcf)

Year	Condensate (Bbl)	Gas (Mcf)	Total Sales	Total Expenses	Net Cash Flow (CF)
1	0	0	$0	$139,200,000	-$139,200,000
2	315,673	16,510,074	$97,604,918	$28,325,810	$69,279,108
3	291,144	15,227,193	$90,020,731	$26,325,285	$63,695,446
4	223,304	11,679,054	$69,044,699	$20,792,317	$48,252,382
5	165,679	8,665,217	$51,227,378	$16,092,540	$35,134,838
6	122,925	6,429,116	$38,007,904	$12,605,563	$25,402,341
7	91,203	4,770,051	$28,199,779	$10,018,418	$18,181,361
8	67,668	3,539,116	$20,922,689	$8,098,898	$12,823,791
9	50,206	2,625,830	$15,523,487	$6,674,719	$8,848,768
10	37,250	1,948,222	$11,517,576	$5,618,057	$5,899,519
11	27,637	1,445,474	$8,545,409	$4,834,072	$3,711,337
12	20,505	1,072,462	$6,340,225	$4,252,398	$2,087,827
13	15,214	795,708	$4,704,099	$3,820,827	$883,272
14					
Month 1	1,075	56,203	$332,262	$302,643	$29,619
Month 2	1,048	54,822	$324,099	$300,489	$23,610
Month 3	1,022	53,475	$316,137	$298,389	$17,748
Month 4	997	52,162	$308,371	$296,341	$12,030
Month 5	973	50,880	$300,795	$294,342	$6,453
*** Month 6**	**949**	**49,630**	**$293,406**	**$292,393**	**$1,013**
Month 7	926	48,411	$286,196	$290,492	-$4,295

* Reserves depleted in 13.5 years.

Rate of Return Equation: $\mathrm{NPV} = 0 = \sum_{t=0}^{T} \frac{\mathrm{CF}_t}{(1+\mathrm{IRR})^t} = \mathrm{CF}_0 + \frac{\mathrm{CF}_1}{(1+\mathrm{IRR})^1} + \frac{\mathrm{CF}_2}{(1+\mathrm{IRR})^2} + \ldots + \frac{\mathrm{CF}_T}{(1+\mathrm{IRR})^T}$

IRR (Internal Rate of Return) = 24.40% (Based on monthly time steps)

Expense Assumptions

Development Expenses

$60,000,000	Platform
$46,000,000	Well Cost
$33,200,000	Pipeline Cost (20 mi)
$139,200,000	

Monthly Operating Expense

$215,000 / month

Transportation Tolls

$1.5594 per Dth

Revenue Assumptions

Estimated Gas Price

$5.00 / Dth

Estimated Condensate Price

$32.00 / barrel

Estimated Average Condensate Yield

19.12 barrel / MMcf

BTU Content

1060

Exhibit No. ___ (LWG-12)

PUBLIC VERSION

Canada - Canadian Press

Deep water canyon off N.S. known as the Gully designated protected area

ONLINE

Fri May 14, 2:22 PM ET

KEITH BONNELL

HALIFAX (CP) - A deep underwater canyon off the coast of Nova Scotia that's teeming with sea-life and rich in rare coral has been deemed a protected area by the federal government.

Federal Fisheries Minister Geoff Regan announced Friday that a canyon near Sable Island, known as the Gully, has been declared a marine protected area under the Oceans Act. "We are protecting a very important area that is home to a great diversity of life," Regan said at a news conference.

The designation is meant to guard the Gully against pollution, fishing and oil and gas exploration that could hurt the animals and plant life that thrive in its depths.

Located on the edge of the Scotian Shelf, the Gully is the largest marine canyon in the western North Atlantic.

It is a habitat for sea birds, fish, dolphins, sperm whales and the endangered northern bottlenose whale. It's also home to 21 identified species of rare deep-sea corals.

"It is a very important eco-system," said Regan. "It's vital that we protect it."

The Gully is about 80-kilometres-long and 50-kilometres-wide. It reaches down more than 2,500 metres at its mouth.

The news was welcomed by environmentalists, who have fought for almost a decade to see it protected.

"I think it was a good day. It's a beautiful area, a unique area," said Mark Butler of the Ecology Action Centre, an East Coast environmental advocacy group.

The Gully is the second of what federal officials hope will, over the next decade, become a system of 11 marine protected areas on both Canadian coasts and in the Arctic.

The first was the Endeavour Hydrothermal Vents off the Pacific coast, announced last year.

Despite taking strong steps to protect the Gully, the fisheries minister left the door open to possible oil exploration in the outer areas of the canyon.

Oil rigs and fishing boats are expected to be prohibited in the core but may be allowed to operate along the canyon's sandy, shallow banks.

Regan said all projects would be evaluated and assessed for any potential harm they could cause.

Jim Dickey, CEO of the Canada Nova Scotia Offshore Petroleum Board, said his organization has not authorized any exploration in the Gully for the several years, in anticipation of the new, protected designation.

The Primrose field is the only petroleum licence in the Gully and was classified by the board as a significant discovery in 1985.

It is licensed to Shell, but the rights to the site, estimated at a value of $35 million, have not been exercised.

"It's going to depend on the individual application and any effects they're going to have on the Gully," said Dickey.

"It's not closed entirely."

The boundary lines will also allow some fishing for swordfish, halibut and shark in the canyon's head and sides and near the banks.

Troy Atkinson, head of the Nova Scotia Swordfishermen's Association, expressed disappointment with the final boundaries.

He said his group only found out in the late stages of the process that the whole of the canyon's core would be off limits.

"They've given us something on paper, but it's not likely something we'll be able to use."

He said while fishermen will still be able to catch their quotas, costs for six vessels that have traditionally fished the area will increase as they are forced to look elsewhere.

Exhibit No. __ (LWG-13)
PUBLIC VERSION

Nova Sotia Average Sandstone Type Well

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Shell cuts Sable reserves estimate

LOWERED BY 60%

Revision called 'black mark' for East Coast project

BY CLAUDIA CATTANEO
Calgary Bureau Chief

CALGARY · **Shell Canada Ltd.** cut for the third time yesterday its reserve estimate for the Sable Offshore Energy Project, marking another defeat for the East Coast.

The Calgary-based company said it downsized its estimated gas reserves for its 31.3% share of the project by 60%, or by another 300 billion cubic feet, to approximately 430 billion cubic feet. At today's gas prices, 300 billion cubic feet of natural gas is worth US$1.8-billion.

Shell Canada's new estimate is about a third of the 1.1 trillion cubic feet it had hoped to tap from the discovery in the mid-1990s — or 2.3 trillion cubic feet for the entire project.

Tom Ebbern, research director at Tristone Capital Inc., said Shell's revision was unexpected and its size "pretty shocking."

He said it suggests original numbers were "overly optimistic" and that production from the $2-billion facility, linked to a $1-billion pipeline, will go into decline next year and outlive its reserves. Sable produces 475 million cubic feet to 500 million cubic feet a day.

"Without additional fields being discovered in the East Coast, this is yet another black mark against the Scotian Shelf," Mr. Ebbern said.

Sable's other owners, **ExxonMobil Corp.**, with a 51% interest, and its Canadian affiliate, **Imperial Oil Ltd.**, with 9%, also reduced their Sable estimates after undertaking their own evaluations. **Pengrowth Corp.**, an oil and gas trust, holds another 8.4%.

The reserve revision at Sable — the only producing energy project offshore Nova Scotia — comes after a long list of expensive exploration failures that have dampened industry enthusiasm for the region, which had been expected to become a major source of energy for Eastern Canada and the Eastern United States. The future of its only other major gas discovery — **EnCana Corp.**'s Deep Panuke — remains unclear.

"It's a disappointment, but it is a fact of life in a new basin where the production history is still being written," said Jan Rowley, a spokeswoman for Shell Canada. "Obviously, we are going to continue to work with partners and on our own to continue to explore the shallow and the deep water, because we still think it has potential."

See SHELL on Page FP4


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Reserve revisions not tied to cuts at parent company

SHELL

Continued from Page FP1

The Sable downgrade comes on the heels of controversial reserve changes at Shell Canada's parent, Royal Dutch/Shell Group, on Jan. 9 that moved 3.9 billion barrels of oil and gas finds booked as proven between 1996 and 2001 into categories with less certainty of commercial exploitation. The change hammered the firm's stock price, shook confidence in its management and prompted a class-action lawsuit in the United States that claims Shell "deliberately violated accounting rules and guidelines" by overstating its proven reserves.

Ms. Rowley said the Sable reserve revisions are not connected to those of its parent. She said the downgrade was made after obtaining well performance data and because of disappointing drill results.

The company said the write off of its Glenelg unsuccessful well, which had been expected to be linked to the Sable project and help offset declines from wells already in production, contributed to a decline in fourth quarter earnings to $190-million, or 69¢ a share, down from $247-million (89¢) in the same period of 2002.

Ms. Rowley said Sable's owners are in discussions with EnCana, which is interested in using the Sable facilities to reduce the cost of developing Deep Panuke.

Indeed, Mr. Ebbern said the reserve cut may be good news for EnCana, which may be able to work out a deal to use the facilities sooner than had been expected.

Shell Canada said its overall reserves increased because of additions from its Athabasca Oil Sands Project in northern Alberta.

Mr. Ebbern said the Sable Island and the oilsands are not alike.

"The reserves that we are taking away have a meaningful impact on production today, so losing Sable reserves and replacing it with oilsands isn't exactly a one to one replacement," he said. "It doesn't change the fact that Sable is continuing to be very disappointing."

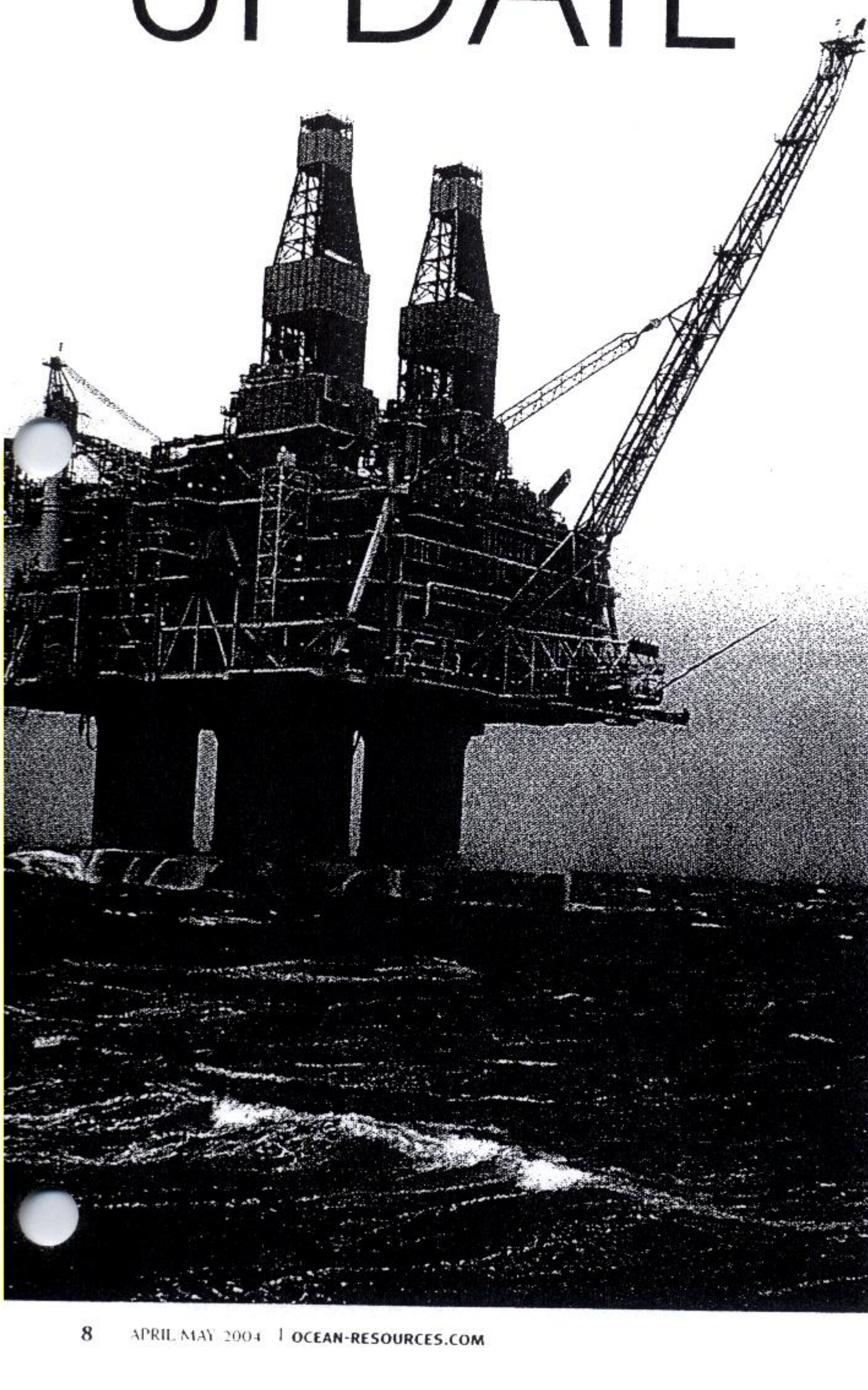
Mr. Ebbern said it is unlikely Shell Canada would have moved ahead with Sable, which started producing in 1999, if it had known how the field would play out.

Shell Canada's stock lost $1.57, or 2.5%, to close at $60.98 on the Toronto Stock Exchange.

Financial Post

NATIONAL POST

OFFSHORE ATLANTIC CANADA UPDATE



According to the Canadian Association of Petroleum Producers (CAPP), evidence of the importance of offshore Atlantic Canada to its member companies can be stated in hard numbers: 92 exploration licences covering 12.5 million hectares and $2.2 billion in work expenditure commitments over the next three to five years.† CAPP estimates that the Grand Banks, offshore Newfoundland and the Scotian Shelf, offshore Nova Scotia, have an ultimate potential of 63 trillion cubic feet (Tcf) of natural gas, with ultimate conventional oil resources for the two areas at 5.3 billion barrels.

With reserve potential, production infrastructure in place and proximity to North American markets, the potential of East Coast Canada is indeed attractive. However, with only three operating projects—Hibernia, Terra Nova and Sable—and one development underway—White Rose—Atlantic Canada's oil and gas industry is still relatively young and the region largely unexplored.

NEWFOUNDLAND & LABRADOR

HIBERNIA

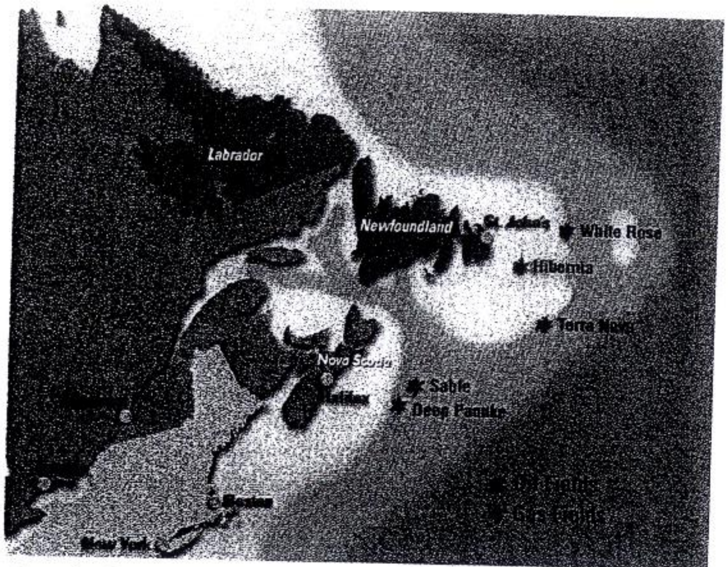
With estimated recoverable reserves of 865 million barrels of oil and 1.3 Tcf of natural gas, Hibernia is the fifth largest field ever discovered in Canada. Located some 315 kilometres east-southeast of St. John's, the field consists of two principle reservoirs—the Hibernia and Ben Nevis Avalon—that are located at average depths of 3,700 and 2,400 metres respectively.

The field is produced using a Gravity Base Structure (GBS) that has a 470,000-tonne concrete base embedded two metres into the ocean floor. Since its start-up in November 1997, year-to-date production at Hibernia has averaged more than 200,000 barrels per day and 2003 marked more than 230,000 barrels in a day. In 2003, six development wells were

Hibernia, the largest discovered oil development offshore Newfoundland.

drilled; four are completed and two are underway, quite an achievement considering Hibernia's wells are some of the longest, high-angle, extended-reach wells in the world.

Produced oil is stored within the platform's 1.3-million barrel internal storage cells and the crude oil is then transported to shore by shuttle tankers. Hibernia's crude is shipped directly to markets on the eastern seaboard of Canada and the United States, or offloaded at the trans-shipment facility at Whiffen Head, Placentia Bay.



Canadas East Coast offshore area.

TERRA NOVA

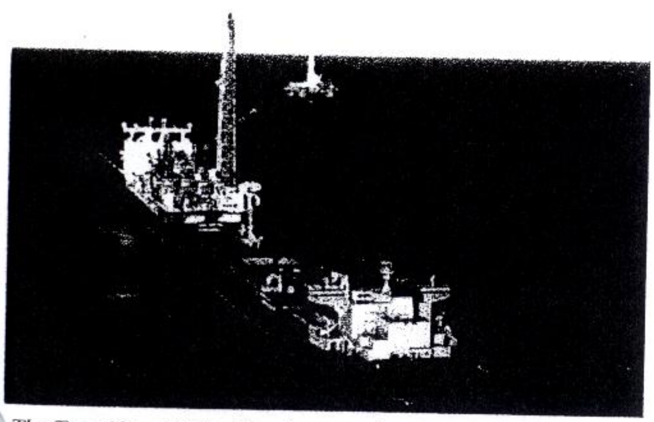
Discovered in 1984, Terra Nova is the second largest oil field off Canada's East Coast with recoverable reserves of 370 million barrels and operates just 35 kilometres southeast of Hibernia. With a start-up of January 2002, the project produced over 35 million barrels in its first year of production, and in 2003, the Canada-Newfoundland Offshore Petroleum Board approved a rate increase to a maximum of 180,000 barrels per day.

A strategic focus for Terra Nova now is to extend its production plateau period with development of the Far East portion of the field. In March, operator Petro-Canada downgraded reserve estimates for the untapped portion of the field from 100 million barrels to about 40 million barrels of oil. The downgrade was based on the results of three delineation wells drilled in 2003; older estimates were based on seismic mapping.

Located on the Grand Banks, an area famous for icebergs, Terra Nova is produced using a Floating-Production Storage and Offloading (FPSO) vessel because of its ability to disconnect and move to avoid unmanageable icebergs. The Terra Nova FPSO contains the first fully automated, quick-disconnectable turret and riser system on a FPSO and it is double-hulled to withstand the impact of a 100,000-tonne iceberg. The field also features the first application of open glory holes for protection of subsea equipment from scouring icebergs.

Each of the three 127,000-deadweight shuttle tankers used to transport the oil produced at Terra Nova carries up to 860,000 barrels of oil per trip, with a regular trip taking about four-and-a-half days. Once at the trans-shipment terminal, the oil is stored or offloaded into smaller vessels for delivery to markets primarily in Canada and the northeastern United States.

In March, Petro-Canada short-listed four consortia for an engineering, procurement and construction (EPC) services contract for the project. The scope of the contract includes front-end engineering studies as well as preliminary, conceptual and detailed engineering design services for facility modifications. Modifications to the Terra Nova FPSO may also be required to handle new production from the Far East fault block, as well as future satellites.


The Terra Nova FPSO offloading to a shuttle tanker, with the drilling unit Henry Goodrich in the background.

WHITE ROSE

White Rose, the third major offshore petroleum project for Newfoundland & Labrador, is moving steadily toward producing first oil in early 2006. Located in the Jeanne d'Arc Basin, 50 kilometres northeast of Terra Nova and 50 kilometres east of Hibernia, the project has estimated reserves of between 200-250 million barrels of oil, with peak production of 92,000 barrels oil per day and a life span of 15 years.

Operator Husky Energy has a 72.5 percent interest in the project, with Petro-Canada holding the remaining 27.5 percent. Sanctioning, tendering and procurement took place in 2002; 2003 was a year of construction and drilling, with more of the same planned for 2004. Recruitment and training for the operations phase of the project will also take place in 2004 through subcontractor Maersk.

The Floating-Production, Storage and Offloading (FPSO) vessel arrived in Marystown April 6, having departed the Samsung Heavy Industries shipyard in South Korea on February 12 for the 55-day, 14,000 nautical mile journey to Newfoundland. The double-hulled vessel is based on a Samsung shuttle-tanker design modified to serve as an FPSO and perform in conditions offshore Canada's East Coast. An ice-strengthened hull and a detachable mooring system have been incorporated into the design to ensure safe operation on the Grand Banks, and there is storage capacity or 940,000 barrels of oil, which is about 10 days of production capacity.

Fabrication of the subsea production system through Technip Offshore Services Canada is proceeding, with the first wellhead assembly completed in November 2003. The three glory holes, nine-metre deep depressions in the ocean floor excavated to protect the subsea system from iceberg scour, were completed at the end of August.

Development drilling for the White Rose field began in October 2003 and will continue through 2004. As of mid-march, the drilling pace of the development wells was some 40 days ahead of schedule. Under a two-year drilling contract to Husky, the Global Sante fe Grand Banks has now drilled eight of the 10 planned wells, the first of which spudded last October. The latest well is the first horizontal well to be drilled in the oil fields offshore Newfoundland.

EXPLORATION

In December 2003, joint-venture partners Imperial Oil Resources (25%), ExxonMobil Canada (25%) and Chevron Canada Resources (50%) acquired exploration rights for eight deepwater parcels offshore Newfoundland after proposing exploration spending of some $673 million, setting an offshore land sale record for the province. The parcels—estimated to contain several oil fields in the one-billion-barrel range—cover more than five million acres in the unexplored Orphan Basin, located about 155 miles north of Hibernia in water depths ranging from 6,500 to 8,200 feet.

The unprecedented bids are expected to quell speculation of a downturn in East Coast offshore oil exploration, partly sparked by ExxonMobil's 2002 decision to sell off all of its offshore Newfoundland exploration licences except one.

On March, 23, 2004, the Canada-Newfoundland Offshore Petroleum Board announced a 2004 Call for Bids. All five parcels in the Call are located in the Jeanne d'Arc Basin, which lies south of the Orphan Basin, and comprise a total of 270,256 hectares.

Geoscientific exploration programs conducted in 2003 saw the mapping of 5,374 kilometres of 2-D seismic and some 13,165 kilometres of 3-D seismic offshore Newfoundland and on the Labrador Shelf.

Husky Energy plans to drill one exploratory well offshore Newfoundland this year.

NOVA SCOTIA

SABLE

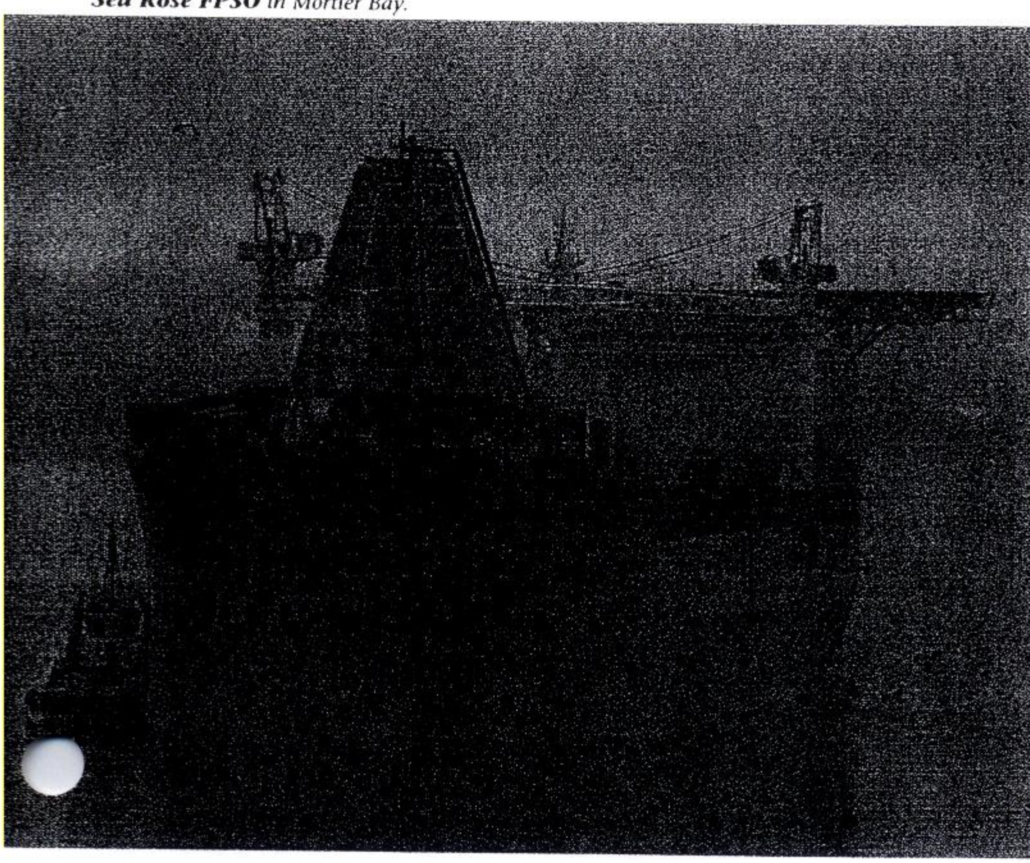
As the only development of its kind in Canada, the $3-billion Sable natural gas project has been a catalyst for awareness and growth in the East Coast petroleum industry. Operated by majority owner ExxonMobil Canada (50.8%), production from the three fields that make up Tier I—Thebaud, Venture and North Triumph—averages 500 million cubic feet (Mcf) of natural gas per day. Sable gas is transported to shore via a subsea pipeline to the Goldboro gas processing plant and Point Tupper liquids fractionation facility. It is then carried to markets in Nova Scotia, New Brunswick and the northeastern United States using the Maritimes and Northeast Pipeline.

In November 2003, Alma, the first of the Tier 2 fields, came on stream. The field is producing about 120 Mcf of natural gas and 3,000 barrels of condensate and natural gas liquids per day.

Fabrication work continues on the South Venture development, another of the Tier 2 fields, with a view to having gas flowing from that field by late 2005. It had been hoped that Glenelg, the third Tier 2 field, would come onstream between 2004-2007, but it has been found to be uneconomical as a stand-alone project.

In November 2003, ExxonMobil Canada awarded SaiWoo, a partnership between Italy's Saipem SpA and South Korea-based Daewoo Ship-building and

Grey skies and fog greeted the arrival of the ***Sea Rose FPSO*** *in Mortier Bay.*



Continued on page 12

PUBLIC VERSION

Marine Engineering, the Engineering, Procurement, Construction and Installation (EPCI) contract for a compression platform that will maintain production levels from the Sable fields. The 7,000-tonne compression deck—basically a giant pump required to push natural gas from Sable's five producing fields to shore—will sit on an eight-legged steel jacket and will be bridged-linked to the existing Thebaud processing platform. The offshore installation phase is slated for the summer of 2006.

In January, Shell Canada, a 31.3 percent partner in Sable, lowered its share of project reserves by 41 percent, to 430 Billion cubic feet (Bcf) down from 730 Bcf, its third negative reserve revision in three years. This news was followed by Pengrowth Energy Trust (8.4% interest) reducing its reserve estimates by 28 percent.

Sable represents about three percent of Canada's total output of natural gas and in 2003, produced 675 Bcf of gas.

Alma, the first of Sable's Tier 2 fields to begin production.

DEEP PANUKE

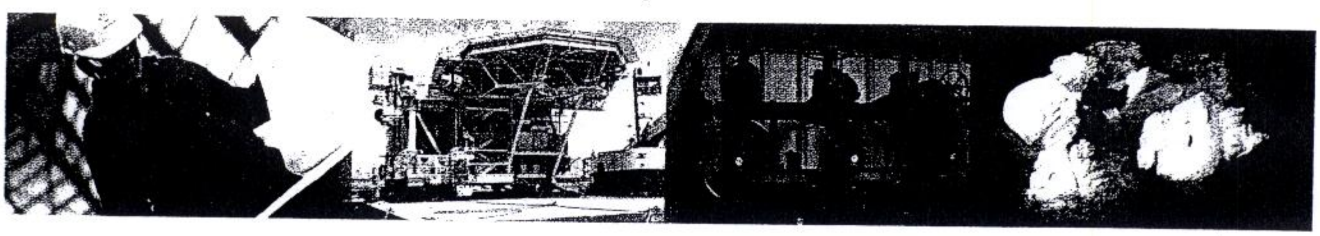
2003 was a year of review for EnCana and its proposed Deep Panuke project, as the Calgary-based company sought a more cost-effective path for its natural gas project offshore Nova Scotia. Having withdrawn its original development plan applications filed with regulators in December 2003, EnCana is now working on a more economical proposal that could take anywhere from six months to a year before the revised plan is ready. EnCana has been in discussions with partners in the Sable project over the sharing of Sable facilities in developing the field, and has said that it's too early to tell if a combined development will happen.

The new plan may include building a smaller offshore production platform that would generate lower volumes over a longer period than the 400 Mcf a day originally planned for eight to 12 years. Located 250 kilometres southeast of Halifax, Deep Panuke had called for the fabrication of three platforms—utilities/quarters, production and the wellhead—that would produce and process the slightly sour gas (it contains hydrogen sulphide) offshore before being transported ashore via a subsea pipeline. With estimated recoverable reserves approaching one trillion cubic feet, the project originally had an anticipated start-up date of 2006.

EXPLORATION

EnCana drilled two successful shallow water wells last summer at Margaree and MarCoh as part of their review of the Deep Panuke Project, and along with partners Shell Canada and Ocean Rig, are currently drilling the Weymouth exploration well near Sable Island. Progress has been slow and in mid-March the forecasted drilling time to complete the well—targeted depth for the well is 6,627 metres—was

Two Major Industry Events...



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extended, citing challenging geological conditions in the well.

EnCana has not announced plans to drill any new wells off Nova Scotia this year.

In March, Canadian Superior put its Mariner I-85 exploratory well on hold, despite encountering gas in multiple zones, blaming El Paso Oil & Gas Canada, an indirect subsidiary of El Paso Corporation and well operator with 50-percent interest, for the decision to abandon the well and not proceed with further testing. The Mariner I-85 well was drilled to the north of the eastern tip of Sable Island on the Scotian Shelf, only about 9 kilometres (5 1/2 miles) northwest of the Sable Offshore Energy Project's Venture natural gas producing field.

Canadian Superior says it still plans to drill another exploratory well near Mariner within three to six months.

The only other well scheduled for drilling offshore Nova Scotia this year is the Crimson exploratory well. Marathon Oil Canada plans to drill the Crimson deepwater well in April or May, about 350 kilometres southeast of Halifax, using the Deepwater Pathfinder, which is owned by Transocean of Houston.

Chevron Canada Resources has issued an EOI for a 3-D seismic survey on its Mahone offshore block, which is near an exploratory well it abandoned almost two years ago. If all goes as planned with corporate and regulatory approval, the company will map the Mahone block, located 275 kilometres southeast of Halifax, sometime between June and September.

As well, four 2-D seismic programs collected more than 15, 000 kilometres of data and three 3-D programs collected 4,765 square kilometres of data offshore Nova Scotia in 2003.

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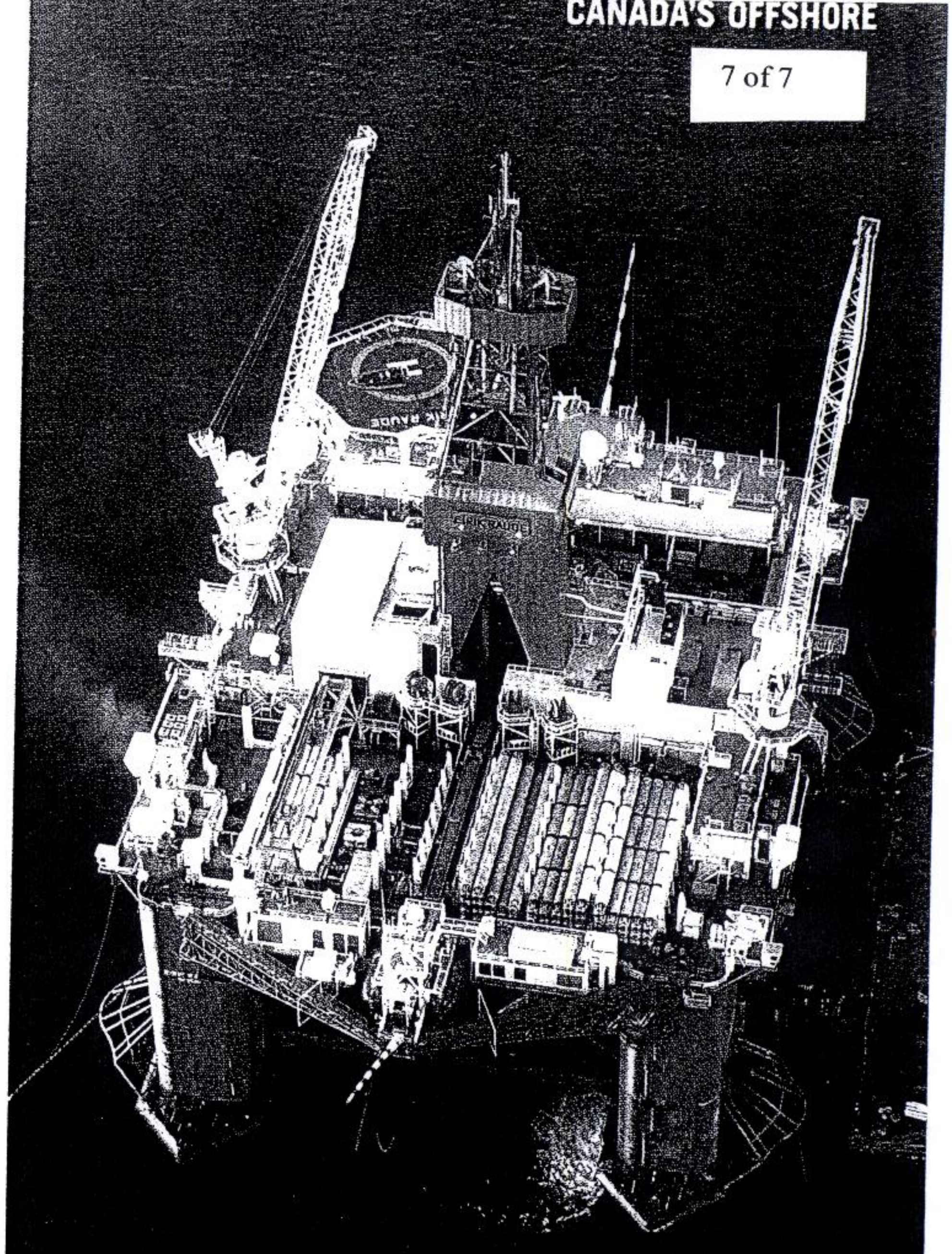
†*Submission to the Atlantic Energy Roundtable, November 2002.*



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Nova Sotia Average Carbonate Type Well

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