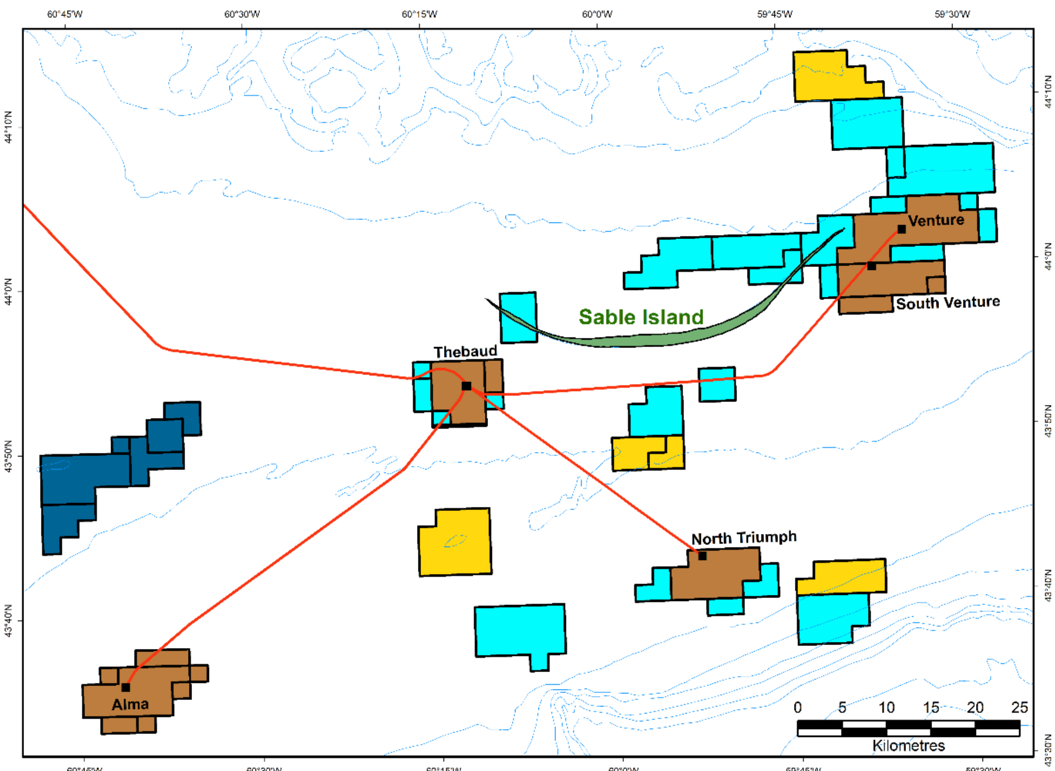
Sable Offshore Energy Project Resource Management Study



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Introduction

The purpose of this report is to describe the resource management regulatory oversight activities and analyses conducted by the Canada Nova Scotia Offshore Petroleum Board (CNSOPB) over the life of the Sable Offshore Energy Project (SOEP). This report will also summarize the regulatory oversight activities that were designed to prevent waste of the SOEP resources by ensuring that economic hydrocarbon recovery was maximized. This report will review expected and actual performance of the SOEP fields and summarize the key resource management learnings.

The SOEP Development Plan Application (DPA) was submitted, in June 1996, by Mobil Oil Canada Properties (Mobil) on behalf of the SOEP proponents that included Mobil, Shell Canada Limited (Shell), Petro-Canada, Imperial Oil Resources Limited (Imperial) and Nova Scotia Resources Limited (NSRL). In late 1999, Mobil merged with Exxon, and in 2002 ExxonMobil Canada Ltd. (ExxonMobil) became the operator of SOEP. For ease of reference, throughout this report, ExxonMobil will be noted as the operator of SOEP.

SOEP was originally designed to develop six natural gas and condensate fields located in the Sable Island area, offshore Nova Scotia, approximately 300 km southeast of Halifax. The initial fields scheduled for development (Tier 1 fields) included Venture, Thebaud, and North Triumph. Thebaud was the first SOEP field to be brought on production and started producing in December 1999 while Venture and North Triumph began production in February 2000. The second group of fields scheduled for development (Tier 2 fields) included Alma, South Venture, and Glenelg. Alma started production in November 2003 and South Venture began producing in December 2004. The Glenelg field was not developed as poor drilling results in 2003 indicated the field was no longer commercially viable.

Overview of SOEP Fields

Venture

The Venture field was discovered in 1979 by the Venture D-23 (D-23) exploration well. Four delineation wells were subsequently drilled: Venture B-13 (B-13), Venture B-43 (B-43), Venture B-52 (B-52) and Venture H-22 (H-22). The following table provides a listing of basic well data for all wells drilled in the Venture field before production began.

Table 1: Venture Exploration and Delineation Wells

Well Name	Year Drilled	Total Depth (metres)	Water Depth (metres)
Venture D-23	1979	4945	20.1
Venture B-13	1981	5368	24.7
Venture B-43	1982	5872	20.4
Venture B-52	1983	5960	19.5
Venture H-22	1984	5944	22.0

The B-43 well was drilled on a structural high west of the D-23 discovery well and flowed gas from nine sandstone reservoirs. The H-22 well encountered tighter sandstones in the deeper overpressured section and provided the southerly limit to reservoir development in these horizons. 3D seismic interpretation was used to define the Venture structure. Figure 1 shows the location of the Venture exploration and delineation wells on a top Sand 6 depth structure map.

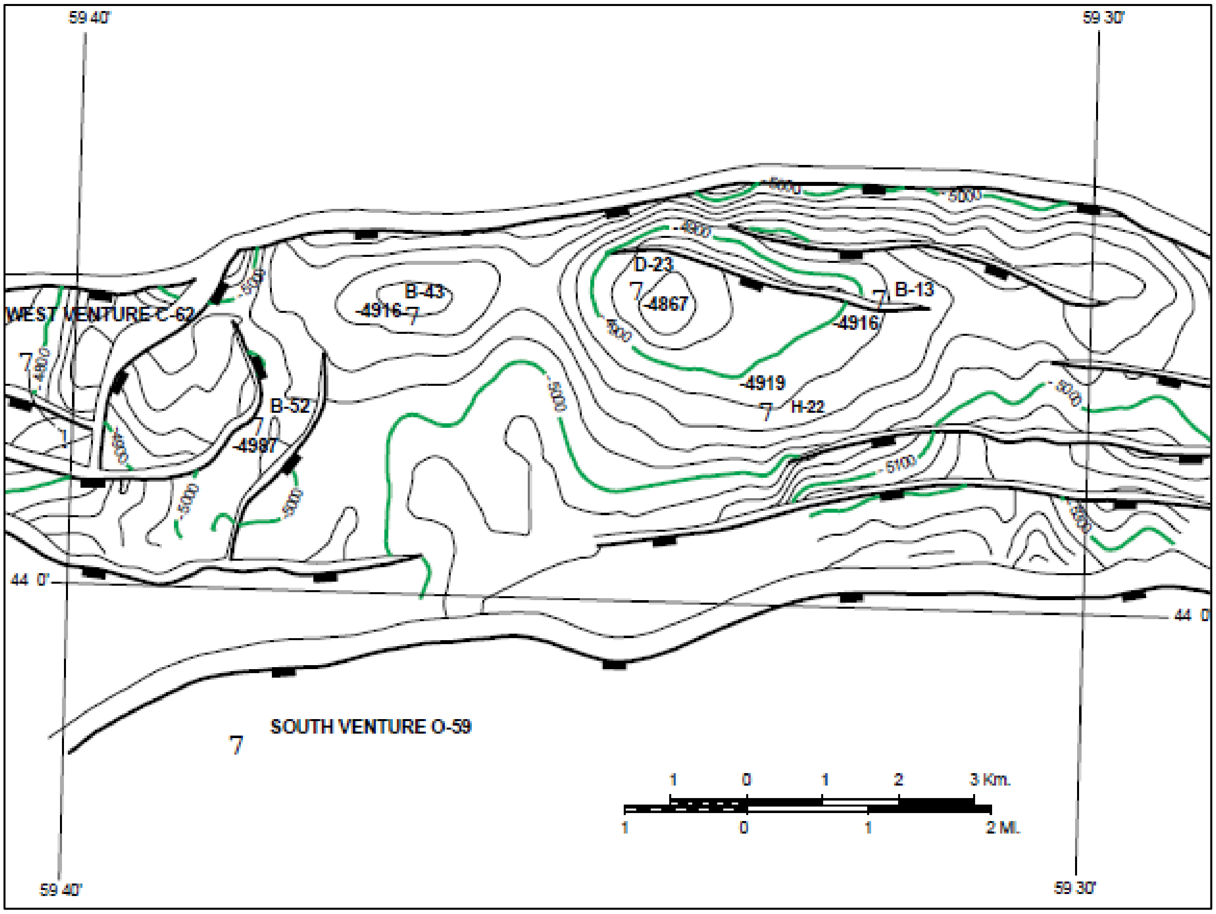

Figure 1: Venture Top Sand 6 Depth Structure Map, 20 m contour interval (SOEP DPA Volume 2)

It was determined from the well results that most of the Venture gas resource was contained in the deeper overpressured sandstone reservoirs. Pressure versus depth data indicated the deeper reservoir sands were located within a stepped overpressure system.

The four largest Venture sandstone reservoirs were the following: Sand 2 (hydropressured), and the overpressured Sands 3, 5 and 6 Upper. Figure 2 is a schematic cross-section of the Venture field.

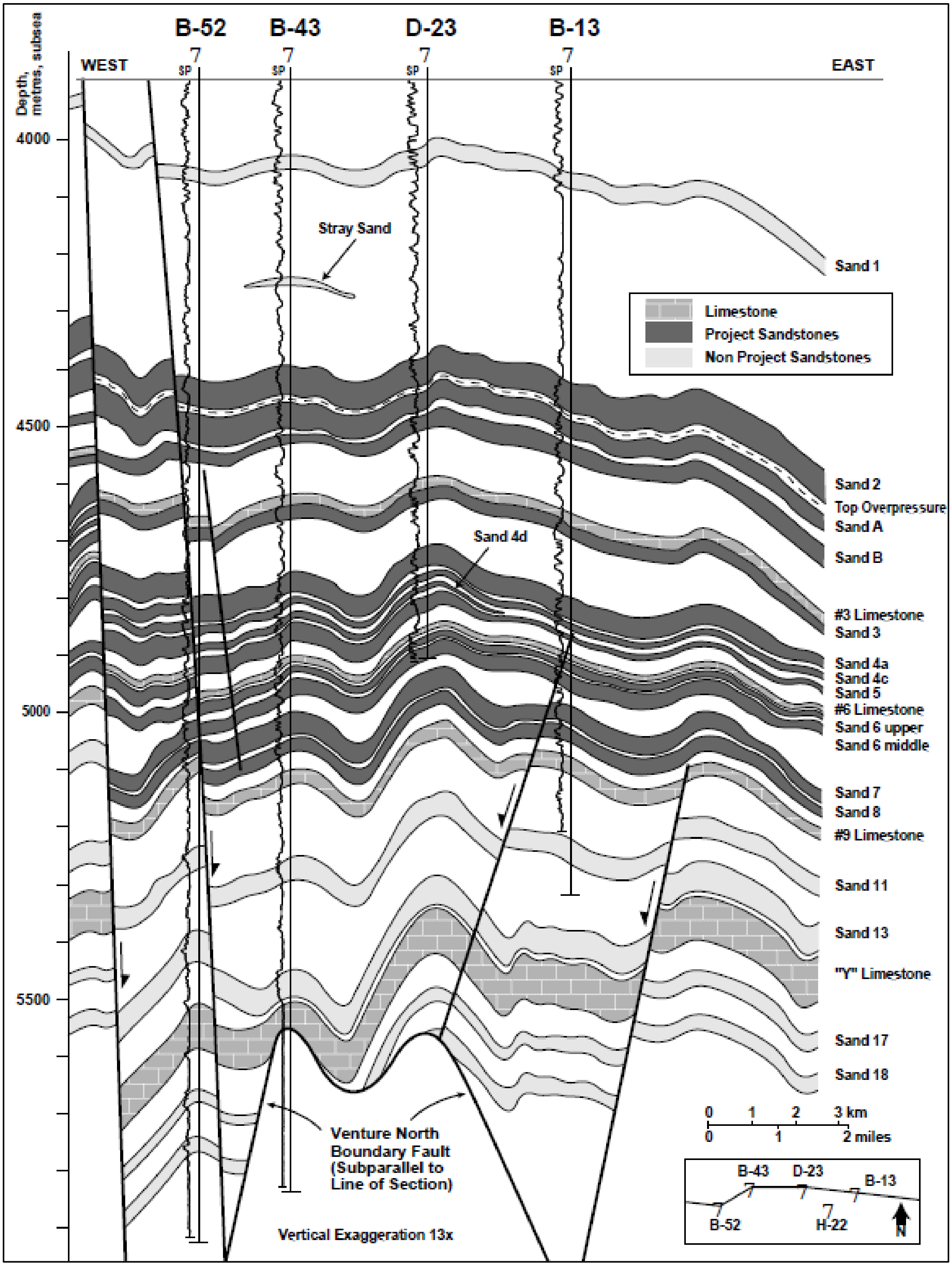

Figure 2: Venture Schematic Structural Cross-Section (SOEP DPA Volume 2)

Sand 2 is a significant reservoir in the Venture field. Reservoir development in Sand 2 varies across the field as porosity is poorly developed to the west, near B-52 and B-43, and to the south at H-22, it has completely shaled out. The Sand 2 reservoir was best developed to the east in the D-23 and B-13 wells. Sand 3 was the shallowest of the overpressured major sands at Venture and reservoir development at this sand was generally consistent across the field. Reservoir development in Sand 5 was observed to be quite variable across the field. This sand was shown to be poorly developed in the southern H-22 well location where it had almost completely shaled out. The upper part of Sand 5 was determined to be faulted out at B-13. Reservoir development in Sand 6 Upper was consistent across the field. The Sand 6 Upper reservoir was best developed at B-52, B-43, and D-23. Sand 6 Upper was also well developed to the south at H-22.

The main predevelopment uncertainties included the degree of compartmentalization and faulting, reservoir quality variations across the field and the elevation of free water level. Subsequently acquired 3D seismic data helped address these uncertainties.

Thebaud

The Thebaud field was discovered in 1972 by the Thebaud P-84 (P-84) exploration well and was subsequently delineated by three additional wells, Thebaud I-94 (I-94), Thebaud I-93 (I-93) and Thebaud C-74 (C-74), which were drilled in 1978, 1985 and 1986, respectively. The following table shows a summary of the exploration and delineation wells drilled at Thebaud.

Table 2: Thebaud Exploration and Delineation Wells

Well Name	Year Drilled	Total Depth (metres)	Water Depth (metres)
Thebaud P-84	1972	4115	25.9
Thebaud I-94	1978	3692	28.0
Thebaud I-93	1985	5166	30.0
Thebaud C-74	1986	5150	31.0

The formation evaluation conducted by ExxonMobil indicated that most of the Thebaud gas resources were contained in the deeper overpressured Thebaud sands. The shallower hydropressured interval, in the above wells, included a series of thin gas sands with limited areal extent that were determined to be uneconomic accumulations.

The A Sand was the first overpressured Thebaud reservoir that was found to be gas bearing in all four Thebaud exploration and delineation wells, confirming the presence of a significant gas accumulation. The following figure shows a depth structure map of the top of the Thebaud A Sand and includes the well locations.

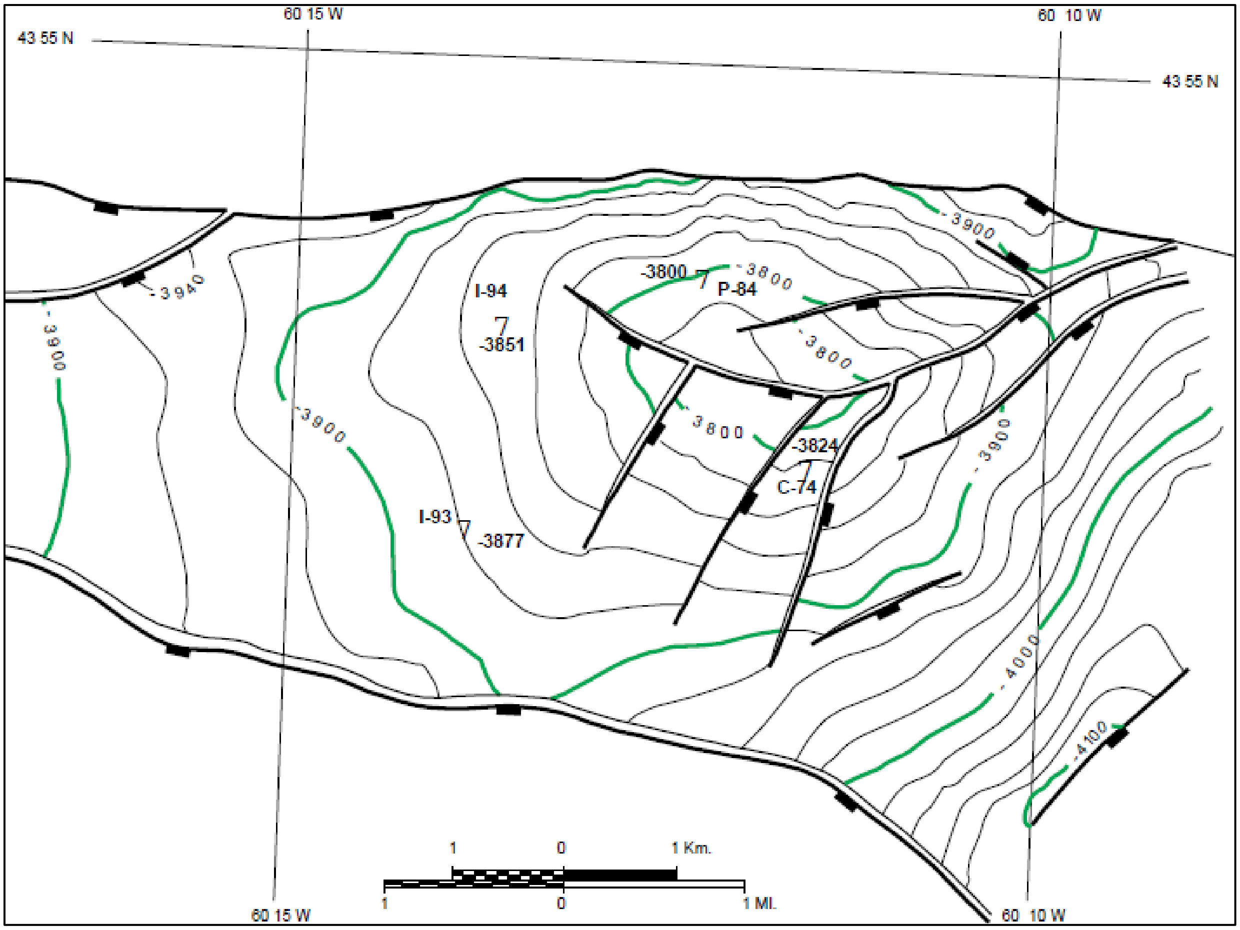

Figure 3: Thebaud Top A Sand Depth Structure Map, 20 m contour interval (SOEP DPA Volume 2)

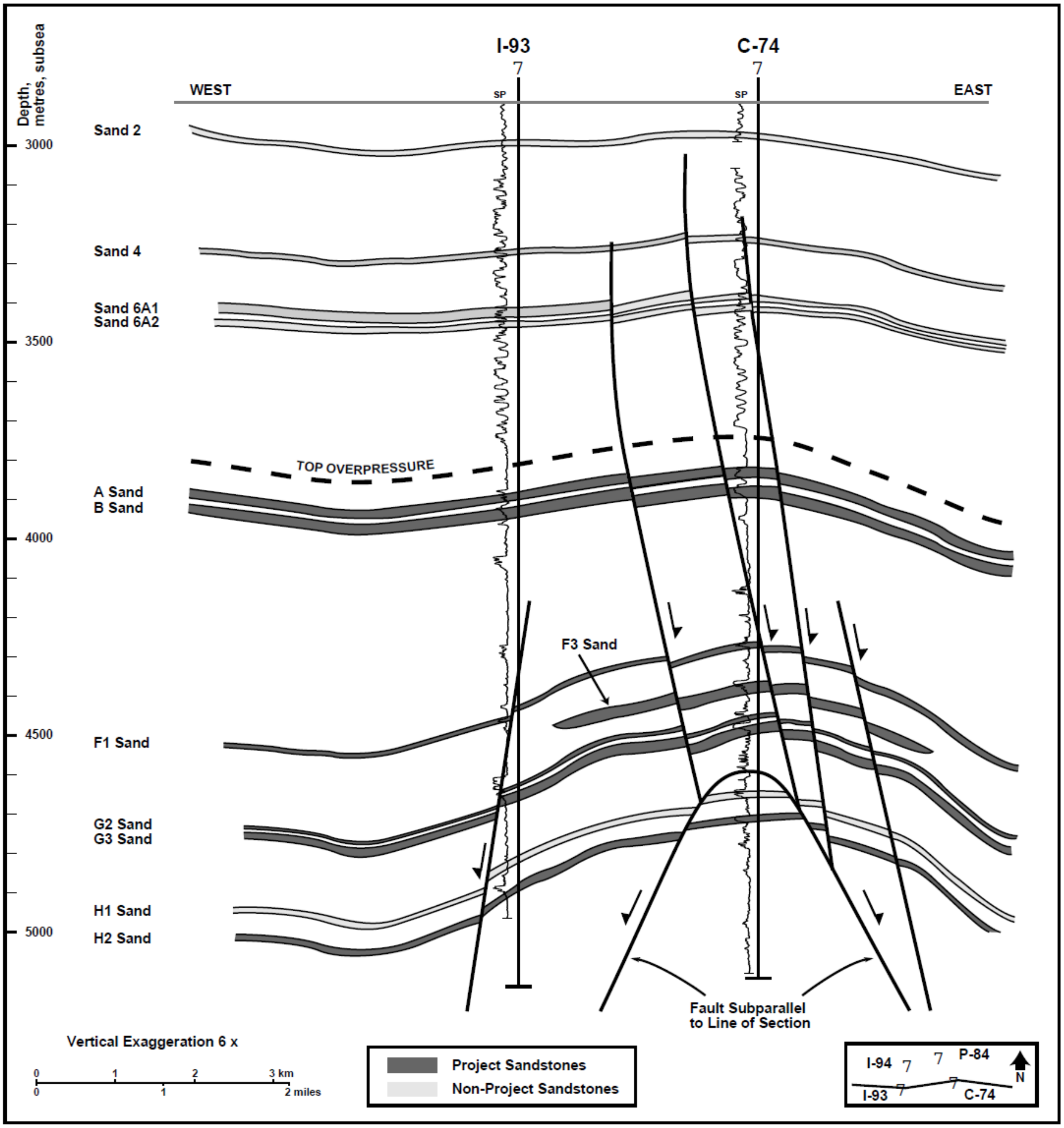

Figure 4: Thebaud Schematic Structural Cross-Section (SOEP DPA Volume 2)

Some of the key pre-development uncertainties included the extent of fault compartmentalization and reservoir continuity and the impact of these factors on the number of wells required to efficiently produce the sands.

North Triumph

The North Triumph (NT) gas field is located approximately 200 km off the coast of Nova Scotia. Two pre-development wells were drilled, North Triumph G-43 (G-43 – discovery well) and North Triumph B-52 (B-52 - delineation well).

Table 3: North Triumph Exploration and Delineation Wells

Well I.D.	Year Drilled	Total Depth (metres)	Water Depth (metres)
North Triumph G-43	1985	4504	74.0
North Triumph B-52	1986	3960	81.0

Shell was the operator of the G-43 discovery well. The Upper Missisauga was the primary zone of interest in the well and this interval tested gas at rates between 991 E3m3/d (35 MMscf/d) to 1,047 E3m3/d (37 MMscf/d) with no free water production. The other sands in the Missisauga and Lower Logan Canyon formations penetrated by this well were either tight or wet.

The other well drilled in NT was the B-52 delineation well B-52 which produced gas and water during testing. The following figure is a depth structure on the top of the Missisauga Formation at North Triumph.

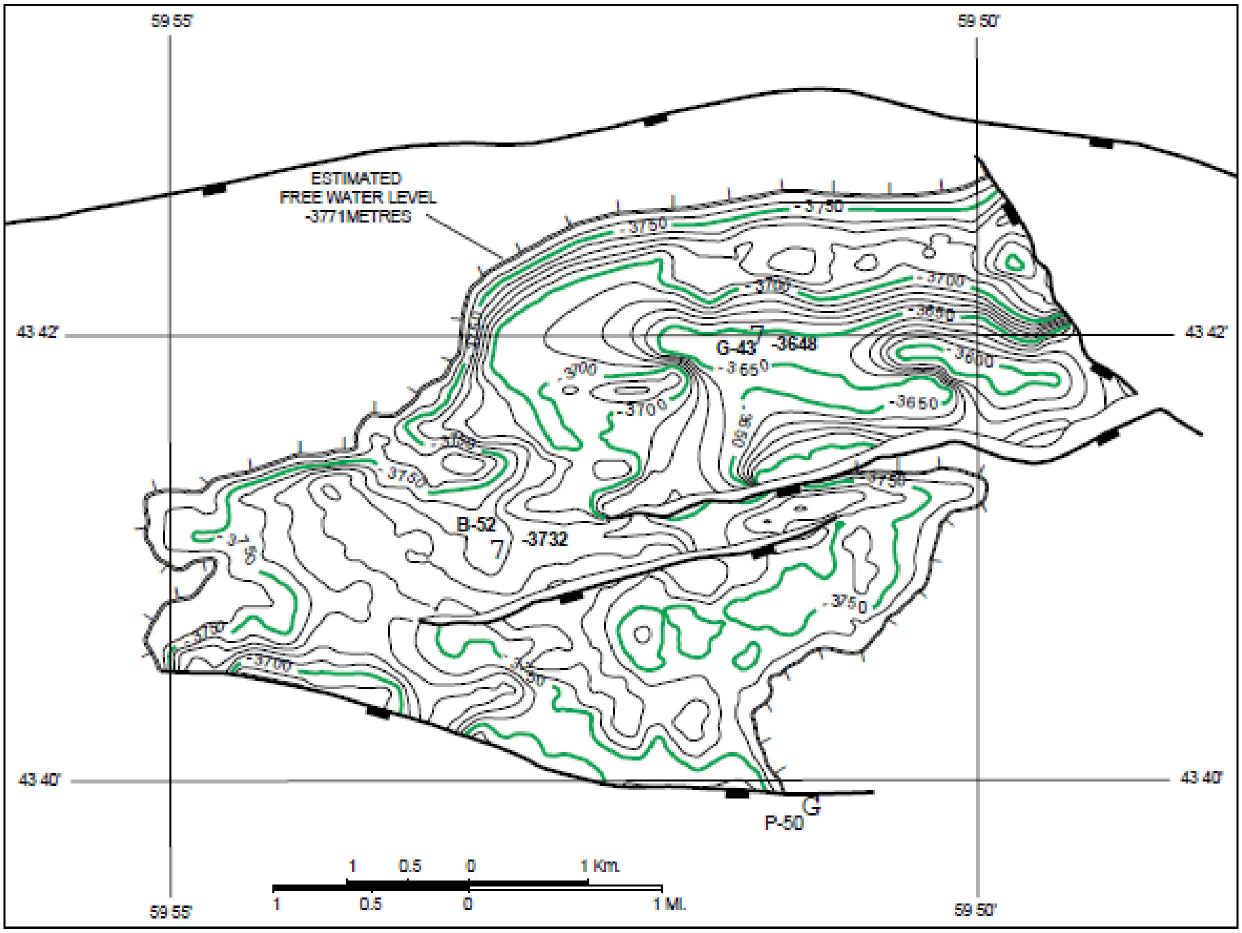

Figure 5: North Triumph Top Missisauga Depth Structure Map, 10 m contour interval (SOEP DPA Volume 2)

The North Triumph structure is a rollover anticline bounded to the north and south by major listric growth faults. The field can be divided into three polygons as follows: central, south and northeast. The majority of reserves are in the central polygon, a crestally faulted E-W trending anticlinal feature with a diapiric salt core. Despite the existence of crestal faults, the reservoir was not found to be compartmentalized.

The North Triumph field consisted of a large single gas pool (A Sand) located in the uppermost part of the Missisauga Formation. Log correlation indicated there was good stratigraphic continuity across the NT structure. Pressure data also indicated there was good reservoir continuity across the field. The following figure displays a structural cross section of the North Triumph A Sand.

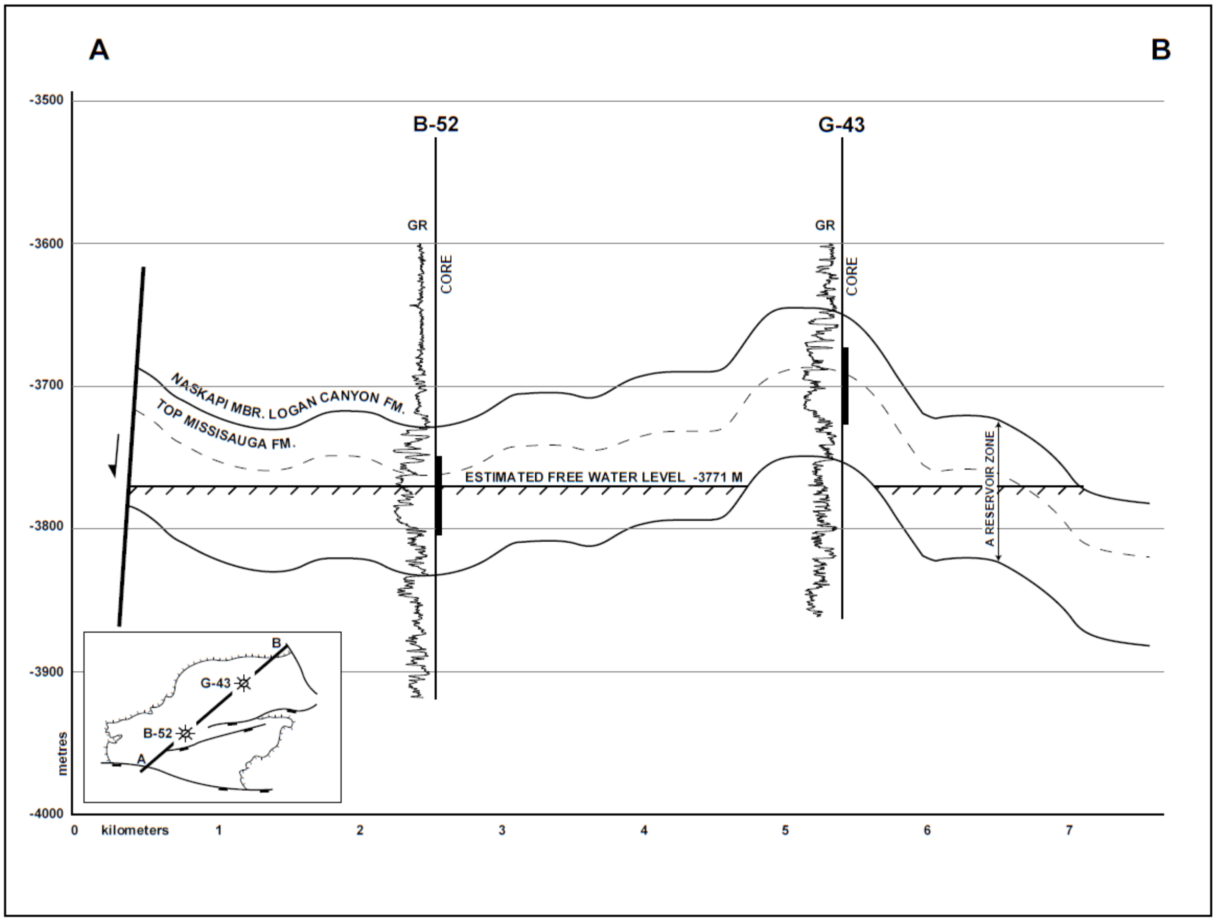

Figure 6: North Triumph Schematic Structural Cross-Section of the Upper Missisauga Formation (SOEP DPA Volume 2)

As noted above, well and pressure data indicated the North Triumph gas pool had good reservoir continuity across the field which should result in high recovery factors (e.g. 80% or higher).

South Venture

The South Venture gas field is located approximately 5 km south of the Venture field. The field was discovered in 1983 by the South Venture O-59 (O-59) exploration well. Multiple stacked hydropressured and overpressured sandstone gas reservoirs were encountered which tested at rates up to 509 E3m3/d (18.0 MMscf/d).

Table 4: South Venture Exploration Well

Well I.D.	Year Drilled	Total Depth (metres)	Water Depth (metres)
South Venture O-59	1983	6,176	24.0

The following figure displays the South Venture Sand 2 depth structure map included in the DPA.

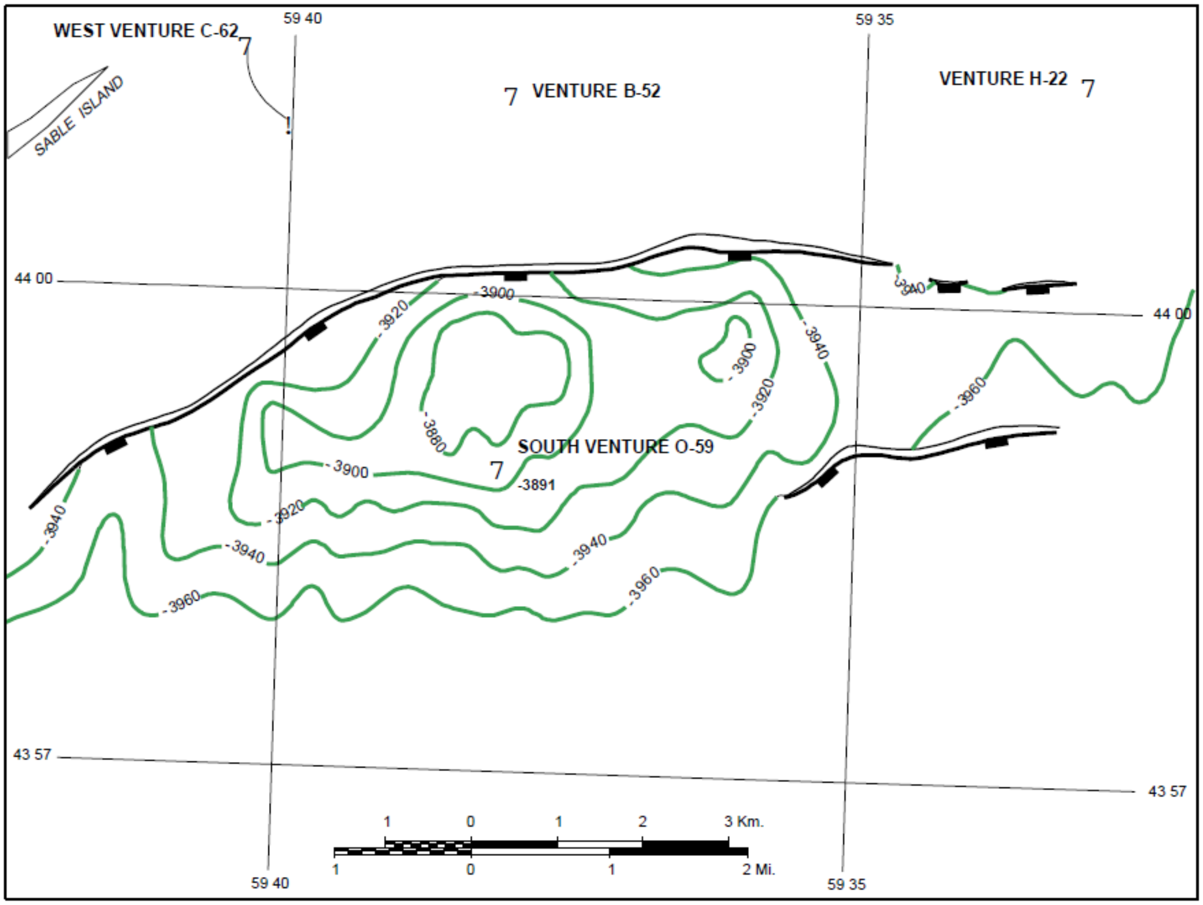

Figure 7: South Venture Top Sand 2 Depth Structure Map, 20 m contour interval (SOEP DPA Volume 2)

Two other sandstone reservoirs, Sands 7 and 8, also tested gas in the O-59 well. These lower porosity zones showed significant pressure drawdown during well testing.

Based on the DPA, reservoir sandstones in the South Venture hydropressured section were interpreted to be younger than comparable intervals in the Venture Field located to the north. Seismic interpretation suggested that there should be good continuity of the South Venture reservoir sandstones throughout the shallower hydropressured section of the field. The following figure is a schematic cross-section of the South Venture field.

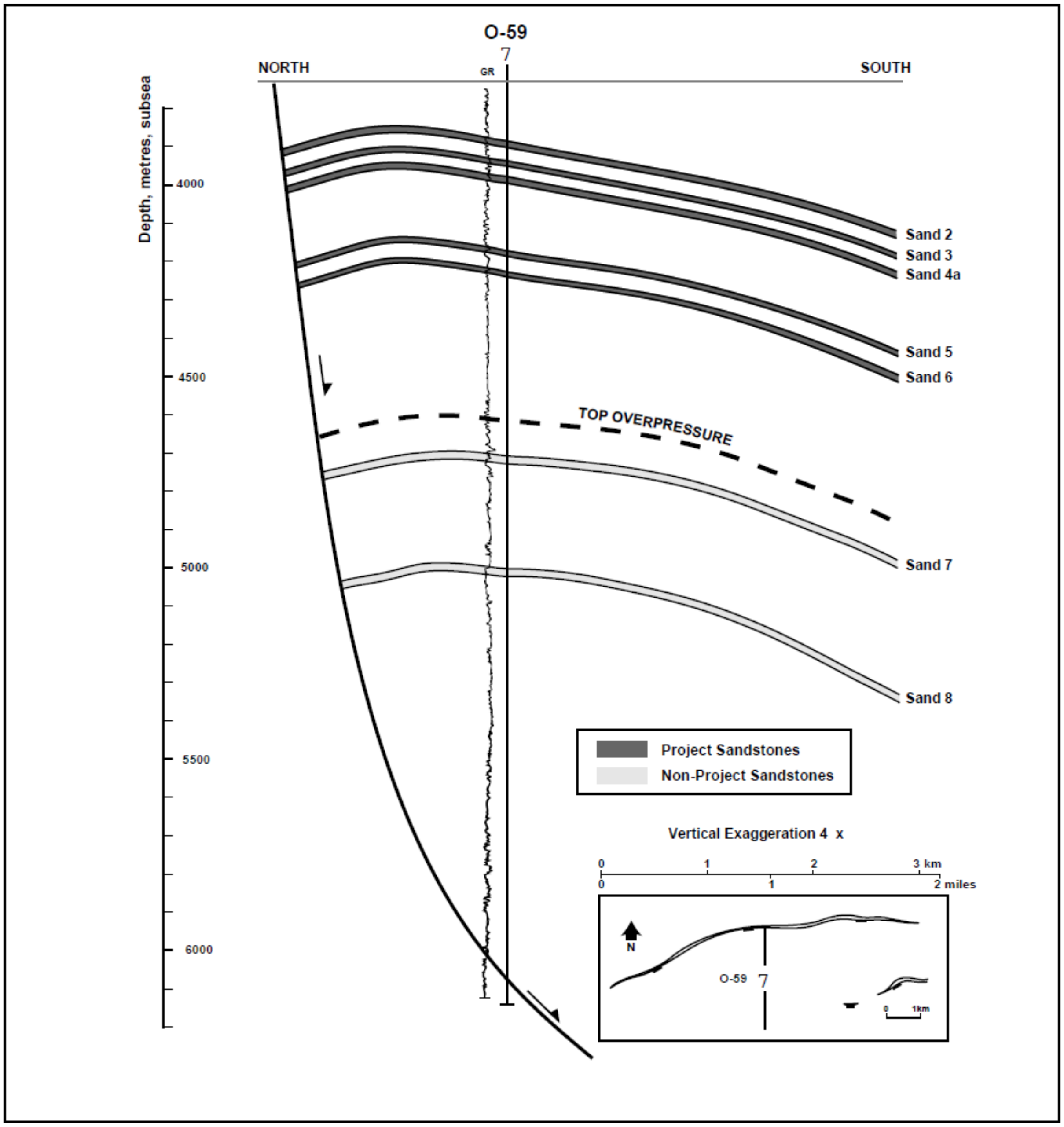

Figure 8: South Venture Schematic Structural Cross-Section (SOEP DPA Volume 2)

Pre-development uncertainties for the South Venture field included the extent of reservoir continuity across the field and the potential impacts of water production on overall recovery.

Alma

The Alma field is located 60 km southwest of Sable Island and was discovered in 1984 by the Alma F-67 (F-67) exploration well. This well encountered stacked, hydropressured, net gas pay in a number of separate pools in the uppermost 200 metres of the Missisauga Formation. Gas rates of up to 842 E3m3/d (29.7 MMscf/d) were measured during testing of the F-67 well. The Alma K-85 (K-85) delineation well, drilled in 1985, also encountered significant gas pay in the Upper Missisauga Formation.

Table 5: Alma Exploration and Delineation Wells

Well I.D.	Year Drilled	Total Depth (metres)	Water Depth (metres)
Alma F-67	1984	5,054	68.0
Alma K-85	1985	3,602	68.0

The following figure is a depth structure map on the top of the Missisauga Formation (A pool) at Alma.

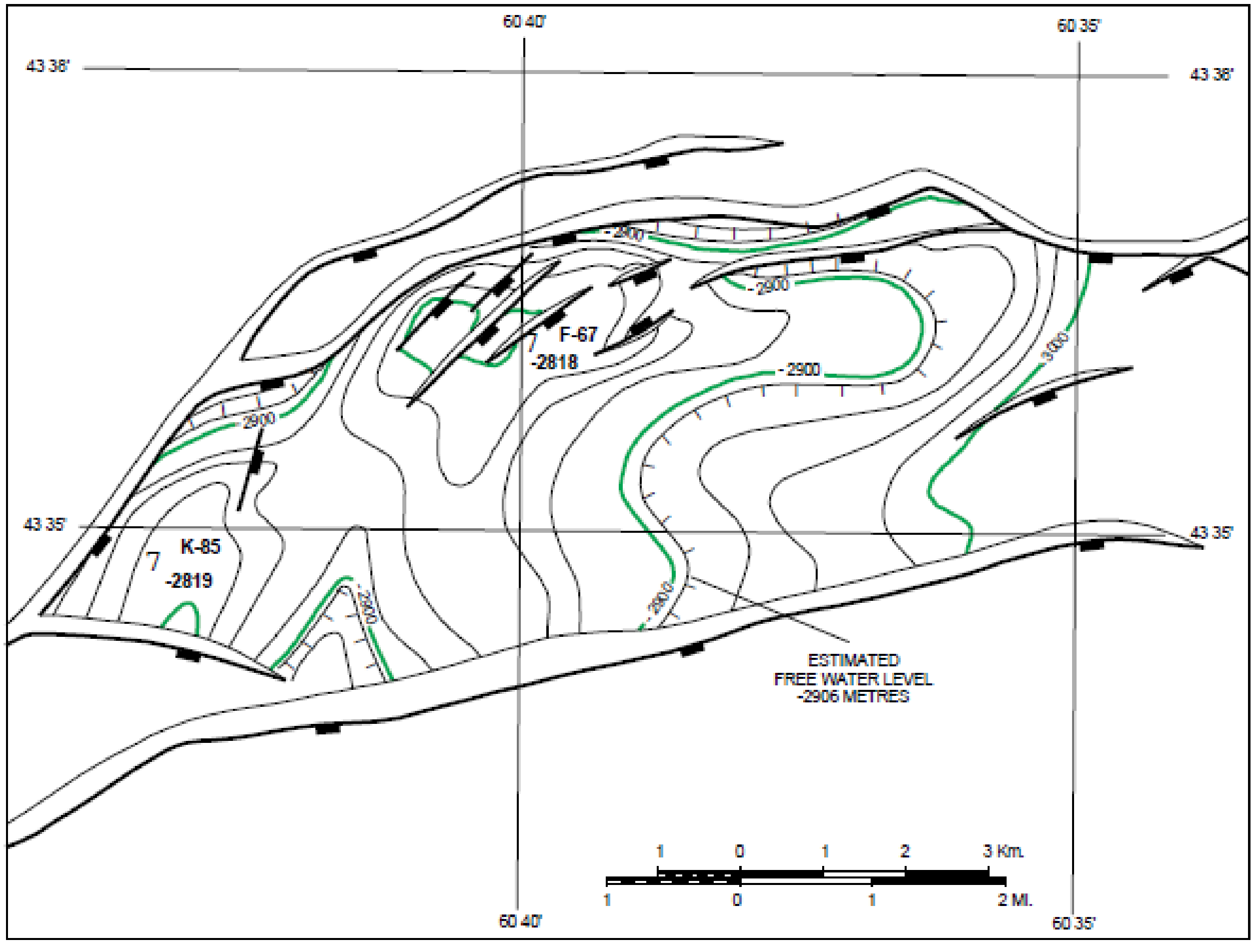

Figure 9: Alma Top Missisauga (A Pool), Depth Structure Map, 25 m contour interval (SOEP DPA Volume 2)

The Alma structure is a rollover anticline bound to the north and south by major listric faults. The field has two lobes, an F-67 lobe in the central portion and the K-85 lobe located to the southwest. Five separate Upper Missisauga gas pools were identified with Sands A, B and C containing the largest gas reserves. Some of the key pre-development uncertainties included the number of production wells needed, given the field configuration, and the potential impact of water on overall gas recovery. The following figure is a structural cross-section across the Alma field.

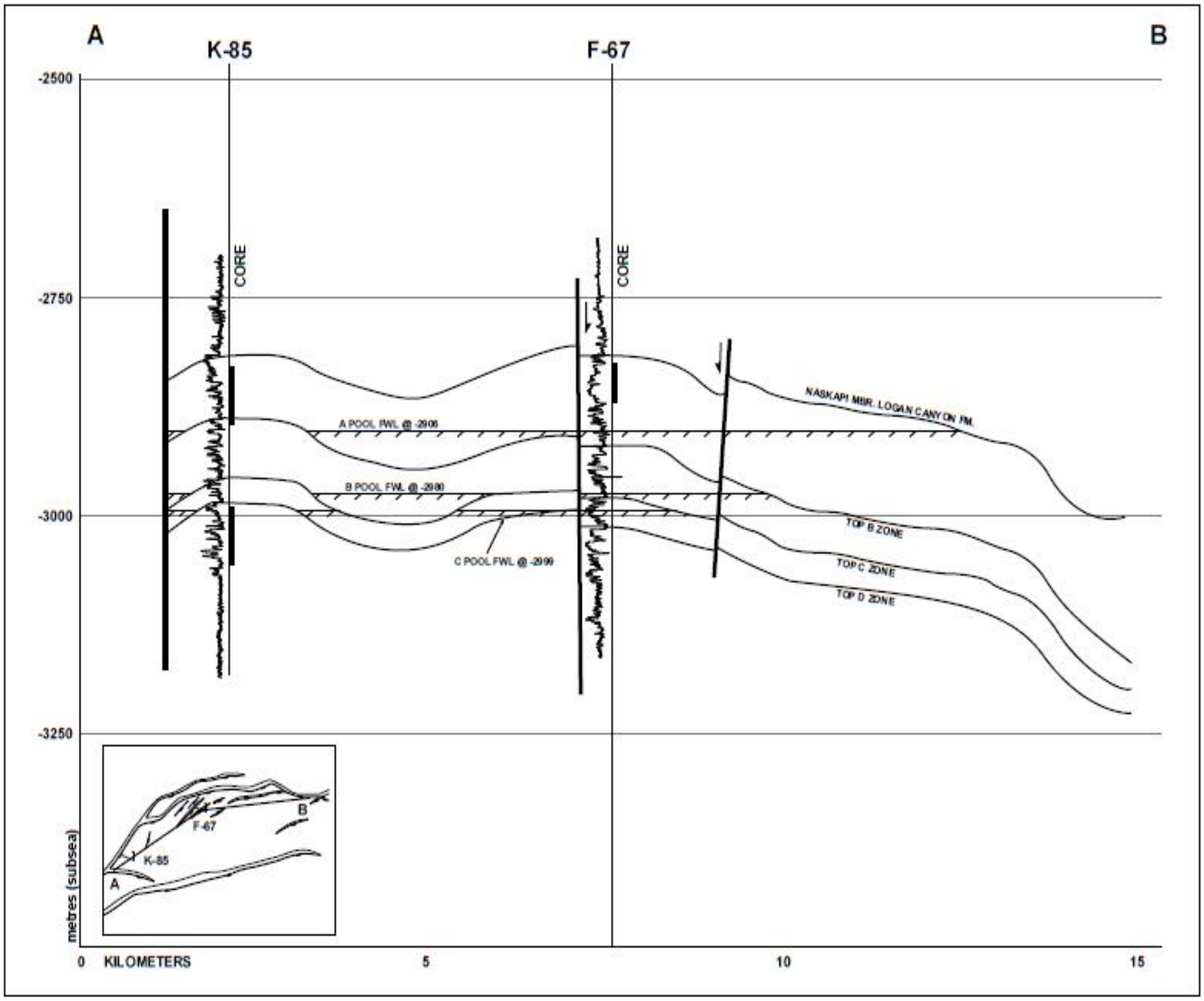

Figure 10: Alma Schematic Structural Cross-Section (SOEP DPA Volume 2)

Reserve Estimates

This section provides an overview of the in-place and recoverable gas and condensate volumes included in the SOEP DPA.

The following figure displays the production forecasts, included in the DPA, for each SOEP field. Production was planned to begin from Thebaud, Venture and North Triumph, with South Venture, Alma and Glenelg coming on production later in the project.

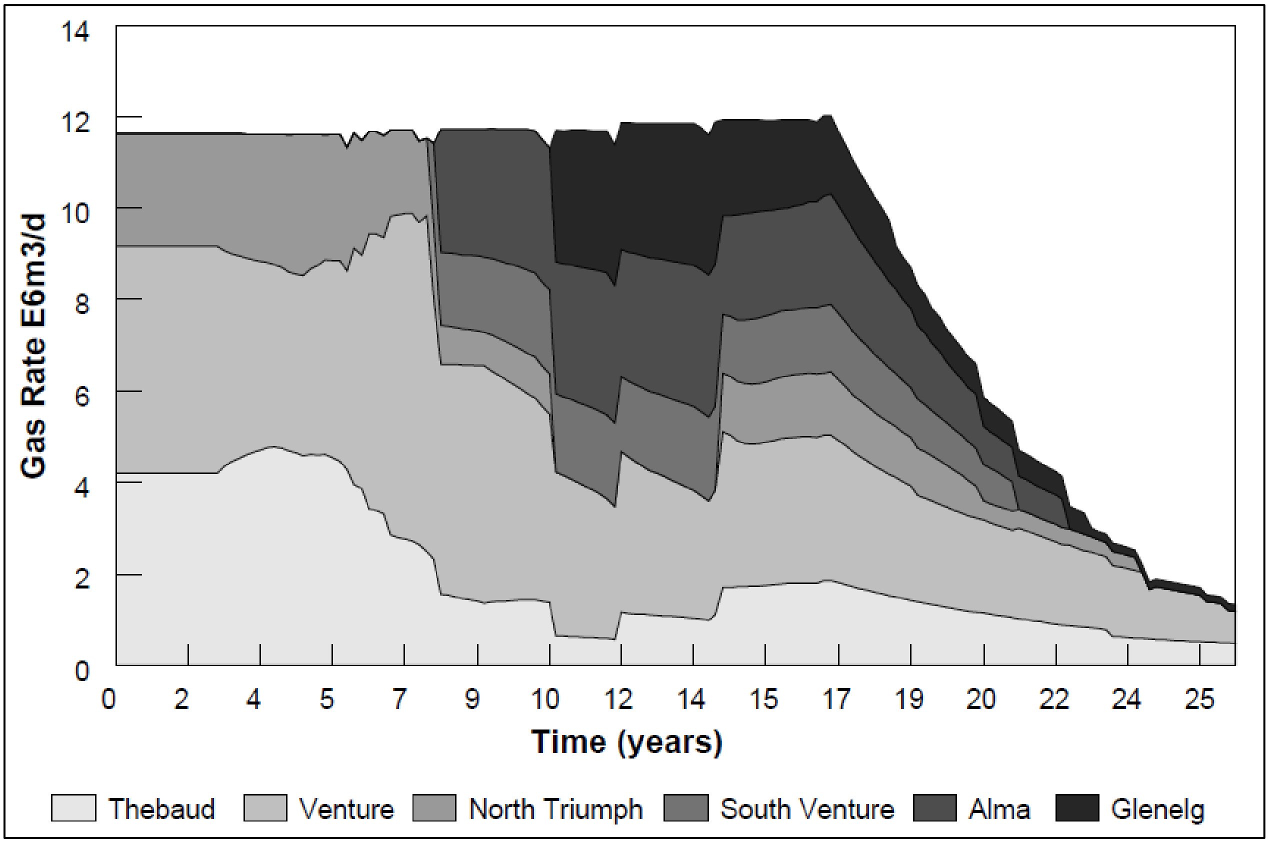

Figure 11: Raw Gas Production Forecast (SOEP DPA Volume 2)

The table on the following page lists the probabilistic estimates for in-place and recoverable gas and condensate volumes included in the SOEP DPA.

Table 6: SOEP Probabilistic Reserves (SOEP DPA Volume 2)

Field	**OGIP Mean Value E9m3 (Bcf)**	**P90 Raw Recoverable E9m3 (Bcf)**	**P50 Raw Recoverable E9m3 (Bcf)**	**P10 Raw Recoverable E9m3 (Bcf)**	**Mean Raw Recoverable E9m3 (Bcf)**	**Mean Condensate Recoverable E6m3 (MMBbls)**
Thebaud	26.0 (918.2)	6.4 (226.0)	14.4 (508.5)	30.3 (1070.0)	16.9 (596.8)	2.4 (15.1)
Venture	49.4 (1744.5)	11.9 (420.2)	27.1 (957.0)	58.6 (2069.4)	32.2 (1137.1)	6.2 (39.0)
NT	15.2 (536.8)	4.0 (141.3)	9.1 (321.4)	17.3 (611.0)	10.2 (360.2)	0.4 (2.5)
SV	11.3 (399.1)	2.0 (70.6)	7.2 (254.3)	15.5 (547.4)	7.8 (275.5)	1.4 (8.8)
Alma	15.0 (529.7)	4.8 (169.5)	9.4 (332.0)	10.9 (385.0)	9.4 (332.0)	1.0 (6.3)
Glenelg	12.4 (437.9)	3.2 (113.0)	7.3 (257.8)	12.5 (441.4)	7.8 (275.5)	0.5 (3.1)
Total	**129.3 (4566.2)**	**32.3 (1140.7)**	**74.5 (2631.0)**	**145.1 (5124.2)**	**84.3 (2977.0)**	**11.9 (74.8)**

CNSOPB Seismic Interpretation

This section describes the CNSOPB's seismic interpretation studies of the five developed SOEP fields (Venture, Thebaud, North Triumph, Alma and South Venture). These studies were completed as part of the CNSOPB's resource management and regulatory oversight of the project.

Venture

The Venture structure is an elongate, east-west trending rollover anticline. The main north bounding fault is one of series of faults with basinward throw that are rooted in Triassic-Jurassic aged allochthonous salt of the Sable Shelf Canopy (Kendell, 2012). Minor listric faults are also present, and while the seismic data quality is generally good, it is probable that other small-offset faults are present that have not been adequately imaged and therefore do not appear on the time-structure map of the 2 Sand.

Seven development (production) wells were drilled in the Venture field as part of the SOEP. These wells are as follows: Venture 1 (V1), Venture 2 (V2), Venture 3 (V3), Venture 4 (V4), Venture 5 (V5), Venture 6 (V6) and Venture 7 (V7). The exploration delineation and development wells drilled in the Venture field are displayed on the 2 Sand time-structure map below.

The time-structure map of the 2 Sand within the Venture structure displays three structural highs, two of which are gas-charged. The westernmost highpoint northwest of B-52 is the probable high-side spill point near the convergence of the main regional fault and a second curvilinear listric fault. Venture B-43, V5 and V6 all intersect the gas-charged central crest. To the east, across a structurally lower saddle, Venture D-23 and the V1, V2 and V3 wells intersect the primary eastern crest of the structure. V4 and V7 are drilled into two smaller scale linear highs that are parallel to the main north-bounding fault, while H-22 and B-13 are located near the south-southeastern dip closed limit of the Venture structure.

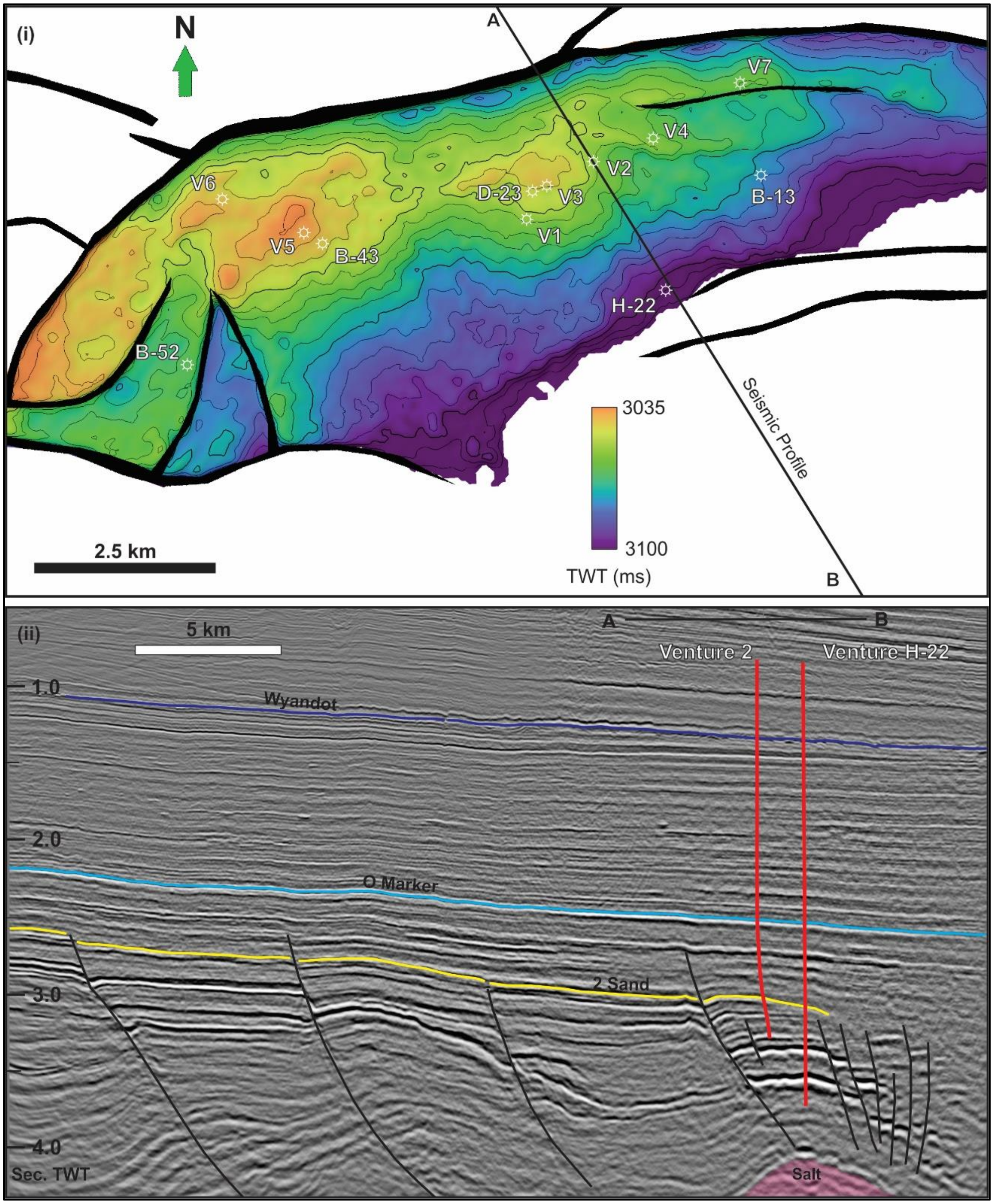

Figure 12: (i) Time-structure map of the Venture 2 Sand displaying the exploration, delineation and production wells. Location of seismic section A-B is shown and well symbols are posted at their downhole intersection with the surface (ii) Dip seismic section A-B intersects the Venture 2 and Venture H-22 wells (red lines denote borehole paths). The 2 Sand is highlighted in yellow on the seismic section, and coinciding seismic coverage of above structure map is noted by the length of the A-B line.

Thebaud

The Thebaud structure is a broad, sub-circular, rollover anticline centered between two east-west trending salt-detachment faults. These two main boundary faults are detaching along the southern edge of an allochthonous salt body that is a component of the Sable Shelf Canopy. The time-structure map of the A Sand horizon illustrates other minor-offset listric faults are present at the crest of structure. Thebaud I-93 is located southeast of the structure's crest near the western limit of the dip closure while all remaining exploration and production wells intersect separate fault compartments at the crest.

Five development (production) wells were drilled in the Thebaud field as part of the SOEP. These wells are as follows: Thebaud (T1), Thebaud 2 (T2), Thebaud 3 (T3), Thebaud 5 (T5) and Thebaud 6 (T6). The exploration delineation and development wells drilled in the Thebaud field are displayed on the A Sand time-structure map below.

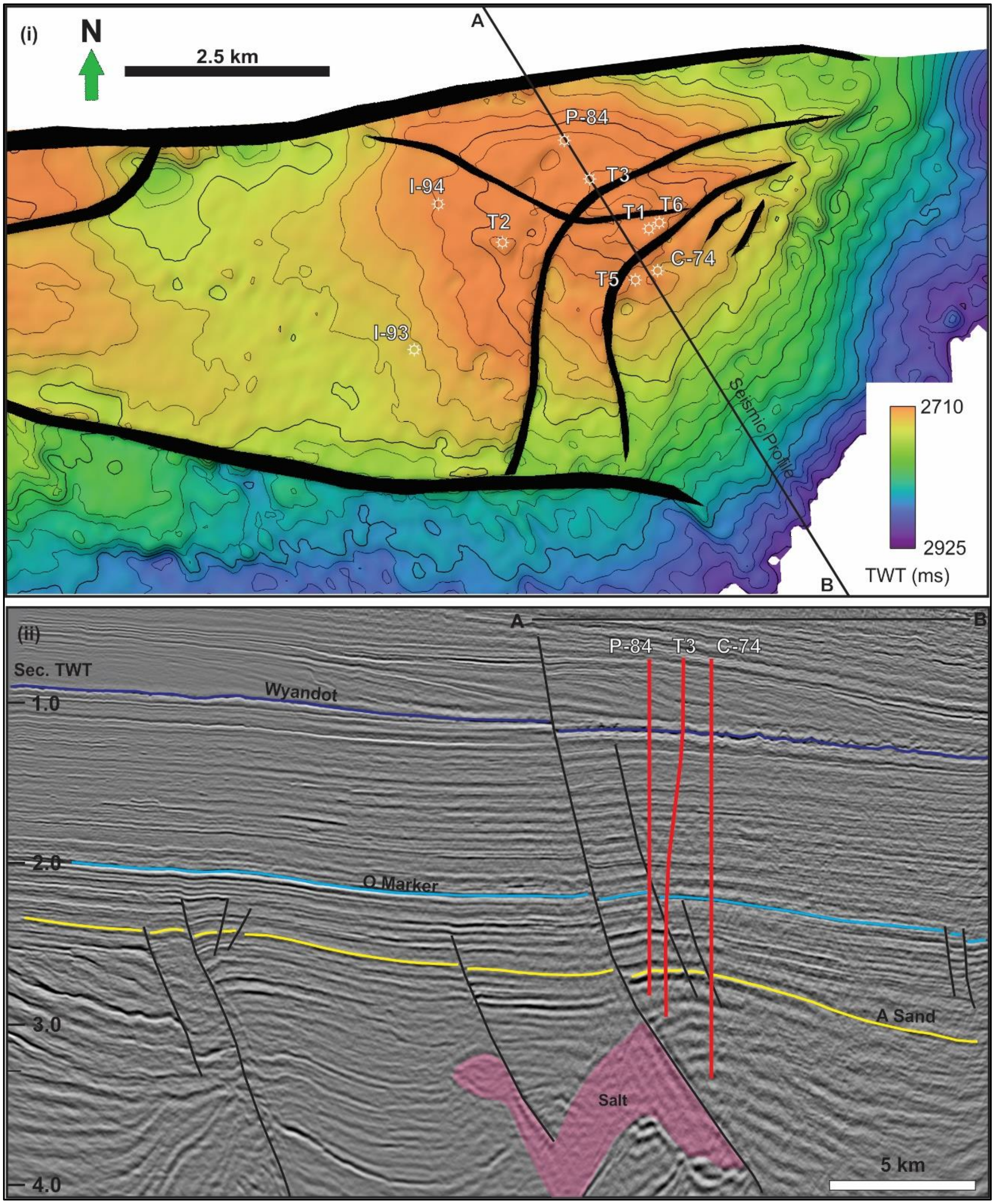

Figure 13: (i) Time-structure map of the Thebaud A Sand displaying the exploration, delineation and production wells. Location of seismic section A-B is shown and well symbols are posted at their downhole intersection with the surface (ii) Dip seismic section A-B intersects the Thebaud P-84 and the Thebaud 3 wells, the Thebaud C-74 well is projected onto this line from a short distance to east (red lines denote borehole paths). The A Sand is highlighted in yellow on the seismic section, and coinciding seismic coverage of above structure map is noted by the length of the A-B line.

North Triumph

The North Triumph structure is a faulted, rollover anticline with an east-west trending structural high. The structure is within a series of salt-detachment faults with varying degrees of offset. Two main faults bound the broad structure to the north and south while a series of smaller offset listric faults are noted at the structure's crest. All faults are interpreted to be linked at depth to a detachment in the Triassic-Jurassic aged Argo salt, however the salt is not well imaged within this seismic survey.

Two development (production) wells were drilled in the North Triumph field as part of the SOEP. These wells are as follows: North Triumph 1 (NT 1) and North Triumph 2 (NT 2). The exploration delineation and development wells drilled in the North Triumph field are displayed on the A Sand time-structure map below.

At the A Sand horizon, North Triumph B-52 penetrates the western edge of the crestal high. North Triumph G-43, NT 1 and NT 2 are located to the east in the central portion of the field near the highest points of the structure.

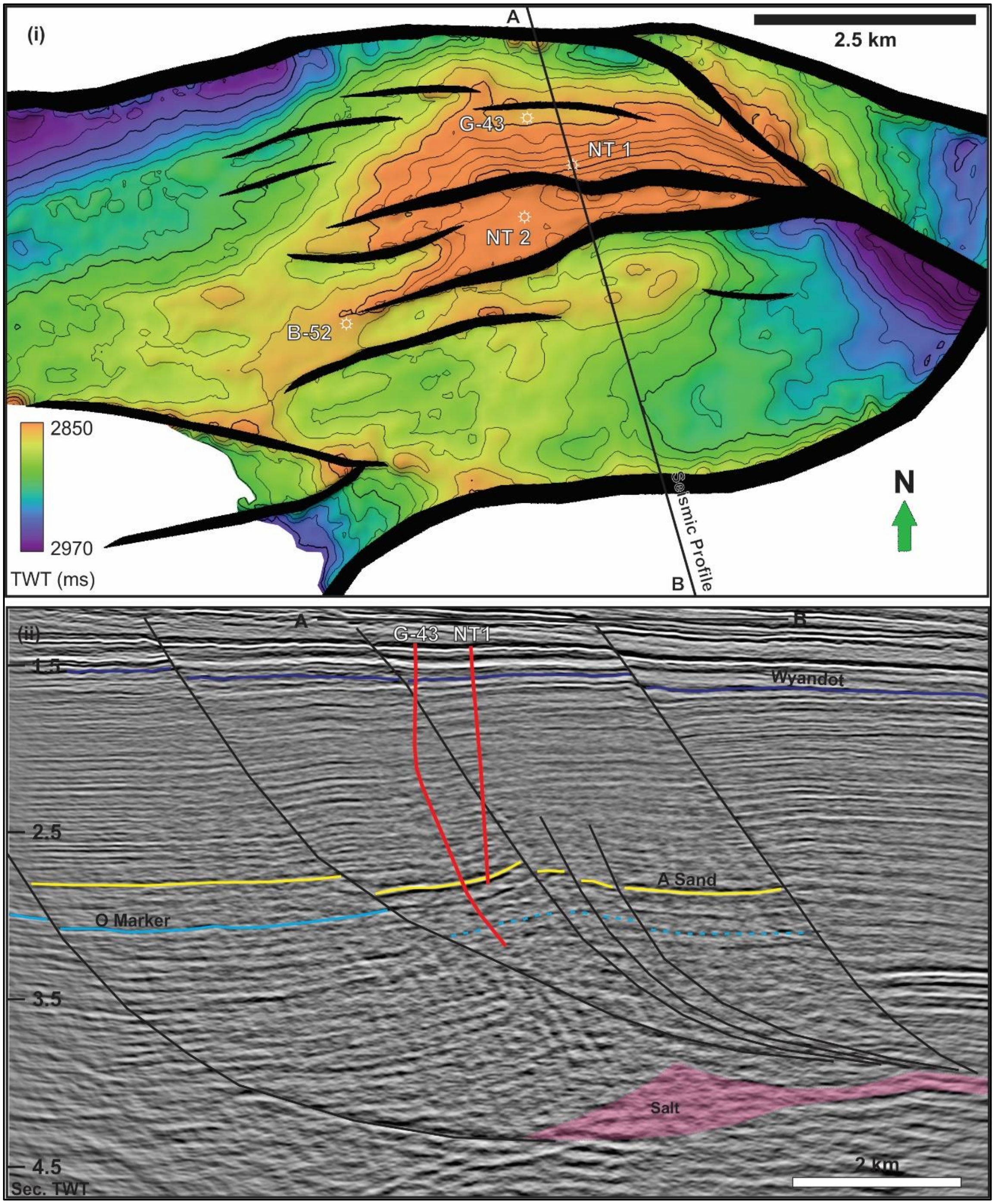

Figure 14: (i) Time-structure map of the North Triumph A Sand displaying the exploration, delineation and production wells. Location of seismic section A-B is shown and well symbols are posted at their downhole intersection with the surface (ii) Dip seismic section A-B intersects the North Triumph 1 well, and North Triumph G-43 is projected on to the line from the west (red lines denote borehole paths). The A Sand is highlighted in yellow on the seismic section, and coinciding seismic coverage of above structure map is noted by the length of the A-B line.

Alma

The Alma structure is a rollover anticline related to basinward displacement along a southwest-northeast trending regional fault in the western Sable Subbasin. While not clearly imaged on the Alma seismic survey due to poor imaging at depth, the bounding regional fault is assumed to be detaching in a deeper Triassic-Jurassic salt interval. Most mapped faults near the Alma field are offsetting seismic reflections with progradational characteristics, these progradational features suggest that the Alma structure is very near the Missisauga delta-front.

Four development (production) wells were drilled in the Alma field as part of the SOEP. These wells are as follows: Alma 1 (A1), Alma 2 (A2), Alma 3 (A3), Alma 4A (A4A - sidetrack). The exploration delineation and development wells drilled in the Alma field are displayed on the A Sand time-structure map below.

A time-structure map of the Alma A Sand highlights the structure's two distinct crests. Alma 1 and Alma K-85 intersect the western high which is bound and sealed by the regional fault to the northwest and a second smaller scale fault to the south. The second high, connected via a structurally lower saddle, is northeast of the A1 and Alma K-85 wells. Alma F-67, A2, A3 and A4A are located near the eastern structural high which is sealed to the northwest by a regional fault and has dip closure to the east and southeast.

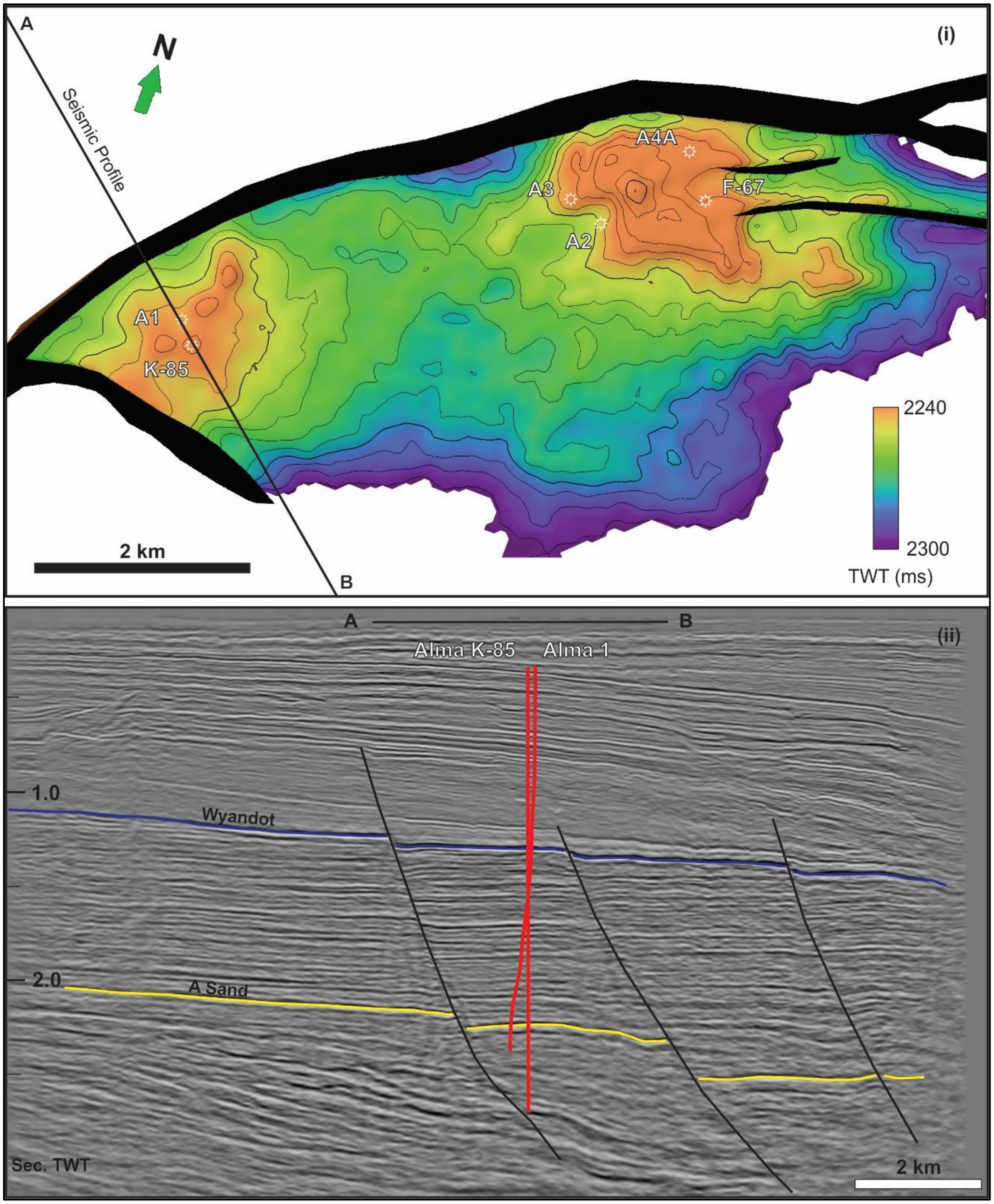

Figure 15: (i) Time-structure map of the Alma A Sand displaying the exploration, delineation and production wells. Location of seismic section A-B is shown and well symbols are posted at their downhole intersection with the surface (ii) Dip seismic section A-B intersects the Alma 1 and Alma K-85 wells (red lines denote borehole paths). The A Sand is highlighted in yellow on the seismic section, and coinciding seismic coverage of above structure map is noted by the length of the A-B line.

South Venture

Three development (production) wells were drilled in the South Venture field as part of the SOEP. These wells are as follows: South Venture 1 (SV 1), South Venture 2 (SV 2) and South Venture 3 (SV 3). The exploration delineation and development wells drilled in the South Venture field are displayed on the Sand C5.0 time-structure map below.

The South Venture structure is a southwest-northeast trending, oval shaped rollover anticline that is bounded to the northwest and southeast by listric faults detaching in allochthonous salt at the easternmost edge of the Sable Shelf Canopy. At the C5.0 seismic horizon, the anticline is broad with simple, four-way closure at the crest and additional three-way closure against the north bounding fault. The SV 2 and SV 3 wells intersect the structure near the crest while SV 1 and South Venture O-59 are lower on structure and rely on fault seal to the north and dip closure to the west, east and south.

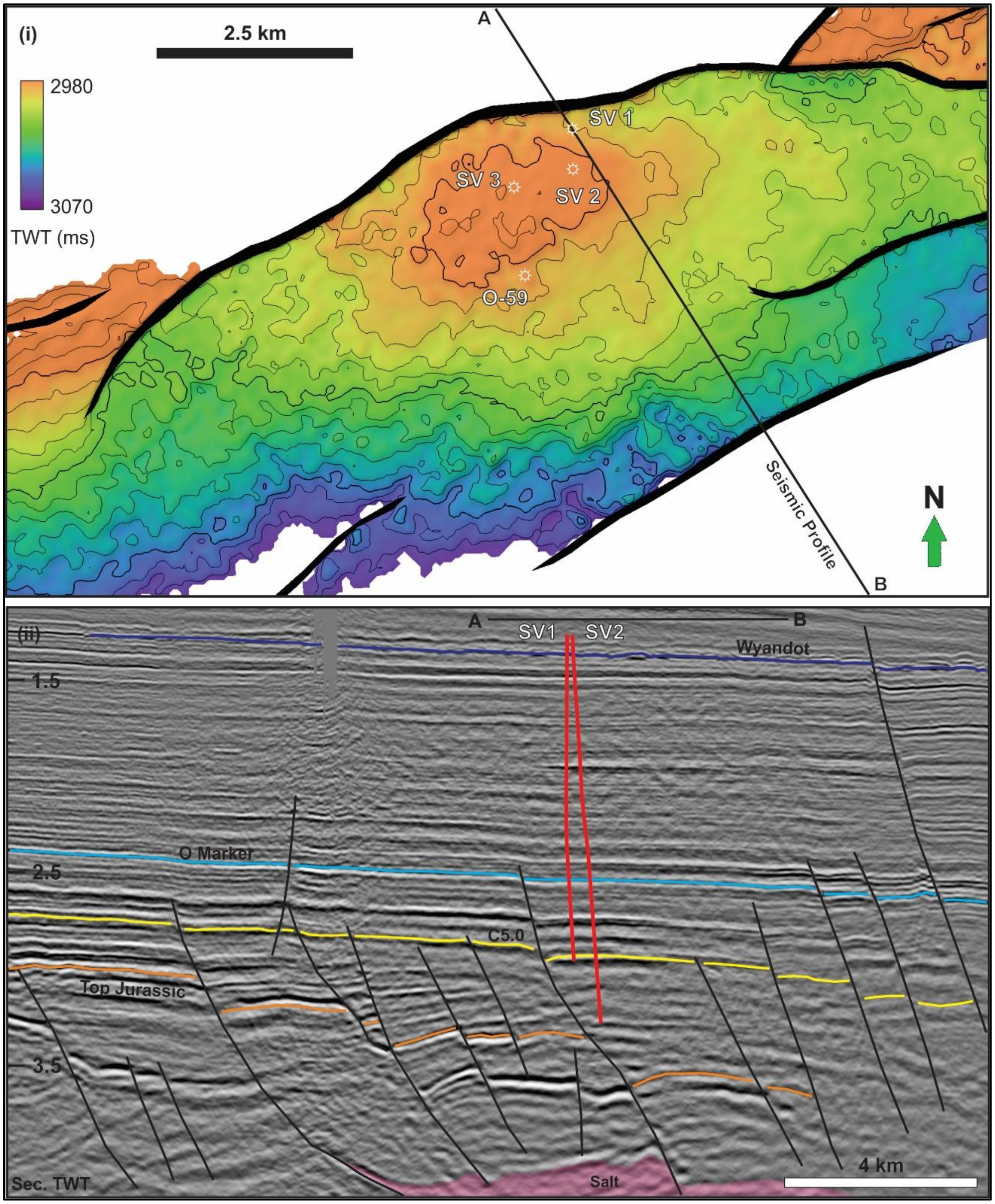

Figure 16: (i) Time-structure map of South Venture Sand C5.0 displaying the exploration, delineation and production wells. Location of seismic section A-B is shown and well symbols are posted at their downhole intersection with the surface (ii) Dip seismic section A-B intersects the South Venture 1 well, and South Venture 2 is projected on to the line from the west (red lines denote borehole paths). Sand C5.0 is highlighted in yellow on the seismic section, and coinciding seismic coverage of above structure map is noted by the length of the A-B line.

CNSOPB Petrophysical Analysis

Overview

The CNSOPB completed a petrophysical analysis of all 21 production wells in the five SOEP producing fields. This section provides an overview of the CNSOPB's petrophysical workflow and summarizes the results of the analysis.

Workflow

The workflow for the CNSOPB's petrophysical analysis was consistent for each of the SOEP producing fields. Open hole curves were assessed for data quality and hole coverage and were depth corrected and edited as required to prepare the data for analysis.

Shale volume (Vsh) was calculated from the gamma ray (GR) curve. Total porosity (PhiT) was calculated from the sonic and density logs and by the neutron-density crossplot method. Shale corrected effective porosity (PhiE) was calculated from the PhiT curves, integrating the Vsh curve. The quality and coverage of each porosity method was reviewed and the final PhiE curve is a merged version of the best data from all porosity calculations considering factors such as well bore conditions, presence of gas etc. Formation water resistivities used to calculate water saturation (Sw) were estimated using the Rwa method, where reliable water analysis data was not available. Net gas pay was determined by applying the following reservoir cutoffs: Vsh ≤ 0.40, Phie ≥ 0.10 and Sw ≤ 0.70.

The results of the CNSOPB's petrophysical analysis are summarized in the tables below.

Venture

Table 7: Venture 1 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand_1	4143.5	4363.1	219.6	41.6	0.11	0.14	0.61
B43_Stray	4363.1	4519.0	155.9	65.2	0.10	0.08	0.48
B13_Stray	4519.0	4588.5	69.5	23.8	0.12	0.07	0.56
Sand_2_Cmt	4588.5	4609.7	21.2	15.3	0.08	0.08	0.42
Sand_2_Porous	4609.7	4660.0	50.3	23.8	0.15	0.16	0.46
Sand_A	4660.0	4723.4	63.4	9.0	0.19	0.10	0.58
Sand_B	4723.4	4769.0	45.6	6.9	0.30	0.11	0.59
Sand_C	4769.0	4849.7	80.7	0.8	0.05	0.16	0.74
3_Limestone	4849.7	4881.0	31.3	16.5	0.08	0.05	0.46
Sand_3	4881.0	5002.7	121.7	25.5	0.23	0.08	0.57
Sand_4	5002.7	5086.6	83.9	21.9	0.25	0.09	0.59
Sand_5	5086.6	5135.2	48.6	22.1	0.22	0.14	0.53
6_Limestone	5135.2	5162.8	27.6	2.3	0.32	0.11	0.54
Sand_6	5162.8	5227.2	64.4	38.1	0.08	0.20	0.37
Sand_7	5227.2	5283.6	56.4	36.7	0.15	0.18	0.44
Sand_8	5283.6	5300.0	16.4	0.0			

Table 8: Venture 2 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand_1	4554.3	4747.0	192.7	8.4	0.44	0.20	0.24
B43_Stray	4747.0	4867.7	120.7	53.6	0.11	0.18	0.23
B13_Stray	4867.7	4924.7	57.0	15.5	0.07	0.09	0.49
Sand_2_Cmt	4924.7	4944.9	20.2	14.3	0.08	0.09	0.38
Sand_2_Porous	4944.9	4986.2	41.3	20.1	0.23	0.15	0.54
Sand_A	4986.2	5033.9	47.7	12.5	0.15	0.16	0.61
Sand_B	5033.9	5076.9	43.0	6.6	0.34	0.17	0.62
Sand_C	5076.9	5140.9	64.0	13.3	0.25	0.20	0.68
3_Limestone	5140.9	5166.9	26.0	0.2	0.32	0.09	0.81
Sand_3	5166.9	5246.0	79.1	11.9	0.22	0.17	0.68
Sand_4	5246.0	5331.4	85.4	21.9	0.21	0.18	0.53
Sand_5	5331.4	5378.2	46.8	14.8	0.17	0.20	0.53
6_Limestone	5378.2	5404.5	26.3	7.8	0.29	0.17	0.49
Sand_6	5404.5	5461.7	57.2	34.1	0.11	0.23	0.32
Sand_7	5461.7	5516.9	55.2	29.3	0.19	0.22	0.66
Sand_8	5516.9	5558.0	41.1	13.1	0.31	0.15	0.67

Table 9: Venture 3 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand_1	4263.2	4452.4	189.2	70.6	0.05	0.15	0.59
B43_Stray	4452.4	4575.3	122.9	43.0	0.06	0.09	0.39
B13_Stray	4575.3	4629.0	53.7	15.1	0.09	0.08	0.52
Sand_2_Cmt	4629.0	4647.8	18.8	15.0	0.06	0.09	0.33
Sand_2_Porous	4647.8	4689.2	41.4	21.0	0.12	0.13	0.50
Sand_A	4689.2	4738.4	49.2	6.6	0.13	0.11	0.60
Sand_B	4738.4	4778.8	40.4	6.9	0.26	0.15	0.67
Sand_C	4778.8	4841.7	62.9	0.6	0.30	0.11	0.55
3_Limestone	4841.7	4868.9	27.2	11.0	0.08	0.20	0.14
Sand_3	4868.9	4974.0	105.1	18.9	0.15	0.19	0.59
Sand_4	4974.0	5049.7	75.7	20.5	0.18	0.15	0.56
Sand_5	5049.7	5095.7	46.0	15.0	0.12	0.20	0.52
6_Limestone	5095.7	5113.0	17.3	0.0			

Table 10: Venture 4 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand_1	4893.0	5102.5	209.5	64.0	0.07	0.13	0.64
B43_Stray	5102.5	5298.5	196.0	60.2	0.08	0.09	0.39
B13_Stray	5298.5	5339.0	40.5	4.0	0.08	0.09	0.54
Sand_2_Cmt	5339.0	5366.9	27.9	21.6	0.09	0.08	0.33
Sand_2_Porous	5366.9	5421.0	54.1	27.0	0.28	0.16	0.50
Sand_A	5421.0	5481.0	60.0	19.2	0.20	0.14	0.66

Table 11: in Venture 5 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand_1	4663.0	4850.9	187.9	46.2	0.08	0.12	0.67
B43_Stray	4850.9	4989.4	138.5	71.8	0.04	0.09	0.46
B13_Stray	4989.4	5044.1	54.7	13.7	0.07	0.08	0.60
Sand_2_Cmt	5044.1	5111.4	67.3	32.5	0.03	0.09	0.47
Sand_A	5111.4	5171.9	60.5	13.4	0.12	0.11	0.67
Sand_B	5171.9	5214.8	42.9	8.1	0.19	0.13	0.70
Sand_C	5214.8	5284.6	69.8	11.4	0.13	0.19	0.71
3_Limestone	5284.6	5309.1	24.5	0.0			
Sand_3	5309.1	5420.0	110.9	16.9	0.12	0.17	0.69
Sand_4	5420.0	5523.9	103.9	14.5	0.14	0.16	0.69
Sand_5	5523.9	5579.1	55.2	14.3	0.05	0.23	0.53
6_Limestone	5579.1	5602.8	23.7	0.3	0.10	0.17	0.83
Sand_6	5602.8	5670.1	67.3	24.4	0.09	0.22	0.49
Sand_7	5670.1	5729.4	59.3	30.0	0.11	0.16	0.55
Sand_8	5729.4	5797.7	68.3	9.3	0.17	0.17	0.69
9_Limestone	5797.7	5943.4	145.7	4.9	0.29	0.09	0.77
Sand_11	5943.4	6042.0	98.6	21.3	0.28	0.17	0.51

Table 12: Venture 6 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand_1	4976.3	5198.8	222.5	0.0			
B43_Stray	5198.8	5362.3	163.5	0.0			
B13_Stray	5362.3	5424.7	62.4	0.0			
Sand_2_Cmt	5424.7	5443.2	18.5	0.0			
Sand_2_Porous	5443.2	5503.5	60.3	0.0			
Sand_A	5503.5	5574.6	71.1	0.0			
Sand_B	5574.6	5624.7	50.1	0.0			
Sand_C	5624.7	5696.1	71.4	18.6	0.12	0.24	0.61
3_Limestone	5696.1	5731.9	35.8	2.8	0.03	0.11	0.71
Sand_3	5731.9	5860.3	128.4	18.1	0.07	0.23	0.65
Sand_4	5860.3	5992.0	131.7	0.0			
Sand_5	5992.0	6037.0	45.0	0.0			

Table 13: Venture 7 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand_1	5900.0	6110.0	210.0	22.1	0.14	0.11	0.66
B43_Stray	6110.0	6280.0	170.0	40.8	0.05	0.22	0.12
B13_Stray	6280.0	6355.0	75.0	7.8	0.02	0.08	0.51
Sand_2	6355.0	6434.0	79.0	43.9	0.21	0.14	0.38
Sand_A	6434.0	6484.0	50.0	0.6	0.37	0.14	0.65

Thebaud

Table 14: Thebaud 1 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand A	3924.2	3959.8	35.6	20.1	0.18	0.19	0.38
Sand B	3968.0	3999.6	31.6	2.6	0.02	0.15	0.55
Sand D3	4086.5	4132.0	45.5	0.0			
Sand F1	4400.7	4453.5	52.8	1.4	0.18	0.12	0.39
Sand F3	4540.4	4591.6	51.2	25.0	0.26	0.14	0.20
Sand G2	4635.1	4645.1	10.0	0.0			
Sand G3	4661.0	4685.3	24.3	2.7	0.10	0.12	0.45

Table 15: Thebaud 2 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand A	4145.7	4178.4	32.7	6.4	0.18	0.18	0.46
Sand B	4185.2	4233.4	48.2	6.4	0.05	0.15	0.47

Table 16: Thebaud 3 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand A	3897.5	3933.0	35.5	16.2	0.09	0.19	0.30
Sand B	3938.6	3981.3	42.7	16.8	0.01	0.19	0.33
Sand D3	4049.5	4089.0	39.5	2.4	0.02	0.19	0.52
Sand F1	4399.1	4436.7	37.6	0.0			

Table 17: Thebaud 5 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand A	4063.8	4098.2	34.4	5.3	0.16	0.19	0.54
Sand B	4105.5	4125.4	19.9	6.4	0.02	0.18	0.55
Sand D3	4175.5	4211.8	36.3	0.3	0.23	0.14	0.62
Sand F1	4485.0	4530.5	45.5	6.7	0.09	0.16	0.38
Sand F3	4618.9	4631.0	12.1	2.6	0.21	0.12	0.41
Sand G2	4670.5	4697.8	27.3	0.0			
Sand G3	4697.9	4716.9	19.0	13.4	0.00	0.18	0.26
Sand H1	4862.0	4878.0	16.0	7.3	0.07	0.15	0.28
Sand H2	4923.5	4973.8	50.3	34.7	0.03	0.18	0.25

Table 18: Thebaud 6 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand A	3929.0	3963.1	34.1	10.4	0.21	0.17	0.31
Sand B	3969.8	3999.9	30.1	11.4	0.10	0.17	0.51

North Triumph

Table 19: North Triumph 1 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
A_Sand	3718.0	3792.0	74.0	45.9	0.10	0.17	0.28

Table 20: North Triumph 2 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
A_Sand	3848.5	3933.1	84.6	28.7	0.17	0.16	0.28

Alma

Table 21: Alma 1 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
LN_Sand	4455.0	4457.0	2.0	0.0			
A12_Sand	4466.0	4514.7	48.7	7.9	0.13	0.21	0.06
A3_Sand	4521.8	4532.4	10.6	0.0			
B4_Sand	4577.0	4584.0	7.0	0.0			
B5_Sand	4594.0	4600.2	6.2	0.0			
B6_Sand	4620.0	4649.4	29.4	1.1	0.29	0.13	0.21
DE_Sand	4711.4	4726.0	14.6	7.6	0.24	0.14	0.18

Table 22: Alma 2 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
LN_Sand	3422.5	3425.6	3.1	0.5	0.31	0.14	0.20
A12_Sand	3428.9	3478.0	49.1	13.7	0.22	0.15	0.23
A3_Sand	3482.0	3504.0	22.0	5.0	0.27	0.15	0.23

Table 23: Alma 3 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
LN_Sand	3141.0	3143.0	2.0	0.2	0.26	0.14	0.40
A12_Sand	3145.3	3189.4	44.1	19.4	0.20	0.17	0.22
A3_Sand	3191.3	3198.1	6.8	0.2	0.24	0.12	0.38
B4_Sand	3237.2	3240.7	3.5	0.0			
B5_Sand	3248.0	3261.0	13.0	2.4	0.17	0.16	0.25
B6_Sand	3263.3	3277.1	13.8	2.7	0.29	0.12	0.45
DE_Sand	3327.7	3363.0	35.3	4.6	0.13	0.14	0.56

Table 24: Alma 4A Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
LN_Sand	4078.0	4085.2	7.2	1.4	0.08	0.14	0.25
A12_Sand	4087.0	4134.9	47.9	15.1	0.12	0.20	0.15
A3_Sand	4137.6	4143.9	6.3	2.0	0.17	0.15	0.33
B4_Sand	4185.2	4187.3	2.1	0.0			
B5_Sand	4194.6	4202.9	8.3	0.0			
B6_Sand	4205.5	4214.5	9.0	0.0			

South Venture

Table 25: South Venture 1 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand C6.1	3863.9	3885.0	21.1	0.9	0.33	0.12	0.25
Sand C6.0	3885.0	4005.6	120.5	31.2	0.19	0.19	0.35
Sand C5.8	4005.6	4025.2	19.6	6.2	0.10	0.13	0.46
Sand C5.8ls	4025.2	4071.9	46.7	12.2	0.11	0.14	0.36
Sand C5.6	4071.9	4102.2	30.3	5.5	0.26	0.13	0.28
Sand C5.6ls	4102.3	4143.5	41.2	20.4	0.08	0.16	0.28
Sand C5.5	4143.5	4165.4	21.9	0.2	0.00	0.12	0.52
Sand C5.4	4165.4	4215.8	50.4	1.5	0.15	0.11	0.49
Sand C5.3	4215.8	4307.5	91.7	14.0	0.09	0.15	0.35
Sand C5.1	4307.5	4359.8	52.3	4.3	0.07	0.12	0.26
Sand C5.0	4359.8	4451.0	91.2	37.9	0.08	0.15	0.26

Table 26: South Venture 2 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand C6.1	3866.4	3888.4	22.1	2.7	0.33	0.12	0.30
Sand C6.0	3888.5	3999.9	111.4	18.1	0.22	0.17	0.43
Sand C5.8	3999.9	4021.2	21.3	9.9	0.05	0.14	0.28
Sand C5.8ls	4021.2	4067.1	46.0	12.7	0.11	0.14	0.37
Sand C5.6	4067.2	4095.6	28.4	1.4	0.24	0.13	0.39
Sand C5.6ls	4095.6	4139.3	43.7	24.1	0.09	0.13	0.30
Sand C5.5	4139.3	4163.9	24.6	5.2	0.06	0.12	0.30
Sand C5.4	4163.9	4213.9	50.0	3.4	0.09	0.12	0.31
Sand C5.3	4213.9	4310.8	96.9	20.7	0.10	0.17	0.49
Sand C5.1	4310.8	4365.1	54.2	4.7	0.19	0.12	0.45
Sand C5.0	4365.1	4873.4	508.3	42.4	0.08	0.21	0.23
Sand D	4873.4	4890.8	17.4	0.2	0.28	0.10	0.34
Sand C1	4890.8	5038.3	147.5	0.0			
Sand E1	5038.3	5217.9	179.6	0.9	0.04	0.11	0.49
Sand J210	5217.9	5332.0	114.1	6.6	0.05	0.11	0.59

Table 27: South Venture 3 Petrophysical Results

Sands	Top	Bottom	Gross Thk (m)	Net Pay (m)	Avg Vsh (v/v)	Avg PhiE (v/v)	Avg Sw (v/v)
Sand C6.1	4028.7	4049.2	20.5	0.0			
Sand C6.0	4049.2	4153.4	104.2	12.0	0.21	0.15	0.34
Sand C5.8	4153.4	4171.4	18.0	2.3	0.14	0.11	0.31
Sand C5.8ls	4171.4	4217.2	45.8	13.1	0.14	0.12	0.38
Sand C5.6	4217.2	4235.8	18.6	0.2	0.17	0.10	0.29
Sand C5.6ls	4235.8	4289.8	54.0	28.5	0.10	0.17	0.21
Sand C5.5	4289.8	4313.4	23.6	2.1	0.05	0.11	0.26
Sand C5.4	4313.4	4362.1	48.7	1.2	0.01	0.12	0.57
Sand C5.3	4362.1	4451.4	89.3	22.3	0.16	0.18	0.49
Sand C5.1	4451.4	4495.2	43.8	2.0	0.21	0.12	0.40
Sand C5.0	4495.2	4683.0	187.8	9.9	0.15	0.16	0.29

CNSOPB Regulatory Oversight

As the life cycle regulator for petroleum activities in the Canada-Nova Scotia offshore area, the CNSOPB ensured the operator maintained an ongoing commitment to resource management and conservation (waste prevention) for the entire duration of the project from initial development drilling to well plugging and abandonment. The operator was required to demonstrate to the CNSOPB on a regular basis that they had a comprehensive understanding of the petroleum resources under development and that their production activities maximized economic hydrocarbon recovery of the SOEP resources and thus did not result in waste.

The CNSOPB's resource management oversight included independent geoscience and reservoir engineering studies, monitoring and surveillance of development and production activities and audits of the operator's resource management strategies and practices. In addition, advanced resource management tools and techniques were developed to monitor regulatory compliance during the life of the project. The following are brief descriptions of some of the tools and methods used by the CNSOPB to ensure regulatory compliance and to confirm that waste of the resource did not occur.

Daily Monitoring and Surveillance

The *Nova Scotia Offshore Petroleum Drilling and Production Regulations* (Drilling and Production Regulations), requires operators to submit a daily production record, which includes but is not limited to gas and water production rates, water/gas ratio (WGR), tubing and subsurface pressures, flare volumes and fuel gas volumes.

The CNSOPB used various monitoring, surveillance and visualization tools and dashboards, on a daily basis, to ensure any production anomalies were detected quickly. If anomalies were detected these would be reviewed with the operator to ensure alignment on the resource management approach that would be applied. The following are the key production parameters that were monitored daily for each SOEP production well:

- Daily gas production rate and production hours
- Daily condensate production rate and condensate/gas ratio
- Daily water production rate and water/gas ratio
- Daily wellhead and bottom-hole flowing pressure
- Daily wellhead and bottom-hole shut-in pressures and comparison charts
- Flared gas (percent of daily production)

- Choke settings

The CNSOPB also monitored daily gas prices. These prices were used in various economic analyses and sensitivities to ensure economic hydrocarbon recovery was maximized (waste prevention).

Monthly Monitoring and Surveillance

The Drilling and Production Regulations also require *"the operator to submit a report summarizing the production data collected during the preceding month"*. To satisfy this requirement, the operator submitted monthly production reports to the CNSOPB while production was ongoing. The monthly production reports included the following data:

- Total field gas production
- Total field condensate production
- Total condensate and gas used as fuel
- Total gas flared
- Total water produced from the field

The CNSOPB used the above monthly production data to further analyze and monitor the performance of the fields. The monthly data was used to perform decline analyses once the wells started declining in order to predict remaining gas production. As an example, charts of monthly gas and water production data from the Thebaud 1 (T1) well are included below.

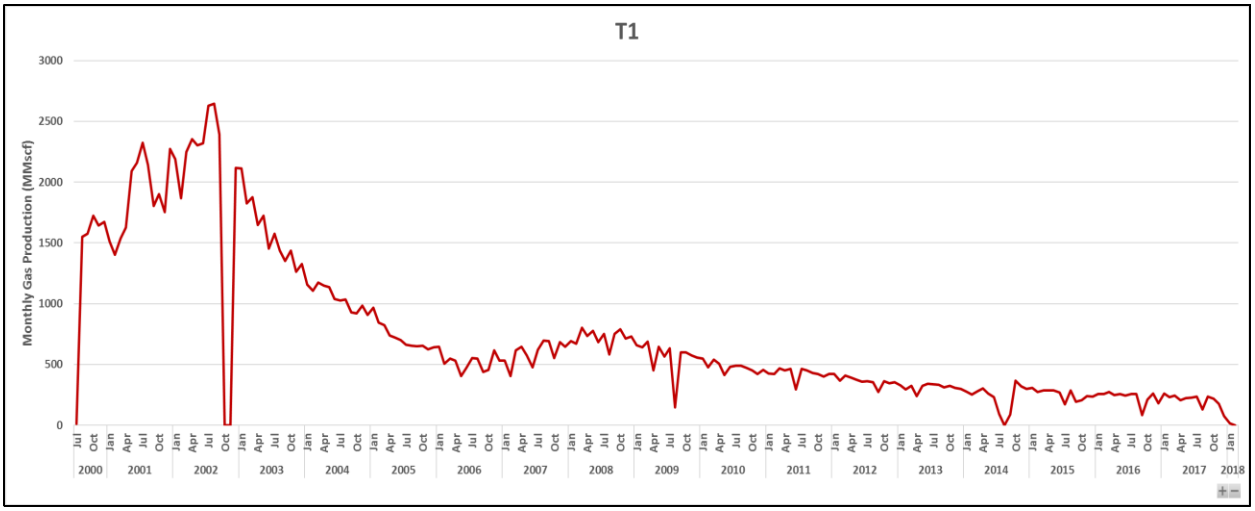

Figure 17: Thebaud 1 Monthly Gas Production. After an initial peak, the chart displays the gradual decrease of production with time over the life of the well.

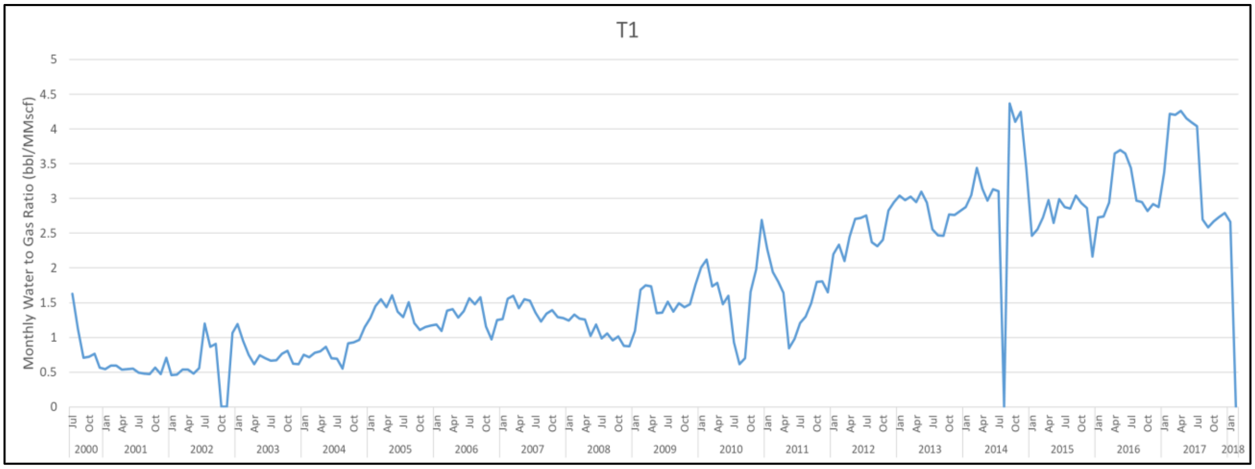

Figure 18: Thebaud 1 Monthly Water/Gas Ratio (WGR). As can be seen from the chart, the WGR increased over the life of the well.

Annual Production Reports

The Drilling and Production Regulations state that *"the operator shall ensure that, not later than March 31 of each year, an annual production report for a pool, field or zone is submitted to the Board providing information that demonstrates how the operator manages and intends to manage the resource without causing waste".*

These Annual Production Reports (APR) review the performance of all producing wells and sands (pools), in each field, during the previous year. This report is a key resource management document that is used by the CNSOPB to evaluate whether the field is being produced and managed in a manner that will not result in waste of the resource.

Production Forecasting

Forecasting future gas and condensate production from the SOEP wells was a key aspect of resource management for the project. These production forecasts were used for a number of purposes including but not limited to the following: estimating remaining reserves, optimizing production and timing the cessation of production. Future production was predicted using reservoir simulation models in the early years of production. Later in the life of each well after production began declining, decline curve analysis was used to estimate the remaining producible reserves in each well.

Economic Analysis and End of Field Life Analysis

To ensure "waste" as defined in the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act* (federal) does not occur, the CNSOPB is required to consider *"sound engineering and economic principles"* when making decisions related to production activities such as well workovers, drilling of additional wells and the cessation of production. In order to verify that the timing of production cessation for SOEP would not result in waste, the CNSOPB conducted a detailed economic analysis which included all costs, commodity prices and production sensitivities. The CNSOPB's economic analysis was conducted using both deterministic and probabilistic assessment methods. This economic analysis combined with an assessment of remaining reserves allowed the CNSOPB to ensure that the timing of production cessation for SOEP would not result in waste.

Resource Management Plans

The Drilling and Production Regulations state that *"the development plan relating to a proposed development of a pool or field shall contain a resource management plan"*. The Resource Management Plan (RMP) is the main resource management document that describes how the operator intends to maximize economic hydrocarbon recovery (prevent waste) over the life of the project. During the project as new data is acquired (e.g. production data, well test data, updated simulation models etc.) the operator is required to ensure that this new data is analyzed and incorporated into the RMP to enhance the understanding of each producing reservoir to ensure waste does not occur. The following are some of the key elements that are included in an RMP:

- Geological and geophysical description of each field(s)
- Petrophysical interpretations and analysis of each sand (pool) in the field(s)
- Reservoir engineering analyses and data
- In-place and recoverable reserve estimates
- Project depletion plan including the number of wells and contingent wells
- Design of the production wells and a review of potential workovers
- Description of the production and export systems
- Expected overall operating efficiency
- Development and operating cost data

In addition to the initial RMP, the operator is also required to provide annual RMP updates. These annual updates should include any changes to the in-place and recoverable hydrocarbon volumes, updated reservoir characterization, changes in production behaviour and any updates to the depletion plan. Economic information such as operating and capital costs are also included in these annual RMP updates.

Resource Management and Well Review Meetings

Regular formal and informal meetings were scheduled with the operator's reservoir management staff to discuss updates to the reservoir description, review changes in well and field performance, discuss well workovers, resource management strategies and depletion planning.

Analysis of Potential Workover Opportunities

Later in the life of the project the CNSOPB conducted an assessment to ensure that any remaining potential well workover opportunities within the SOEP fields was evaluated to ensure that maximum economic recovery of hydrocarbons was achieved prior to the cessation of production.

Resource Management Audits and Compliance Verification

The CNSOPB's resource Conservation Officers also conducted audits of the operator's resource management strategies and practices including their reservoir simulation models. The scope of these audits included the following:

- SOEP Well and Field Surveillance Audit
- SOEP Integrated Production Model Audit
- SOEP Well Production Management Audit.

Actual vs. Expected Production

The following figure displays the actual production from the five SOEP producing fields over the life of the project.

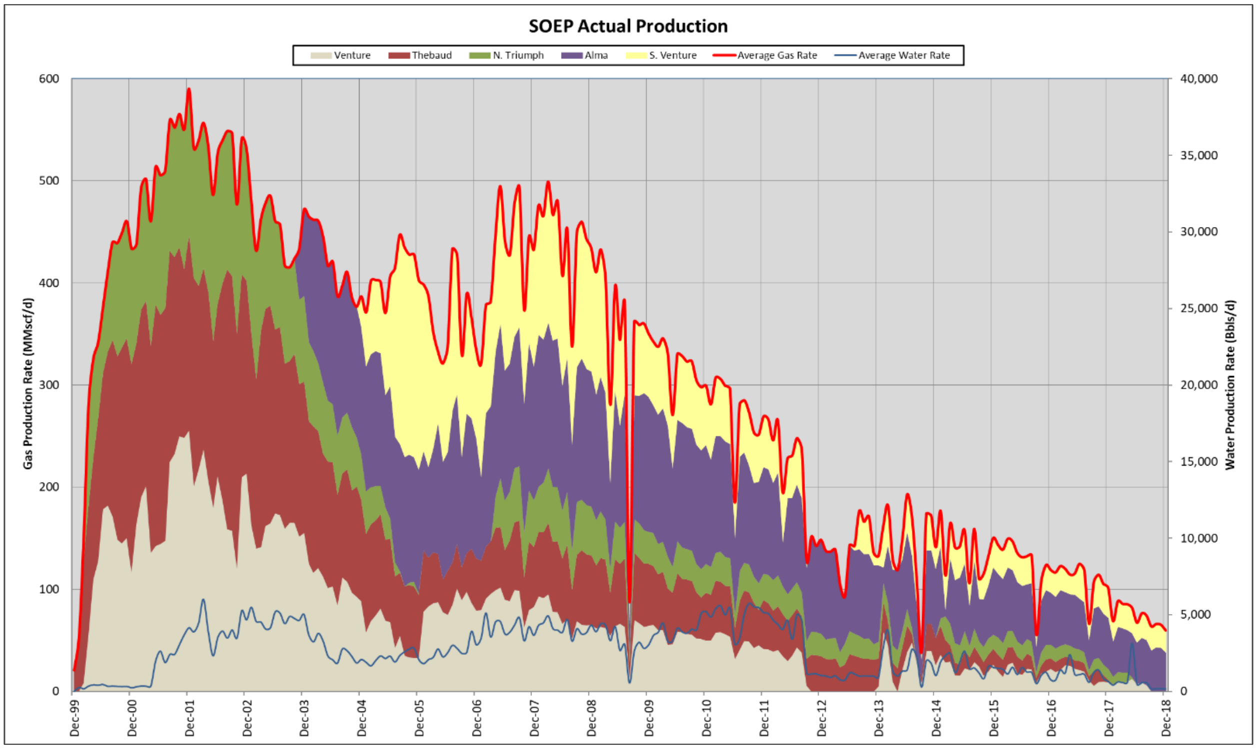

Figure 19: Actual SOEP gas and water production over the life of the project. The increase in production rate, that begins in late 2006, is related to the start-up of compression.

The following table provides a comparison of the actual recovered gas volumes from each field with the expected recoverable volumes included in the SOEP Development Plan Application (DPA).

Table 28: SOEP DPA Expected vs. Actual Gas Recovery

Field	DPA Mean (Expected) Recoverable Gas E9m3 (Bcf)	Actual Recovered Gas E9m3 (Bcf)
Thebaud	16.9 (597)	14.2 (501)
Venture	32.2 (1137)	14.0 (494)
North Triumph	10.2 (360)	8.3 (292)
South Venture	7.8 (276)	8.9 (315)
Alma	9.4 (332)	14.6 (516)
Total	**76.5 (2702)**	**60.0 (2118)**

As can be seen from the table above, overall gas recovery from Thebaud and North Triumph was somewhat lower than predicted in the SOEP DPA while actual production from South Venture was somewhat higher than expected. Actual production from Alma was far in excess of the expected recovery while Venture production was significantly below what was predicted at the time of the SOEP DPA. Overall SOEP actual gas recovery from the five producing fields was lower than predicted in the DPA, primarily due to significantly lower than expected gas recovery from the Venture field.

The following section will summarize the key resource management lessons learned over the life of the project.

Key Resource Management Learnings

The CNSOPB's key resource management learnings from the Sable Offshore Energy Project are summarized below.

1. There were no significant changes to the Gas In Place estimates for the five SOEP producing fields over the life of the project.

2. The upper Missisauga project sands generally had higher gas recoveries than the deeper overpressured reservoirs.

3. The timing of well workovers and completions is a key consideration to ensure recovery is optimized from all producing zones.

4. Venture's actual recovery was significantly lower than expected, in the DPA, as some of the key reservoirs experienced sand and water production issues.

5. The CNSOPB's regulatory oversight included audits of the operator's resource management strategies and practices including the maintenance of production equipment and facilities. These audits were an important aspect of the CNSOPB's regulatory oversight of the project and were designed to ensure waste of the resource was not occurring.

6. Access to the operator's detailed economic data allowed the CNSOPB to ensure waste did not occur when considering resource management decisions such as the timing of well workovers and cessation of production.

7. Sand management was a significant challenge for some of the overpressured reservoirs.

8. Cycling wells after the start of water and/or sand production proved to be an effective way to maximize recovery from these sands.

9. The frequency of rate testing should be adjusted to match well behaviour. Wells with stable production can be tested less often while wells with more variable behaviour should be tested more frequently.

10. Where well behaviour and gas composition is generally consistent the frequency of sampling can be reduced.

11. Simulation modeling was an important tool for depletion planning and reservoir management at the pre-development phase and during early production. Once production from the wells began declining, other tools and techniques such as Integrated Production Modelling and decline analysis were the primary methods used to forecast production from the wells.

References

Sable Offshore Energy Project Development Plan Application - Volume 2 (June 1996).