Analysis of Petroleum Potential in Queen Charlotte Basin

Phase I Report
Broad-Scale Basin Characterization

Project Sponsored by Offshore Oil and Gas Branch
Ministry of Energy and Mines
Government of British Columbia

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Phase I Report: Broad-Scale Basin Characterization

1. Executive Summary

This 2-phase project, commissioned by the B.C. Ministry of Energy and Mines, creates a unified assessment using our Petroleum Systems Modeling of available geophysical, geologic and geochemical information for the Queen Charlotte Basin (QCB). The primary objective is to refine the definition of the most probable sectors of petroleum formation in the region. The report evaluates available data and reviews processes and important parameters, which influence hydrocarbon generation in the area. Due to the restriction of data coverage, this report encompasses ca. 23,000 km^2 of the approximately 65,000 km^2 area of the Queen Charlotte and Hecate Basins.

1.1 Approach

In this Phase I report we present our initial Petroleum Systems Modeling results and the assessment based on them. This represents the culmination of our efforts to

1. Identify the relevant existing information base, review and update
   a) the stratigraphic record based on well and outcrop reports
   b) the geologic-structural record based on seismic survey data and well samples

2. Apply the existing geophysical and tectonic framework using the available reflection seismic data, especially the 1988 MCS surveys by the Geological Survey of Canada (GSC)

3. Reconstruct the QCB burial history using a backstripping method based on the sediment stratigraphy established from the 8 offshore exploration wells and the regional seismic survey data

4. Input data into Petroleum System Model, including previously available information and that generated in this report on:
   a) QCB basin formation (structural-tectonic timing)
   b) sedimentary unit thicknesses and ages
   c) available sedimentologic parameters, e.g., sediment type (shale, sandstone, volcanic, etc.)
   d) source rock information (%TOC, kerogen types, maturity)
   e) heat flow history

5. Create 1D Petroleum Systems Models using IES PetroMod 8.0, with input data from the 8 offshore well, to estimate:

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a) maturation history of source rocks
b) petroleum product formation thresholds and timing
c) spatial extent of oil and gas formation and occurrence

6. Regional (basin-wide) assessment of petroleum generation concept based on 1D Petroleum Systems Model results and 2D interpretations.

1.2 Primary Outcomes

The major outcomes of Phase I of this project are as follows:

1. Sufficient drill well, seismic data and outcrop information are available to make a reasonable, initial assessment of the conditions of the Cenozoic (Paleogene, Neogene) sedimentary package in Queen Charlotte Basin with respect to petroleum formation. This means that a rough mapping of the maturity of Tertiary-age rocks in the basin is possible, for today and over the past 60 Ma.

2. Considerable structural and sedimentological variability is recorded in the QCB. For example considerable differences are noted for the thickness of specific lithologic unit. In addition, important lateral facies changes are known for sediments of similar age. Some of this is recognized in the multi-channel seismic and drill well data.

   This heterogeneity severely limits the identification and definition of specific exploration plays. However, the available data permit a regional overview to be made, especially for the Cenozoic.

3. The information base on Mesozoic sediments is much more limited than for the younger units. The lack of drill well control, coupled with the poor seismic information on the older units, are serious constraints on the interpretation of the Jurassic and Cretaceous sequences. The estimations of petroleum formation for these older units are significantly less reliable.

4. There is some uncertainty in the heat flow history of the QCB, however, a reasonable estimation can be made and constrained by a) recent measurements of heat flow (Lewis, 1991), and b) the measurements of vitrinite reflectance on cuttings from the 8 offshore drill wells (Vellutini and Bustin, 1991a, b). In concert with burial history and timing, the heat flow history for the basin is critical for accurate prediction of maturation and generation. Fortunately, our studies have demonstrated that only the more recent heat flow (last ~10 Ma) is important for the maturation of Cenozoic sediments. This is due to the limited burial of early Tertiary sediments before the latest Oligocene/early Miocene.

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5. Based on our models, we have defined 6 maturity stages for the QCB:
    a) Immature – no generation expected
    b) Marginally Mature – very limited and special generation, i.e., resinites
    c) Mature oil – generation of oil if appropriate source rocks present
    d) Mature oil + gas – generation of oil and gas if appropriate source rocks present
    e) Late mature – predominantly dry gas (methane) or condensate
    f) Overmature – overcooked source rocks, no generative potential remaining today

    The QCB Cenozoic package typically enters the top of the petroleum window today at or just deeper than 2,100 m (0.5 %Ro, Type II). Restricted, if any, production will result in the shallower Marginally Mature zone (1,200 to 2,100 m). The oil window (Mature, oil) today extends to depths of approximately 2,800 m (0.8 %Ro, Type II), while the Mature oil + gas window currently brackets 2,800 to 4,100 m. The bottom of this zone is deeper than most of the wells drilled in the QCB. Most of the offshore QCB wells encountered Cenozoic sediments which have a maturity of less than 0.8 %Ro, i.e., are in the formation stage of early petroleum window or younger. The Sockeye B-10 well is an exception in that at TD (4,773 m) the measured maturity of the sediments is ca. 2 %Ro.

    Based on the measured %Ro profiles for the wells, the Late Mature (gas window) in the QCB today is between 4,100 m and 4,800 m (1.2 – 2.0 %Ro, Type II). At greater depths any source rocks are overmature today, but may have generated hydrocarbons in the past. Only the Sockeye B-10 approaches the base of the gas generation zone.

    Any sedimentary units currently deeper than 4,800 m are likely Overmature. They have little, if any, generative potential remaining, but may have generated hydrocarbons in the past.

Table 1 Summary of expected present day Cenozoic maturity zonation depths

Maturity Zone	VR range (% Ro)	Minimum Depth (m)	Maximum Depth (m)
Immature	< 0.3	0	< 1,200
Marginally Mature	0.3 – 0.5	1,200	2,100
Mature (oil)	0.5 – 0.8	2,100	2,800
Mature (oil + gas)	0.8 – 1.2	2,800	4,100
Late mature (gas)	1.2 – 2.0	4,100	4,800
Overmature	> 2.0	>4,800	

Notes: 1) due to insufficient coverage, these maturity depths are calibrated for the Cenozoic units only. Mesozoic sequences may display different maturation profiles, but this is not known.
2) generally valid only for oil prone Type II kerogens. Humic Type III kerogens show different kinetic behavior.

6. Our modeling demonstrates that the maturation depth profiles of the Cenozoic units are relatively uniform across the basin, i.e., at any particular depth, the maturity will be approximately the same for different locations in the QCB. This reflects the more or less consistent, recent subsidence and heating history.

7. Variations in unit sediment thickness remain important to assess the amount of hydrocarbons generated. The maturation does not account for the volume or quality of the oil and gas – this is made by %Total Organic Carbon and Hydrogen Index.

8. By combining geochemical parameters with the stratigraphic history, we produce initial models for the formation of Cenozoic -sourced oil and gas for the QCB. It is important to note that this assessment is for the Cenozoic only, the Mesozoic will be addressed in Phase II of this project.

9. Based on the interpretation of existing information, extensive generation of oil and gas from Cenozoic units of the QCB is not basin-wide, rather it is more restricted to specific sections of the basin. The Neogene-age areas expected to be most productive in forming oil and gas is in a fairway approximately 75 km wide and 380 km long that extends northwest to southeast roughly parallel to the axis of Hecate Strait (Figure 1). This corresponds to an approximate area of 23,000 km^2. Our initial assessment indicates that region more to the western side of the Strait is rated more favourably than the

eastern side, including the mainland coast. This is consistent with other reports, including evaluations by the GSC (e.g., Hannigan et al. 2001)

It is important to note that this stage of our assessment does not address the migration or trapping histories in the QCB, and thus makes no prediction as to potential reservoir locations, frequency or sizes.

10. Our assessment of the present day region of interest for hydrocarbon generation from Cenozoic strata in the QCB is restricted to sectors with existing seismic and drill well coverage (study area). This represents only ca. 23,000 km^2 (dotted blue outline in Figure 1) of the approximately 65,000 km^2 area of the Queen Charlotte and Hecate Basins (dotted red outline in Figure 1), or ca. 60,000 km^2 area of the offshore region (Dixon Entrance, Hecate Strait and part of Queen Charlotte Sound, orange line in Figure 1).

    Our initial evaluation of the maturation of the Cenozoic strata in the study area suggests that ca. 72 % of these source rocks (ca. 16,700 km^2) presently have the maturity range for the generation of oil and/or gas. Approximately 4 % (ca. 770 km^2) are overmature and 24 % (ca. 5, 500 km^2) are undermature. These estimates are summarized in Table 2.

Table 2. Comparison of maturation zone areas in Cenozoic source rocks of Queen Charlotte Basin.

Present Day Cenozoic Source Rocks of Study Area of Queen Charlotte Basin	Approximate Area Neogene Strata in Study Area (km^2)	% of Neogene Strata in Study Area
Undermature (immature and marginally mature)	5,500	24
Mature (oil, gas and oil/gas)	16,700	72
Overmature	770	4

11. In this phase of the project, no detailed predictions of the Mesozoic are made. Although sediments deeper than 4,800 m today are likely overmature, there are periods of time in the history of the Mesozoic when they generated oil and gas. A complete treatment of the QCB requires careful consideration of source rocks and potential reservoirs from this era.

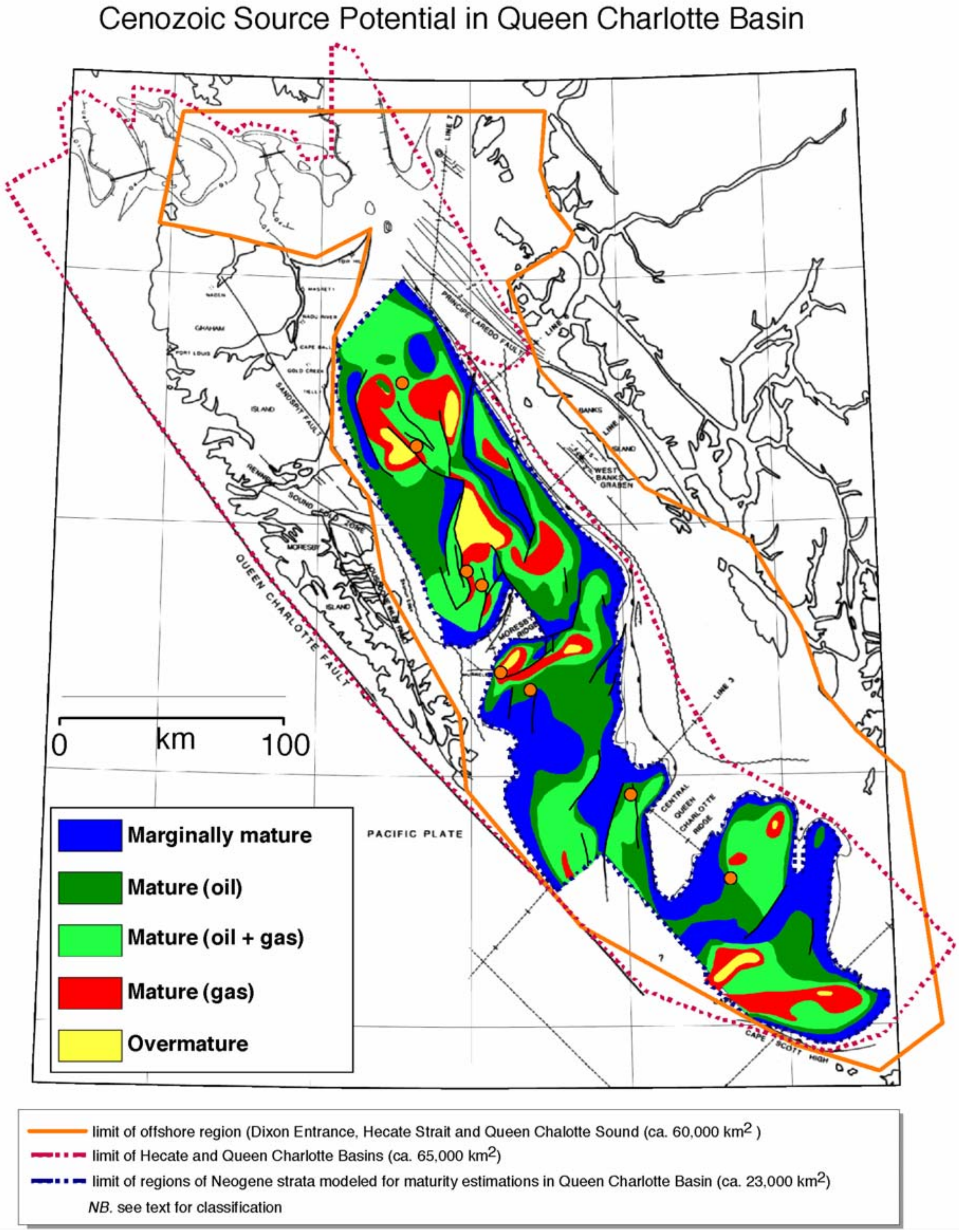

Figure 1. Map of Queen Charlotte Basin region showing the present day maturity zones of the Neogene sediment package and the outlines of the offshore region and the Hecate + Queen Charlotte Basin. The structural information is from Rohr and Dietrich (1992).

1.3 Constraints, Concerns and Challenges

1. Coverage of seismic reflection data for the QCB is essentially limited to 1000 km of multichannel seismic shot on 8 lines by the GSC in 1988. For a basin the size of the QCB and with its higher level of geologic complexity, this degree of coverage is inadequate.

2. Only 8 wells have been drilled offshore in the QCB, spaced over an approximate 300 km distance, roughly parallel to the axis of the basin. Some of these wells were drilled for stratigraphic reasons and not necessarily placed in locations elucidate the most information.

3. Offshore wells mostly terminate in Cenozoic (lower Tertiary) or uppermost Cretaceous units. No information or samples on the anticipated and important Jurassic marine source rocks (oil prone) is available.

4. Mesozoic tectonic and basin history, critical for the estimation of oil, is difficult to assess with existing information and data, including paleo-heat flow.

5. Timing of the Tertiary Rifting event is poorly constrained (early Miocene?). The basalts at this time have not been adequately dated and the fossil coverage is extremely poor at that time. The timing is important to define the start of the Paleogene subsidence and the onset of elevated heat flows. Fortunately, this timing is less of an issue for the assessment of the Tertiary package, than for the Mesozoic oil-prone source rocks.

6. The dating of the Skonun Fm, a critical sedimentary unit, needs updating.

1.4 Recommendations

At the end of Phase I we have identified several components that could definitely or potentially enhance the interpretation and assessment of the petroleum formation in the QCB. Most of these recommendations exceed the scope of this project, but are expressed here as positive steps that could be taken to improve the understanding of the basin. Generally these recommendations fall into three categories, A) Geophysics, B) Stratigraphy, and C) Geochemistry as follows:

A) Geophysics

1. Re-interpret the existing geophysical and tectonic framework using reflection seismic data, especially the 1988 MCS surveys by the Geological Survey of Canada (GSC) and possibly the recent UVic data (R. Chapman), to:

a) Provide the best resolution within the Tertiary and the Cretaceous sediments

b) Transfer the interpretation into a seismic interpretation system

This seismic information enhancement could involve a professional reprocessing of the reflection data, including improved velocity picks.

2. Attempt to re-evaluate the 1988 MCS seismic survey data using a refraction seismic mode to better delineate the basement and possibly Mesozoic intervals.

3. Incorporate additional seismic data shot in the QCB, such as the Chevron Texaco and Shell Canada seismic data. This data could provide critical infilling of information for the basin.

B) Stratigraphy

1. Reliable chronologies and age control is essential to interpret the basin evolution, including groundtruthing the geophysical information. Several attempts have been made to generate a chronostratigraphic framework for the basin using cuttings from the 8 offshore wells, albeit for the Cenozoic and latest Mesozoic only. There are significant inconsistencies between these various interpretations and findings that need to be resolved. This may involve re-analysis of specific horizons using the original cuttings and well logs.

2. A major deficiency in the petroleum assessment for the basin is the lack of reliable information on Mesozoic units. These are particularly important for the generation of oil, especially the Jurassic Kunga and Maude groups. source rocks. Recently, it has come to our attention that outcrops of these units may exist on land on the northern tip of Vancouver Island. It is highly recommended that these possible outcrops be visited, sampled and analysed.

C) Geochemistry

1. Pockmarks and petroleum seepages are well known, or suspected, on land and in the Hecate Strait of the QCB. These overt expressions of hydrocarbons can provide key information on the character of the petroleum deeper in the basin. Many of the seeps based on the Queen Charlotte Islands (QCI) have been examined and characterized, but little work has been performed on the seafloor indicators. These pockmarks have been mapped previously, including the extensive work by V. Barrie, GSC-Victoria. It is recommended that these pockmark sites be visited and sampled to analyse the character of any hydrocarbons emanating or residing in these features.

2. As part of this study of surface seepages, it is recommended that a hydrocarbon gas "sniffer" study be conducted in Hecate Strait. The instrumentation for this activity is substantial. The Australian AGSO have such a system, and we have been in contact with them to possibly arrange use of their system.

3. If Mesozoic source rocks are found on northern Vancouver Island, these should be analysed for their conventional geochemical source rock parameters (%TOC, RockEval-6, %Ro, etc.) If appropriate good samples should be used for kinetic maturation studies to characterize the generation profile of these source rocks.

4. Surface Geochemistry using sorbed gas characterization of surficial sediments of the Hecate Strait. This is a common exploration approach to map the geochemical expression of the subsurface, and to make predictions on the type and maturity of generated hydrocarbons. Such surveys potentially have the additional bonus of providing samples for environmental assessment work in the Hecate Strait. The primary limitation on this work is the poor surficial sediment quality. The regions of interest typically have sandy sediments at the surface, which are not suited to surface geochemistry. This places strong restrictions on the sampling locations, and needs to be considered beforehand.

2. Overall Project Objectives

Phase I. Broad-scale basin characterization

Creation of initial broad scale maps and petroleum system models for Hecate Strait showing definition and categorization of potential hydrocarbon generation areas of Queen Charlotte Basin.

Phase II. Detailed basin delineation

Creation of Petroleum System Model for Queen Charlotte Basin. This will show assessments of basin evolution, including the histories of tectonics, geology, sedimentation, geochemistry and maturation.

Creation of detailed maps / profiles for QCB, showing features such as

1. Potential source rock types
2. Recent maturities
3. Probable migration fairways
4. Probable traps

This study seeks to define the most probable sectors of petroleum formation in the Queen Charlotte Basin (QCB), underlying Hecate Strait and Queen Charlotte Sound. The purpose is to integrate the available geophysical, geologic and geochemical information for the region into a unified assessment using our Petroleum Systems Modeling.

This 12-month, 2-phase study provides an initial delineation of the Queen Charlotte Basin as to its degree of petroleum formation. It provides assistance in the definition of the possible location and timings of accumulations of hydrocarbons. One goal of this study is to assist in reducing the footprint of likely interest in Hecate Strait and Queen Charlotte Sound. This work will identify sectors in there that may require follow-up work, i.e., surface sediment/geochemical surveys, 2-D or 3-D seismic, etc.

2.1 Phase I Objectives (Broad-Scale Basin Characterization)

Phase I will provide a preliminary collation and synthesis of existing information for the Queen Charlotte Basin region. This will include an analysis of the regional geophysical and geochemical information to map the potentially hydrocarbon prospective generative areas in the basin. The output will be a "first-cut" mapping of the petroleum generation. Due to the lack of reliable information on Mesozoic sequences in the QCB, Phase I will concentrate more on the Paleogene and Neogene sequences of the basin. Although marine units are described for limited sections in the Cenozoic, most of the potential source rocks are comprised of Type III kerogens, and hence largely gas prone. We recognize that older units in the basin, such as the late Triassic and Jurassic, may have suitable marine source rocks (Type II kerogen) for the substantial generation of oil and gas. As such, they are important to the petroleum situation of the QCB and therefore we include these units in our Petroleum Systems Model. However, these Mesozoic units have not been drilled in the basin and are only known from small outcrops on the Queen Charlotte Islands (QCI). Furthermore, the seismic, stratigraphic and lithologic information on the Mesozoic available to us at this point is limited. As a consequence our assessment of the Cenozoic sequences will be more reliable than for the Mesozoic.

2.2 Phase II Objectives (Detailed Basin Delineation)

Phase II will provide detailed assessments of the areas of interest defined in Phase I. This includes smaller-scale tectonics, geology, sedimentology, geochemistry and hydrodynamics to estimate:

a) Source rock deposition – e.g., types, areal extent
b) Hydrocarbon generation
c) Timing of migration– probable migration fairways (2D)
d) Types and location of petroleum plays expected (2D)

The work will be conducted in close consultation with the Offshore Oil and Gas Branch to ensure that the needs, goals and formats of the Ministry of Energy and Mines are considered on an ongoing basis. In addition, this project will identify questions, aspects or issues that may need addition resources or effort to resolve.

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3. Background Information

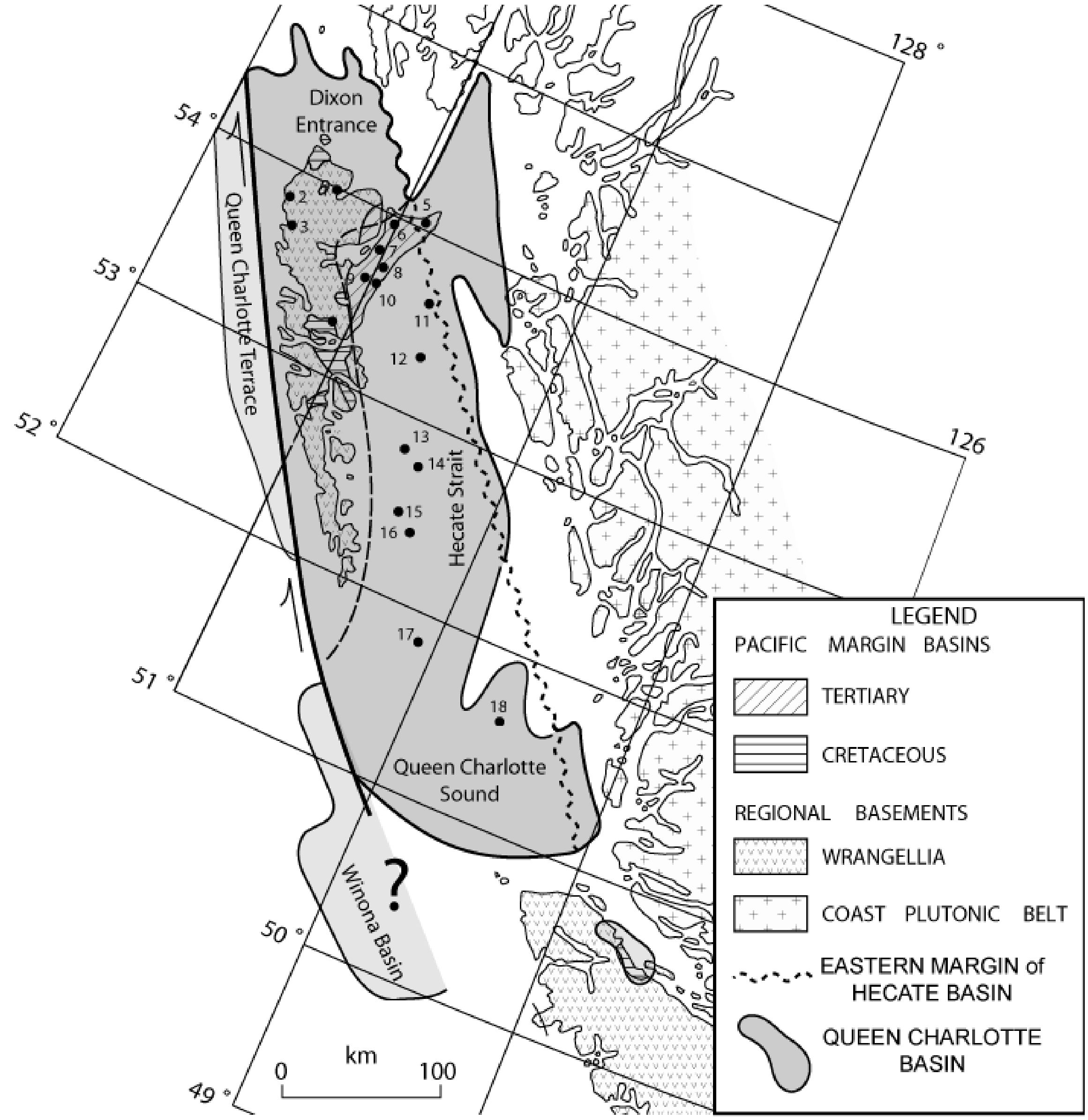
3.1 Physical Background

Petroleum offshore British Columbia potentially represents a tremendous energy resource and opportunity for the people of the province. However, the possible incorporation of this resource into the province's inventory of oil and gas has significant challenges. These certainly include safe and economic identification, discovery and production, as well as appropriate assessments of the environmental, economic and social implications and responsibilities embedded in such activities.

One of the most prospective petroleum sector offshore B.C. is the Queen Charlotte Basin. This basin underlies Dixon Entrance, Hecate Strait, Queen Charlotte Sound and parts of the Queen Charlotte Islands (QCI) in a region bound by the Queen Charlotte Fault, the northern tip of Vancouver Island, and the Coast Plutonic Complex (Figure 2). The QCB occupies a large shallow marine area, approximately 80,000 km^2 (500 km long, 150 - 200 km wide). This offshore basin is Tertiary in origin, and is the largest of its kind along Canada's West Coast. Although it is relatively young in geologic terms much of it formed on the old Wrangel terrane, which has undergone extensive tectonic restructuring since the Triassic.

Table 3. List of wells drilled on and offshore QCB.

Onshore Wells	
1	Bow Valley et al. Naden Harbour b-A27-J
2	British Columbia Coal Co. Tian Bay
3	Union Port Louis c-28-L
4	Queen Charlotte No. 1
5	Richfield-Mic Mac-Homestead Tow Hill d-93-C
6	Richfield-Mic Mac-Homestead Masset c-10-I
7	Richfield-Mic Mac-Homestead Nadu River b-69-A
8	Richfield-Mic Mac-Homestead Cape Ball d-41-L
9	Richfield-Mic Mac-Homestead Gold Creek c-56-H
10	Richfield-Mic Mac-Homestead Tlell c-56-D
Offshore Wells	
11	Shell Anglo South Coho I-74
12	Shell Anglo Tyee N-39
13	Shell Anglo Sockeye B-10
14	Shell Anglo Sockeye E-66
15	Shell Anglo Murrelet L-15
16	Shell Anglo Auklet G-41
17	Shell Anglo Harlequin D-86
18	Shell Anglo Osprey D-36



QUEEN CHARLOTTE BASIN WELLS

1 - Bow Valley et al. Naden Harbour b-A27-J
2 - British Columbia Coal Co. Tian Bay
3 - Union Port Louis c-28-L
4 - Queen Charlotte No. 1
5 - Richfield-Mic Mac-Homestead Tow Hill d-93-C
6 - Richfield-Mic Mac-Homestead Masset c-10-I
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8 - Richfield-Mic Mac-Homestead Cape Ball d-41-L
9 - Richfield-Mic Mac-Homestead Gold Creek c-56-H
10 - Richfield-Mic Mac-Homestead Tlell c-56-D
11 - Shell Anglo South Coho I-74
12 - Shell Anglo Tyee N-39
13 - Shell Anglo Sockeye B-10
14 - Shell Anglo Sockeye E-66
15 - Shell Anglo Murrelet L-15
16 - Shell Anglo Auklet G-41
17 - Shell Anglo Harlequin D-86
18 - Shell Anglo Osprey D-36

Figure 2. Location map of Queen Charlotte Basin (Dixon Entrance, Hecate Strait and Queen Charlotte Sound) showing 18 previous drillholes (modified from Hannigan et al., 2001).

To date, 18 exploration wells have been drilled (Listed in Table 3, shown in Figure 2) in the QCB, with 8 offshore in Hecate Strait and Queen Charlotte Sound, and 10 on Graham Island. These wells, combined with the regional geophysical seismic studies and land-based geology are the basis of prospectivity projections (Dietrich, 1995; Hannigan et al., 1998 & 2001). Their estimates are based on the presence of potential source rocks, abundant reservoir strata, numerous structural traps, and common occurrence of oil and gas shows.

The Neogene portion of the Queen Charlotte Basin is expected to contain 80% of the region's total petroleum resource volume and nine of the ten largest fields (Hannigan et al., 1998). Geographically speaking, most prospective areas are defined in southern Hecate Strait, followed by Queen Charlotte Sound, eastern Graham Island, northern Hecate Strait and Dixon Entrance (Figure 2). High potential exists for southern Hecate Strait based on abundant Neogene reservoir strata, numerous large structural features, and presence of Neogene and Jurassic source rocks. In addition, western Graham Island and adjacent shelf areas have some potential targets, but very little petroleum potential is expected overall in the onshore/inter-island areas of the southern QCI and adjacent Pacific continental shelf.

3.2 Resource and Economic Background

Based on previous studies and exploration data, the Queen Charlotte Basin is expected to have substantial petroleum accumulations. These assessments are speculative, even though the process to arrive at the numbers involves industry "best practice" techniques. The estimate of *in place* oil has a statistical center (50 percentile probability) around 1.5 billion cubic meters (m^3) or 9.8 billion barrels (bbl), e.g., Hannigan et al. (1998) (Figure 3). The estimate of *in place* natural gas is around 730 billion cubic meters (m^3) or 26 trillion cubic feet (tcf). Potential recoverable reserves are generally projected to be lower, possibly 400 million cubic meters (m^3) or 2.5 billion bbl oil and 550 billion cubic meters (m^3) or 20 tcf gas (Tables 4 and 5).

In a subsequent publication, Hannigan et al. (2001) predict that the QCB region is expected to have 103 oil fields and 120 gas fields. The largest oil field size is predicted to be about 440 million barrels, with 6 fields over 100 million barrels, i.e., 1.3 billion bbl in total in the 6 largest fields. The largest gas field is predicted to be 2.7 tcf, with 14 fields over 500 bcf, i.e., 12 tcf in the top 12 fields.

In comparison with the estimated B.C. onshore reserves of 8.2 billion bbl oil and 73 tcf gas, the potential recoverable reserves for the QCB of 2.5 billion bbl oil and 20 tcf gas are considerably lower. Figure 4 compares the estimated onshore and offshore resources (both proven and unproven) for British Columbia, including the four largely unexplored B.C. offshore basins. Using current direct economic valuation, the offshore oil and gas translates into approximately $49 billion and $83 billion, respectively, as compared to $41 billion and $146 billion for onshore oil and gas. This sums to a direct B.C. total (on and offshore) of $320 billion. Over a 50 yr production period this partitions into $6.4 billion per year. B.C. Petroleum revenues have been increasing steadily over the past

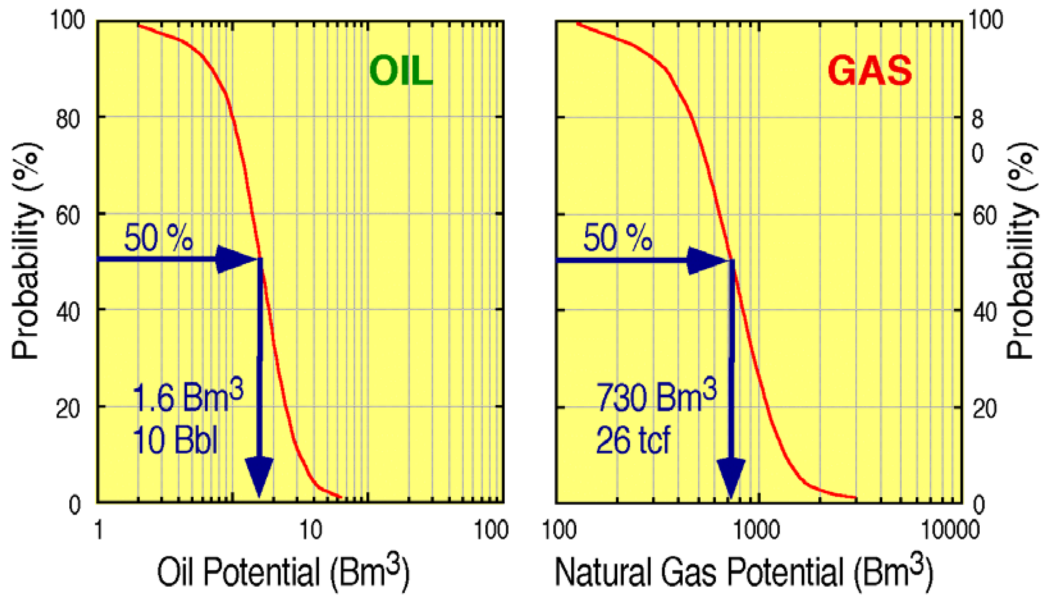

Figure 3. Basic hydrocarbon potential of QCB oil and gas based on estimated in-place oil and gas potential by Hannigan et al., (1998 and 2001). These numbers need adjusting for actual recoverable reserves and market values, once such information is available.

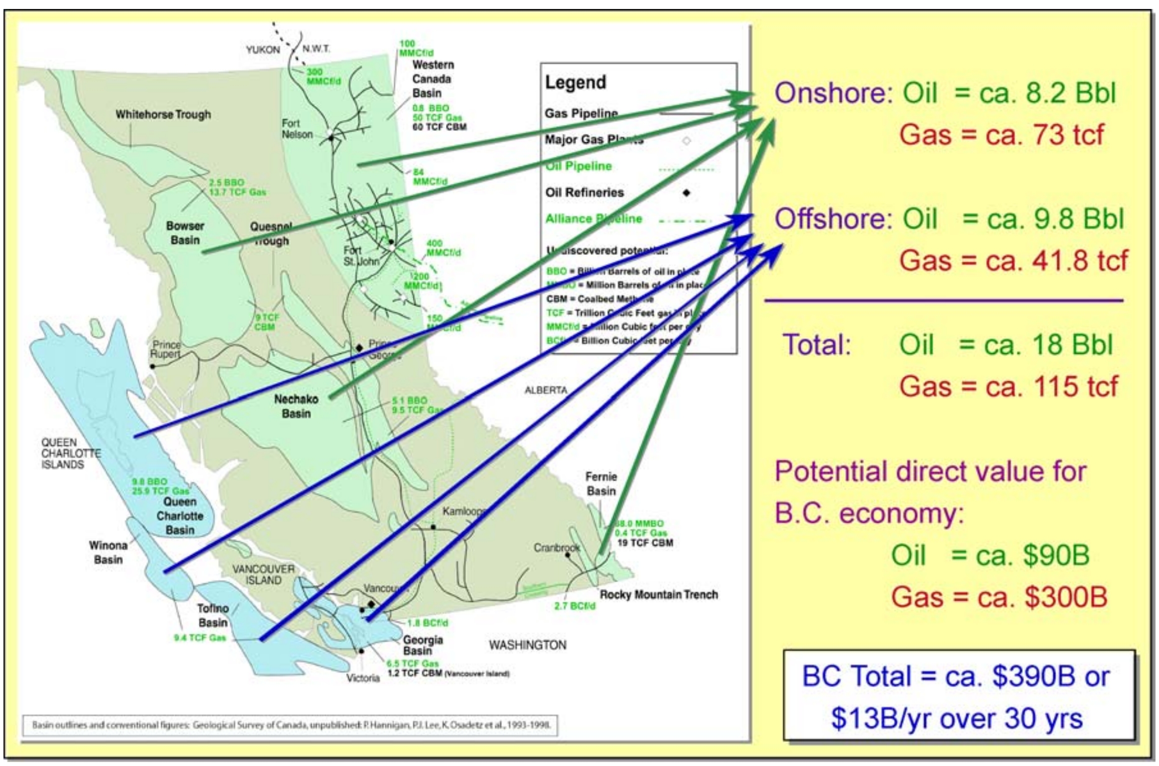

Figure 4. Comparison of B.C. onshore and offshore resource potentials.

decades, as shown in Figure 5. In 2003, the onshore revenue generated from oil and gas was $2.11 billion, which represents substantial growth in the past 5 years. Using the combined estimated onshore and offshore resources, the revenue for BC could increase substantially up to approximately $6.4 billion/yr).

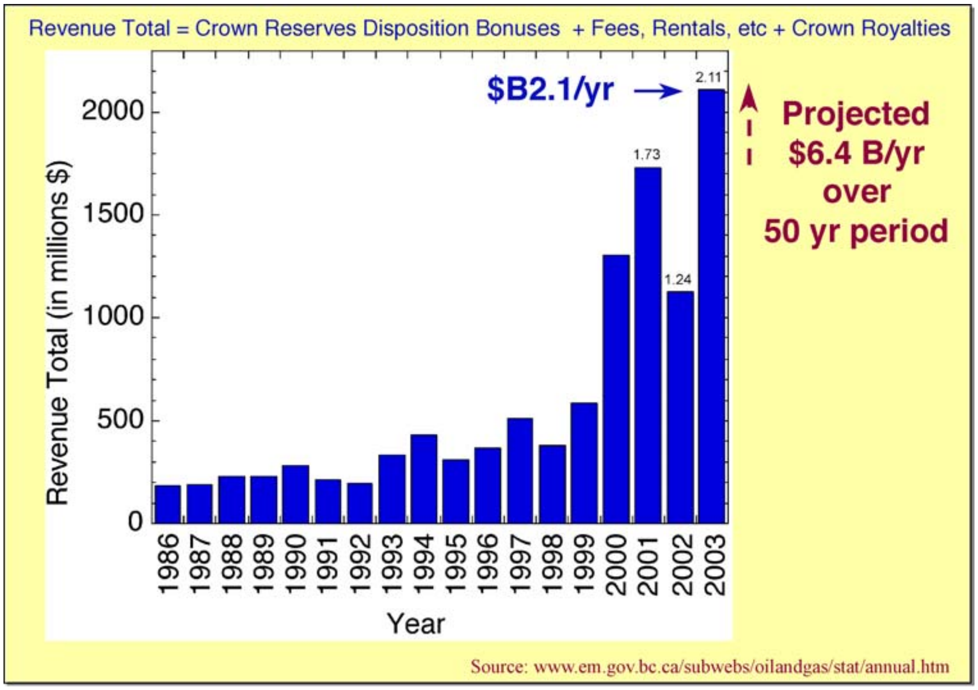

Figure 5. B.C. onshore and offshore petroleum revenue history and projections.

Based on National Energy Board figures, these potential oil and gas resources are significant on a national scale as shown in Tables 4 and 5. However, whether or not these estimates are realistic will require considerably more exploration effort.

Estimates of oil and gas in the QCB compared with the east coast Jeanne d'Arc Basin (JdA) are difficult to make. This is certainly due to the differences in the stages of exploration between the two regions, for example offshore well coverage in QCB is ca. 8 well/80,000 km^2, or 1:10,000 whereas for the JdA the well/area ratio is approximately 1:700. Other differences include greatly different geologic situations and available supporting information.

First estimates indicate that the B.C. offshore has greater oil (9.8 vs. 4.6 billion bbl) and gas (42 vs. 18 tcf) potential than the Jeanne d'Arc Basin (Figure 6), but one must not confuse recoverable reserve with potential resource estimates. The latter are generally much lower.

Table 4. Comparison (Discovered Marketable Resources)

Location	Oil (10^6 m^3)	Natural Gas (Tcf)
QCB (potential)	400*?	20*?
A. Canada	4,555	198
B. WCSB	2957	159
C. Frontier	528	33
D. BC conventional	129	20

*? = Speculative estimation

Table 5. Comparison (Ultimate Resources)

Location	Oil (10^6 m^3)	Natural Gas (Tcf)
QCB(potential)	730*?	26*?
A. Canada	9,177	733
B. WCSB	3,623	335
C. Frontier	4,255	303
D. BC conventional	184	50

*? = Speculative estimation

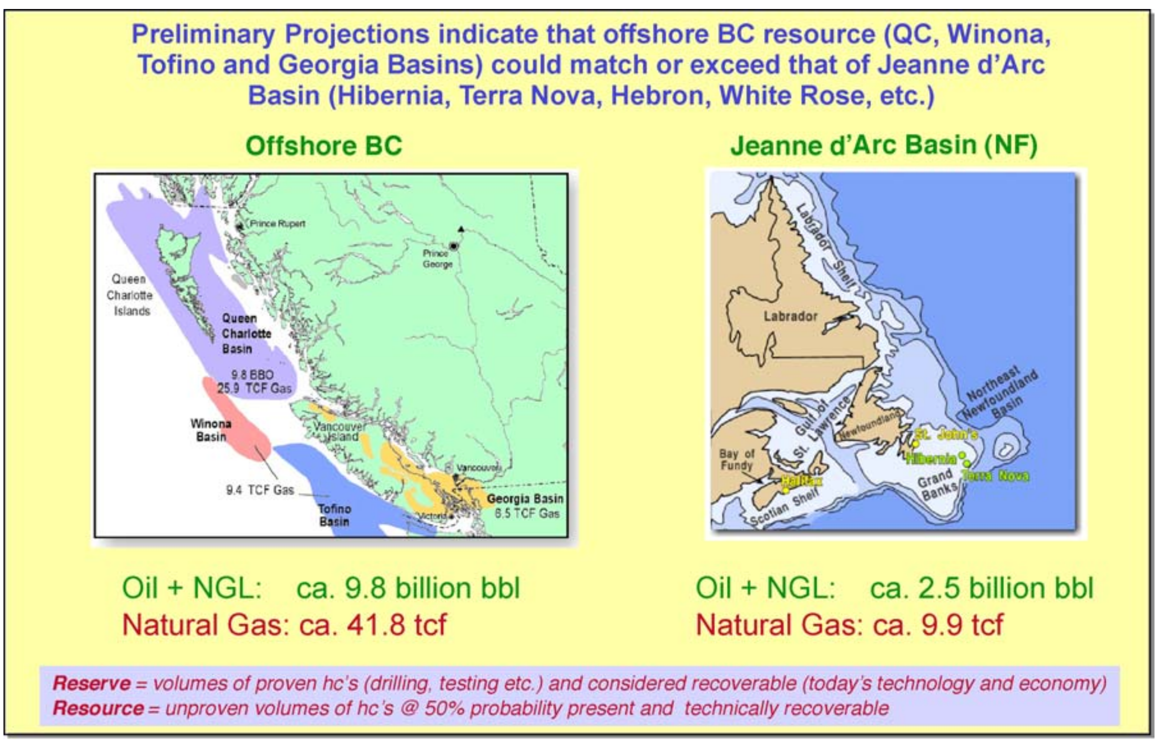

Figure 6. Comparison of BC and Jeanne d'Arc (NFLD) offshore petroleum projections.

3.3 Geologic Framework and Background

The Tertiary Queen Charlotte Basin is located immediately inboard of the Pacific - North American plate boundary. From north to south Dixon Entrance, Hecate Strait, and Queen Charlotte Sound have experienced slightly different sedimentary and tectonic evolutions. Figure 7 shows the generalized stratigraphy after Dietrich (1995). A network of fault-bound sub-basins in Hecate Strait and Queen Charlotte Sound contain up to 5 km of siliciclastic rocks: sandstones, siltstones and conglomerates with some coals which are known as the Skonun Formation (refer to Appendix C for details). Lithology varies rapidly in depth in all the wells drilled; facies vary gradually from non-marine to marine with time and include alluvial fan, fan delta, delta plain shelf and slope settings (Higgs, 1991; Dietrich et al., 1993). Based on the reflection data the Skonun has been broadly divided into syn-rift and post-rift successions; the division is time transgressive. Fossils indicate Miocene and Pliocene ages but some layers, especially the non-marine, contain few identifiable fossils. At many locations, the basal sediments either interfinger or overly extensional basaltic rocks of the Masset Formation (Hickson, 1992; Hyndman & Hamilton, 1993). Masset rocks on Graham Island have yielded ages of 35-12 Ma; most fall between 25-20 Ma. Unfortunately no reliable dates are available from basalts drilled in the wells. 25 Ma is usually taken to be the age of rift initiation, but rifting could be time transgressive. Tectonic models of basin formation and evolution are discussed below in Section 4.

Poor age control in the base of the offshore wells makes thermal modeling difficult. Currently age of rifting is based on dates from basalts in the northwestern section of the Basin (Graham Island) and may not be representative of the entire basin. Sub-basins may have initiated at different times. Syn-rift sediments in Queen Charlotte Sound are largely lower Miocene whereas in Hecate Strait substantial thicknesses of syn-rift sediments are lower and upper Miocene. Rifting may have started in the south and progressed northward but without better dating throughout the basin, we cannot conclude this.

Mesozoic potential source and reservoir rocks, the Sandilands and Ghost Creek formations from the Kunga and Maude groups, are exposed on the Queen Charlotte Islands. At least the Sandilands Formation is likely to occur in most parts of the Wrangell Terrane, underlying Hecate Strait and Queen Charlotte Sound (Cameron & Tipper, 1985, Woodsworth, 1988, Thompson et al., 1991, and Bustin & Mastalerz, 1995). Both the Sandilands and Ghost Creek formations comprise significant organic-rich potential petroleum source rocks in the region, which reach up to 600 m in thickness with TOC up to 6.1%, comprising oil-prone Type I and oil and gas-prone Type II kerogens with HI values ranging up to 589 mg HC/g C_{org} (Bustin & Mastalerz, 1995). Organic-rich shales with 5 to 10% TOC occur in beds up to 10m thick (Dietrich, 1995). An overall regional north to south degree of organic maturation characterizes the Phanerozoic stratigraphic succession in the Queen Charlotte Islands (Vellutini and Bustin, 1991).

Cretaceous fossils have also been identified at the base of the Tyee and Sockeye E-66 wells (Shell Canada Ltd., 1968a and 1968c).

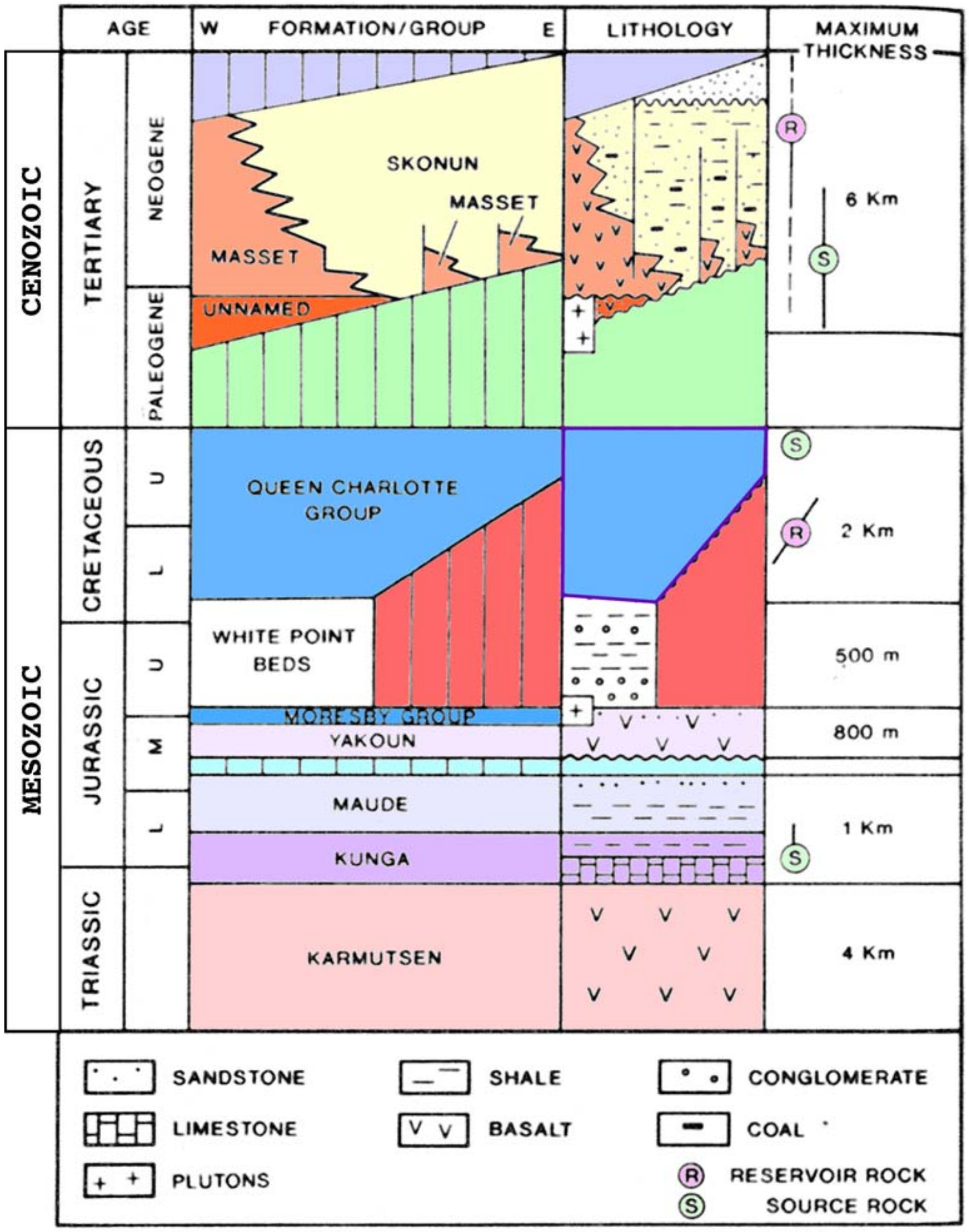

Figure 7. Generalized stratigraphy of Mesozoic (Triassic, Jurassic and Cretaceous) and Cenozoic (Tertiary) of QCB (after Dietrich, 1995).

Most of the oil occurrences so far encountered in the region appear as surface seeps in Tertiary volcanic rocks of the Masset Formation (Hamilton & Cameron, 1989). They can be correlated to a Tertiary source (Fowler et al., 1988, Snowdon et al., 1988). Oil strains in subsurface samples encountered in Tertiary sandstones within the Sockeye B-10 well seem generally related to a Lower Jurassic source (Bustin & Mastalerz, 1995). Generally poor hydrocarbon potential is proposed for the Upper Jurassic / Cretaceous succession which mainly comprises Type III kerogens (Dietrich, 1995).

Within the Skonun syn-rift and the post-rift succession organic rich mud rocks and coals of highly variable hydrocarbon potential occur. TOC varies from 0 to 30% with higher values in the rift section (Bustin, 1997); average values remain low at about 1%. In general these strata comprise Type III kerogens with low hydrogen indices (HI < 300 mg HC/g C_{org}) indicating good gas and fair oil source potential (Dietrich, 1995, Bustin, 1997). Basic maturation models, based on the assumption of a constant paleo-heat flow have been presented by Bustin (1997) for these Tertiary source rocks. They proposed that the syn-rift succession reached the oil window between 27 and 16 Ma ago, is now overmature and that some parts of the post-rift succession are in the oil window today.

Three conceptual plays have been presented by Dietrich (1995), involving Cretaceous and Neogene sandstone and conglomerate reservoirs and Jurassic and/or Tertiary source rocks. Proximity of Cenozoic strata to Mesozoic source rocks, faulting, thermal maturation, reservoir, and cap rocks all occur within the QCB. Of interest is the reoccurring interbedded nature of the lower to middle Miocene strata that can offer reservoir and seal conditions. This is in addition to source materials such as from the coals and carbonaceous materials. Hydrocarbon shows were noted in Sockeye B-10 (3140-3298 ft., unit 8 Appendix C) and bitumen in unit 6 (Appendix C). Sandy intervals such as unit 9 in the Tyee well may provide important reservoir rocks.

3.4 Background on Petroleum System Models

Basin modeling comprises numerical simulations of geologic structures through time, based on physical and chemical reactions. In the petroleum industry basin modeling has already become a widely used tool to evaluate hydrocarbon potential, and it is widely used to determine subsidence and temperature histories. Furthermore it can be applied to remote and unknown areas, where only sparse information is available, as in the QCB. It is based on a number of geological concepts, which include backstripping, the evolution of thermal parameters, temperature distribution within the sedimentary column, crust and mantle, and kinetics of petroleum generation.

Numerical modeling of petroleum systems developed in the early 1980's and has improved greatly in recent years due to advances in organic geochemistry, multi-phase fluid flow models, numerical methods and computer performance. Basin modeling has become an essential tool in the exploratory strategy of petroleum companies because it provides a dynamic, objective and integrated view of processes such as sedimentation, compaction, fluid flow, heat transfer, source-rock maturation, petroleum expulsion, migration and accumulation.

Basin modeling allows explorationists to simulate basin evolution and petroleum generation, expulsion and migration in a physically- and geochemically consistent way.

More importantly, it also provides significant insights into fundamental questions such as:

- Where are the effective source rock kitchen areas?
- What is the timing of the processes of petroleum generation, expulsion and migration for each source rock?
- What are the possible migration pathways from source rocks to reservoirs?
- What is the role of faults as migration pathways?
- How effective must drains and seals be in order to cause a commercial accumulation?
- What are the expected oil and gas compositions in a petroleum trap?

Results from basin modeling studies have been used to better understand petroleum systems in and, most important of all, to identify the possibilities and risks concerning new exploration targets. Petroleum System Software is generally applied to compute the evolution of:

- source-rock maturation
- hydrocarbon generation
- hydrocarbon expulsion
- hydrocarbon migration
- hydrocarbon accumulation
- petroleum phase and composition

3.4.1 Sedimentation and compaction

In 1D as well as in 2D basin modeling the back-stripping of sediments (McKenzie, 1978; Steckler & Watts, 1978; Sclater & Christie, 1980) is used to evaluate burial evolution and basin subsidence from the stratigraphic record. It accounts for basin subsidence due to tectonic movements and sedimentary loading, variations in formation thickness and porosity, caused by compaction, and for paleo-bathymetry. Since back-stripping attempts to correct the stratigraphic record for the effects of loading in the past, the original thickness during deposition of each defined formation is computed as the result of sediment decompaction, according to its initial porosity. The initial porosity is determined from a porosity versus depth law, given for each lithology. For this process of back-stripping a paleo-water depth profile has to be defined for each time-step of the model, to construct its geometric evolution.

3.4.2 Subsidence and uplift

Vertical tectonic movements, such as subsidence and/or uplift, can influence sedimentation, because depositional space is created or destroyed. As temperature and pressure distribution are affected by these processes, maturation of the organic matter is also influenced. In the models presented here uplifted formations (due to erosion) remain compacted until the maximum burial depth is reached again and exceeded by the deposition of overlying sediments.

3.4.3 Thermal concept

Besides influencing subsidence, temperature is one of the most important factors controlling chemical reactions and related fluid transport. It is therefore of major importance for any basin modeling study, which evaluates hydrocarbon maturation and migration. Temperature distribution and its evolution through time within a sedimentary basin is the result of heat transfer from the deep, partly molten mantle below the lithosphere toward the atmosphere, plus the heat derived from radiogenic elements within the lithosphere itself. One of the most important parameters is therefore the heat flow through the sedimentary column, and its evolution through time.

As there is no direct measurement of the paleo-heat flow through the sedimentary basin, theoretical models have to be employed to constrain its evolution. Paleo-heat flow is influenced by the temperature of the earth's surface and the heat flow encountered at the base of the sedimentary column, which is given by the sum of the radiogenic heat flow, generated within the crust, and the basal heat flow at the bottom of the crust. Several publications have dealt with temperature distribution within the crust and the mantle, and the resulting heat flow out of the basement (McKenzie, 1978; Royden & Keen, 1980; Welte & Yuekler, 1981; Tissot & Welte, 1984; Royden, 1986; Allen & Alen, 1990; Hermanrud, 1993; Yalcin et al., 1997). Wygrala (1989) and Barker (2000) investigated the influence of the surface temperature of the sediments, either with the atmosphere, or with water on burial heating models; these effects have been accounted for in the models presented here.

Heat flow is measured as the amount of heat crossing a given area per unit time, either due to convective or conductive transport mechanisms. While convective heat transport is the dominant mechanism in the mantle, and most probably drives the lithospheric plates, conductive heat transport dominates within the crust (McKenzie et al., 1980). Convective heat transport, however, exists in the crustal layer as well, due to circulating fluids and/or magmatism, but it is less effective and/or restricted to short periods of time, respectively. Under the assumption of negligible convection, the heat flow q is defined as:

$$q = \lambda \cdot \frac{\delta T}{\delta z} \; [W/m^2] \tag{1}$$

where λ [W/m • K] is the thermal conductivity and $\Delta T/\Delta z$ [K/m] is the thermal gradient, with T = absolute temperature and z = distance. The temperature distribution within the sediments depends on the above-defined thermal parameters and the sedimentation rate and the thickness of the sedimentary column. As long as the sedimentation rate is less than 100 m/Ma and the sedimentary column is less than 6000 m thick, the heat flow may be considered as uniform through the sedimentary column (Beicip-Franlab, 1989).

These so-called steady state conditions, where the temperature can be readily deduced from the above correlations have to be separated from transient state conditions with higher sedimentation rates which create a blanketing effect. Due to the fact that rapidly deposited matter is not in thermal equilibrium with the sediments and the basement, the thermal inertia of the crust and the mantle would have to be considered (Beicip-Franlab, 1989).

The sediments' thermal conductivity λ is a function of the water and matrix conductivity, pursuant to equation:

$$\lambda = \lambda_s \left(\frac{\lambda_w}{\lambda_s}\right)^{\Phi} [W/m \cdot K] \tag{2}$$

with λ_w = water thermal conductivity, λ_s = sediment matrix thermal conductivity, and Φ = porosity.

If heat flow is uniform, contrasts in conductivity will affect the geothermal gradient in the individual layers, causing a so-called dogleg along its slope. The local geothermal gradient G_l, which is necessary to be calculated during the basin modeling, is the temperature derivative with depth, according to equation:

$$G_l = \frac{\delta T}{\delta z}(z) \ [^\circ C/m] \tag{3}$$

The average geothermal gradient G_a at depth z is as per Eq. 4

$$Ga(z) = \frac{T(z) - T(o)}{z} \ [^\circ C/m] \tag{4}$$

with T_0 = surface temperature.

Contrasts in conductivity can arise with lithologic changes (e.g. salt, dolomite or highly porous clays), or with water flow of hydrothermal or hydrodynamic origin, influencing heat flow patterns and causing temperature variations in the vicinity of permeable layers. Igneous activity can also influence heat flow, but if the igneous products are not voluminous, the temperature changes and subsequent maturity modifications of hydrocarbons are not detectable farther than a few tenths of meters from the intrusion itself, due to their short time of duration (Beicip-Franlab, 1989).

The temperature at the interface of sediment/air or sediment/water depends on changes in the global climate (Frakes et al., 1992), changes of the paleo-latitude due to plate tectonic movements (Savin, 1977; Wygrala, 1989; Barker, 2000), and vertical displacement due to regional tectonics (uplift/subsidence). Furthermore water currents, transporting either cold or warm water masses, and their evolution through time have to be considered. Beck (1977) and Barker (2000) stated that changes in mean annual surface temperature penetrate several kilometers deep into the crust and can significantly influence hydrocarbon maturation.

Radiogenic crustal heat flow

Heat flow, caused by the heat production of radiogenic elements (^{238}U, ^{235}U, ^{232}TH, ^{40}K) in the crust is highly variable (less than 10mW/m² in Niger (Morgan, 1985) to 75mW/m² in young granitic crust (Beicip-Franlab, 1989)). It depends on the crustal thickness, its age, and the type of rock.

Radiogenic heat production

The radioactivity in the crust is supposed to decrease with depth in an exponential way, whereas it is assumed to be uniform with depth in the mantle (Allen & Allen, 1990). During modeling the radiogenic depth decay (RDD) acts as a depth scaling parameter for the radiogenic heat production in the crust with reported values in the range from 5 to 20 (Morgan, 1985). For the Wrangel terrane underlying the QCB a moderate radiogenic derived heat flow of 22 mW/m² is assumed for the 1D models presented here, accounting for its structure and its age.

Paleo- basal crustal heat flow

No direct method exists to calculate the paleo-heat flow. Numerous models have been presented to estimate its evolution through time, dependent on the geologic environment.

A simple model for the development and evolution of sedimentary basins after an instantaneous and uniform (pure shear) rifting was presented by (McKenzie, 1978). According to this model thermal subsidence and heat flow only depend on the amount of stretching. Surface heat flow is calculated under the boundary conditions of parameters given in Table 6 according to Equation 5:

$$F(t) = \frac{kT_1}{a}\left\{1 + 2\sum_{n=1}^{\infty}\left[\frac{\beta_u}{n\pi}\sin\frac{n\pi}{\beta_u}\right]\exp\left(-\frac{n^2 t}{\tau}\right)\right\}, \qquad (5)$$

with B_u is uniform crustal/lithospheric stretching factor and the background heat flow kT_1/a originally given in HFU, but modified here to units of mW/m^2.

Table 6 Values of parameters used in Eq. 5 (after McKenzie, 1978).

a	thickness of lithosphere	125 km
T_1	temperature of asthenosphere	1333 °C
τ	thermal time constant of the lithosphere	62.8 Ma
kT_1/a	background heat flow	33 mW/m^2

3.4.3 Maturation concept

A parameter often used for calibration of a basin model is vitrinite reflectance. It is an indicator of the maturity of organic material and acts as a control parameter for the burial and thermal histories. Vitrinite reflectance is defined as the percentage of light reflected by a given vitrinite particle and given in units of $\%R_O$. On the one hand it can be measured, using the organic material collected in wells, and on the other hand vitrinite reflectance is calculated during basin modeling, according to the widely used Easy$\%R_O$ algorithm (Sweeney & Burnham, 1990). This algorithm is based on chemical kinetics and uses an Arrhenius first-order parallel-reaction approach with a distribution of activation energies. It offers the ability to calculate a $\%R_O$ profile as a function of time for a given stratigraphic level if the time-temperature history is known. For comparison with borehole data $\%R_O$ profiles as a function of depth can be calculated, when the model is applied to multiple stratigraphic layers, as is done by basin modeling software.

3.4.4 Petroleum generation kinetics

The kinetics of petroleum generation is handled by the scientific approach of reaction kinetics, in which the Arrhenius law is used to express the increase of reaction rate with temperature. Primary cracking is treated by several parallel independent reactions, in which the rate of petroleum generation is proportional to a rate constant (k), which increases with temperature, according to the Arrhenius law:

$$k = A \cdot e^{-E/RT} \quad (6)$$

with k is rate constant s^{-1}, A is Arrhenius factor, E is activation energy (kJ/mol), R is the gas constant (0.001987 kJ/mol°K), and T is absolute temperature (°K).

While the same Arrhenius factor is used for all primary reactions, each reaction has its own activation energy. The higher the activation energy, the higher is the required temperature to generate oil in a given time interval. Together with the initial potential, which has to be specified for each individual reaction of each type of kerogen, these kinetic parameters characterize the model of primary cracking. The sum of the initial potentials equals the HI, determined according to the Rock-Eval method.

Although some of these parameters are either known or can be reasonably assumed, there are uncertainties in the values, which leads to uncertainties in the estimation in the level of maturity. Figure 8 is an Arrhenius Plot illustrating the influence of time, temperature and activation energy on the kinetic transformation of kerogen.

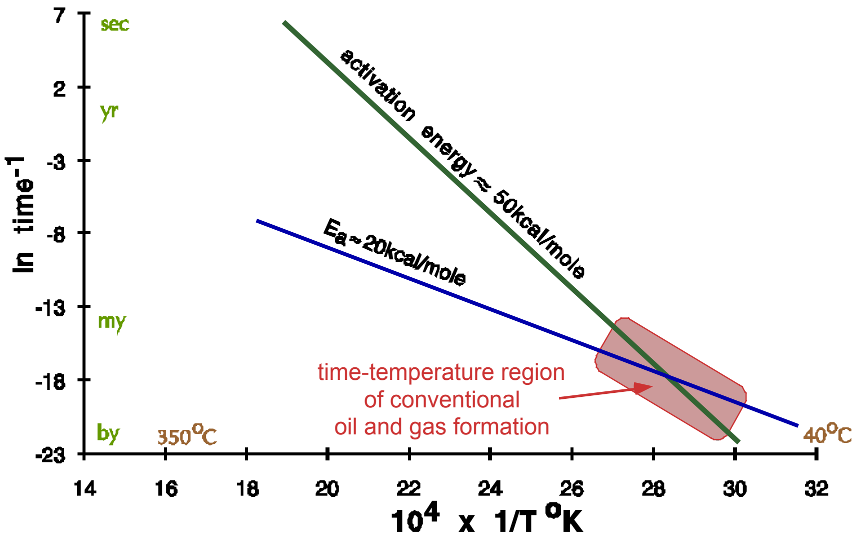

Figure 8. Arrhenius plot showing the relationship between temperature and time on the maturation of kerogen (adapted from Snowdon, 2002)

Currently all three of the parameters in Figure 8 are poorly constrained in the Queen Charlotte Basin, i.e.,

1. Appropriate activation energy – depends on the types of organic matter, which are inadequately sampled and characterized, especially the Mesozoic sequences

2. Time and age constraints (see Stratigraphy, Section 5)

3. Temperature History (see Section 7.2)

One of our challenges in this project is to choose the most reasonable values for these parameters.

In an open system, expulsion of petroleum, created during the primary cracking process (e.g. transformation of kerogen to petroleum) is calculated and secondary cracking (e.g. progressive degradation of the liquid hydrocarbon fraction to gas and to a carbon residue) is only applied to the unexpelled petroleum (Forbes et al., 1991).

In pyrolysis experiments the above mentioned kinetic parameters have been determined for the standard types of organic matter (e.g. Ungerer & Pelet, 1987; Espitilité et al., 1988, and Ungerer at al., 1988). Due to the lack of source rock samples from the area under study the default kinetic parameters of the IES software package were used during this first phase of this study. A short description of the general kerogen types is given below:

Type I (lacustrine): The kinetic parameters for the primary cracking of Type I kerogen, with a dominant activation energy of 54 kcal/mol, have been derived from Rock-Eval experiments at various heating rates of a Green River shale sample, and have been tested by comparison with the trend of data in the Uinta basin. The parameters of secondary cracking have been calibrated with the autoclave pyrolysis data of (Evans & Felbeck, 1983).

Type II (marine): The model of primary cracking, with a dominant activation energy of 52 kcal/mol , is based on Rock-Eval data at various heating rates of a lower Toarcian shale of the Paris Basin. The parameters of secondary reactions have been derived from autoclave pyrolysis as presented in Ungerer et al. (1990).

Type III (terrestrial): The primary cracking parameters are those used by Forbes et al. (1991) for Brent and Åre coals from the Norwegian margin. These are slightly modified from those obtained from Rock-Eval pyrolysis of a Brent sample by Espitalité et al. (1988). Secondary parameters are based on autoclave pyrolysis data of the same Brent coal sample.

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4. Seismic reflection data

4.1 Geophysical Preparation

Considerable re-evaluation of the existing seismic data could still be undertaken. However, the scope of this work may be extensive and in many cases exceeds the framework of this project. Components that are outside the scope of this project are indicated in *italics* here.

- *Optimization of the processing sequence of the 1988 MCS reflection seismic data to resolve stratigraphy within the Tertiary and the Cretaceous sediments instead of the traditional overall crustal approach.*

- Transfer of the available MCS seismic reflection data computer-based seismic interpretation system to augment the present paper-section-based interpretation.

- Integration of available, older, single channel seismic reflection data into the 1988 MCS data set.

- Definition of a regional seismo-sequence stratigraphic concept with definition of multiple regional sedimentary units based on available MCS reflection seismic and well data.

- *Individual sediment thickness maps for the abovementioned sequences, at least for:*
    1. *Tertiary Skonun Formation, which comprises reservoir type sandstones*
    2. *Masset Formation, which holds the main part of the Tertiary source rocks and includes volcanic units, related to the initial period of extension in its lower part. This could include mapping of volcanic units related to initial extension phase during Tertiary.*

    This is largely dependent on obtaining reasonably good age control.

- *Definition /mapping of sediment transport pathways for various stages during the Mesozoic (bypassing).*

- *Processing attempt to improve the sub-basalt visualization of the pre-rift Upper Triassic /Lower Jurassic sediments which host the most prospective oil-prone source rocks known to occur in the area under study. The organic-rich Sandilands and Ghost Creek formations of the Kunga and Maude groups are supposed to underlie the Massett volcanic units related to the initial extension period.*

- Re-plot 1988 seismic reflection data to improve images of pre-rift sedimentary sequences.

- *Re-purpose the 1988 seismic reflection data for the first break data, which may contain useful information on basement velocities and depth. It is also hoped that such refraction seismic may assist in differentiating sedimentary Mesozoic from Neogene (Masset Formation) strata.*

- *Map the subsurface occurrence of Mesozoic source rocks to estimate their extension and thickness based on 1988 MCS reflection, wide angle reflection and refraction seismic data, as well as analysis of magnetic and gravity data. There may be some hope in interpreting shallow refractions recorded by in the reflection set. These arrivals are promptly erased but contain information on upper crustal velocities.*

- *Tectonic interpretation and general mapping of the main strike-slip extensional structures (along axis variations in fault strikes, mismatched stratigraphy on both sides, flower structures) with estimation of the amount of crustal stretching. Definition of individual sub-basins and zones of maximum sedimentary thickness within the syn- and post-rift succession of Hecate Strait and Queen Charlotte Sound. Estimation of crustal stretching is difficult and relies on assumptions of pre-existing crustal/lithospheric thicknesses.*

4.2 Tectonic Interpretations

Multi-channel seismic reflection data collected in 1988 imaged structures previously unknown to exist and necessitated new models of tectonic evolution for the Neogene Queen Charlotte Basin (Rohr and Dietrich, 1992).

In 1988, in spite of a variety of internal and external obstacles, 1,000 km of multi-channel seismic reflection data set were collected in Hecate Strait and Queen Charlotte Sound (Figure 9). While great detail is visible on each line, the lines cross different sub-basins and provide a spare regional framework for a tectonic interpretation. The resulting images are significantly better than what was possible during petroleum exploration in the late sixties (e.g., Figure 10). The lines were placed to tie as many wells as possible and were either parallel or perpendicular to the main strike of the basin. Unfortunately detailed information regarding isopachs was not available until after the survey so that lines do not necessarily image individual structures optimally (Figure 11a-c).

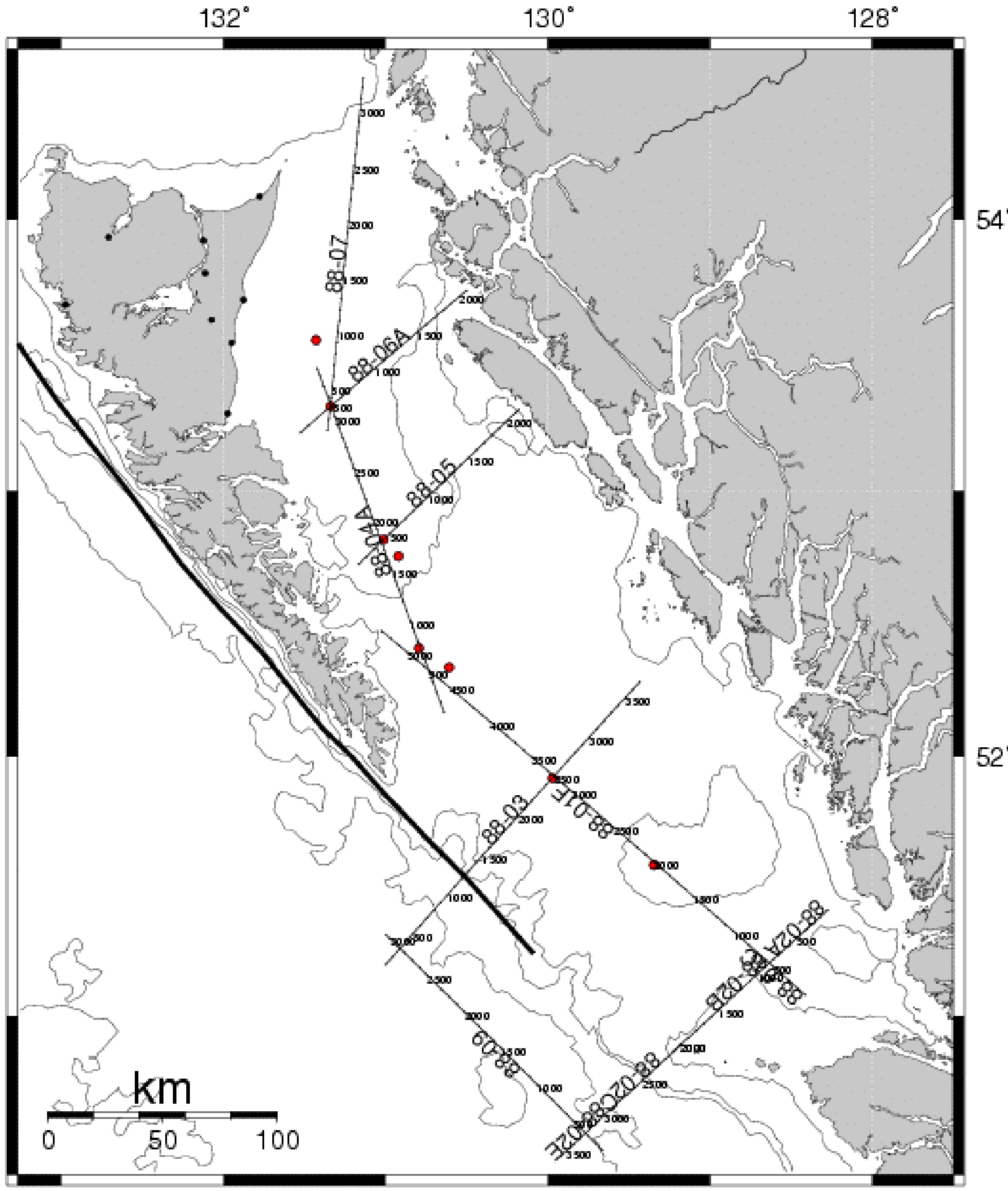

Figure 9. Map of Queen Charlotte Basin, showing location of seismic reflection lines acquired by Geological Survey of Canada in 1988 (Rohr and Dietrich, 1989).

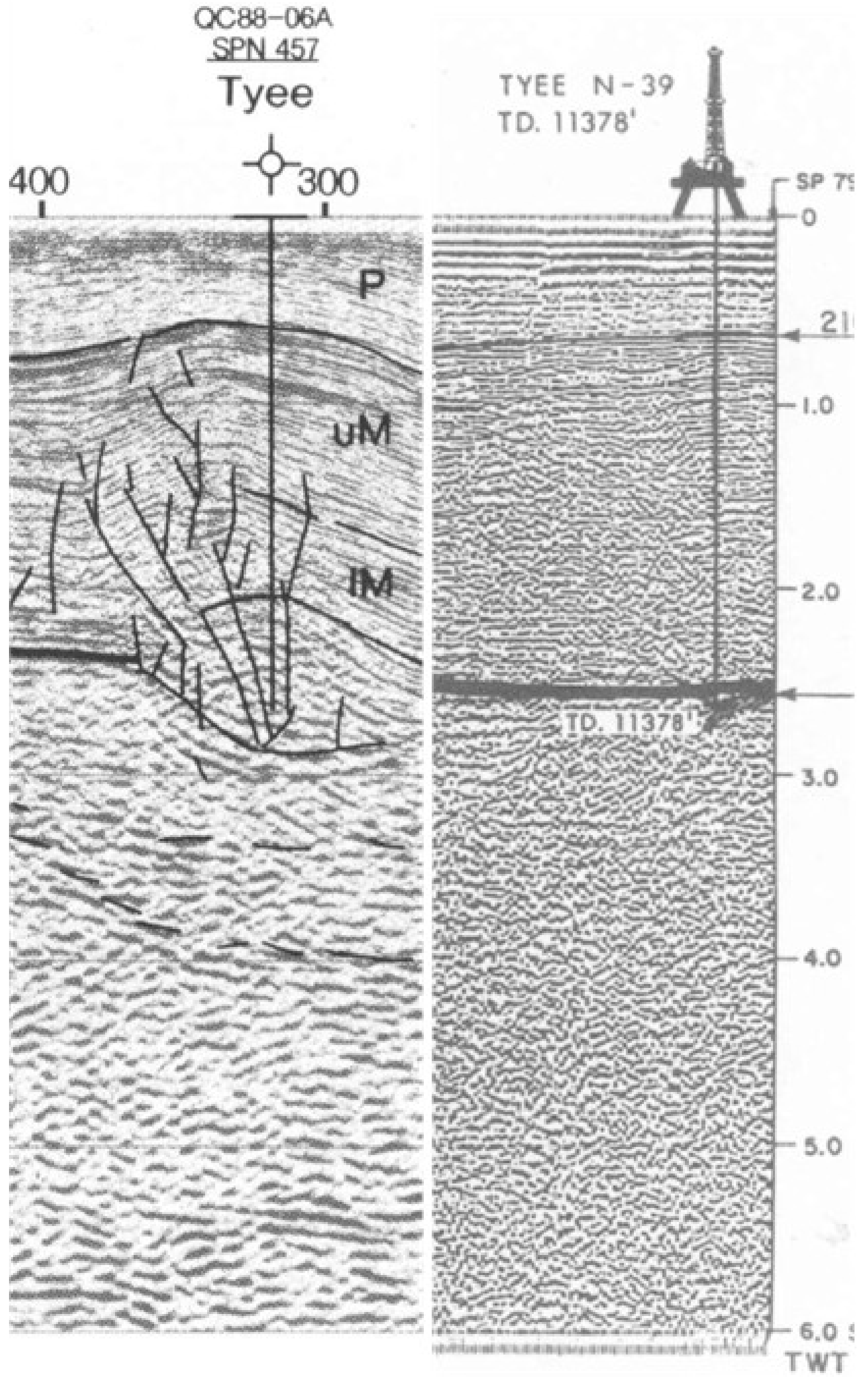

Figure 10. Comparison of multi-channel seismic reflection data) acquired by Geological Survey of Canada in 1988 (left) to seismic reflection data acquired during late 1960's by Shell Canada (right). Although some of the apparent differences are due to the different plotting parameters used and could probably be improved by re-plotting the improved quality of the seismic data acquisition is obvious.

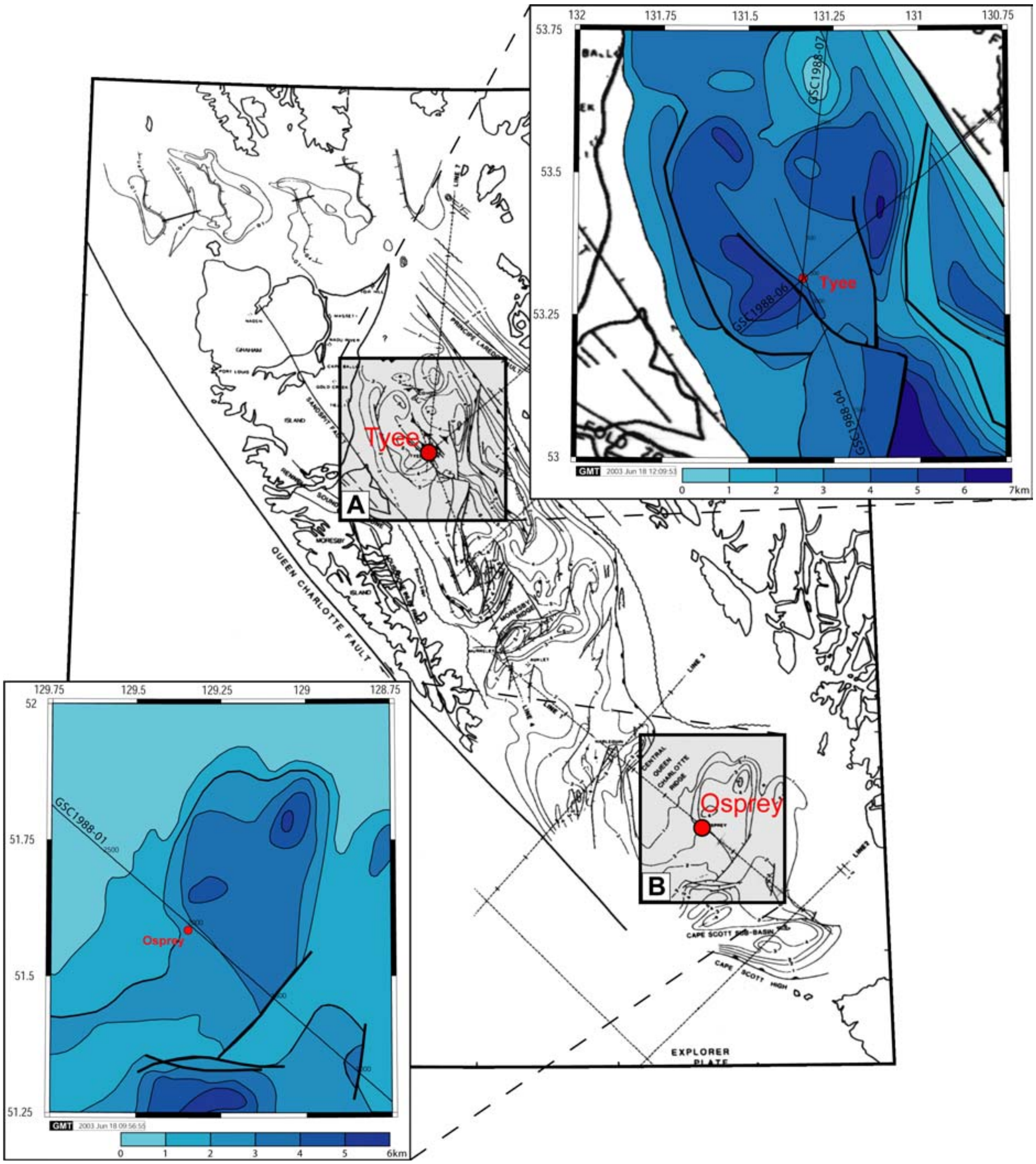

Figure 11. Detailed isopach map based on Rohr and Dietrich (1992). Most of the wells drilled offshore by Shell in late1960's did not penetrate areas with the greatest thickness of sediments. Fig 11a shows an enlarged plot of sediment thickness around the Tyee well in northern Hecate Strait, Figure 11b shows an enlarged plot of sediment thickness around the Osprey well in southern Queen Charlotte Sound.

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Nevertheless, the existence of an intricate network of faulted half-grabens and grabens throughout Hecate Strait and Queen Charlotte Sound and even east of Principe-Laredo High clearly showed the extensional nature of the basin (see Appendix A for pull out seismic lines 88-01 – 88-07, Figures A1 – A4). This result was contrary to previous ideas of basin formation (Yorath and Hyndman, 1983), which believed that rifting occurred primarily in Queen Charlotte Sound and that Hecate Strait was a Pliocene flexural basin. Evidence for ongoing extension in the Miocene can be found in many sub-basins. Small-scale extensional faults cut lower sections of the half-grabens and reflections diverge towards the basin-bounding fault indicating deposition during faulting. This pattern is observed mostly in the lower Miocene in the data in Queen Charlotte Sound (Figures A1 and A2a) and in both the lower and upper Miocene in Hecate Strait (Figures A2b – A4).

The general shape and location of sub-basins is described by an isopach map of Neogene basin fill (Figure 11). This map was constructed largely from seismic reflection data collected during the exploration phase of the late sixties and calibrated using the 1988 seismic reflection data set (Rohr and Dietrich, 1992). Interpretation of the earlier dataset is hampered by a long source signature because processing techniques of the time could not compress it (Figure 10). Distinguishing basal volcanic flows from basement is difficult in places because of their similar physical properties.

North to south variations in basin structures were used by Rohr and Dietrich (1992) to argue that distributed strike-slip motion was occurring during rifting and subsequent compression. Sub-basins in Queen Charlotte Sound generally trend north-south. Sub-basins in Hecate Strait trend northwesterly and are complicated by thrust faults and rejuvenation of normal faults into reverse faults (e.g., Figure 11). Sub-basins in Dixon Entrance form an en-echelon belt of northwest trending half-grabens with compression observed in their northern ends.

The cause of basin formation remains unknown. Hyndman and Hamilton (1993) correlated volcanism to a period of transtension on the Queen Charlotte Fault but Miocene extensional faulting occurred during an episode of compression according to the same relative plate motion model. Two new relative plate motion models (Norton, 1995; Atwater and Stock, 1998) agree that from 45-5 Ma the dominant motion between Pacific and North American pates at these latitudes was strike-slip with insignificant tension or compression. The transition from subduction to transform motion along the margin is probably indirectly related to basin formation but specifics are unknown (Rohr and Currie, 1997, Hamilton & Dostal, 2001).

Inversion of normal faults into reverse faults in Hecate Strait shows that the North American plate was internally deformed during the current episode of transpression on the Queen Charlotte Fault which began at ca. 5 Ma (Figure A2b, SP 1552-2250, T7, SP 1250-1450). This observation renders previous interpretations of tectonic interaction on the Queen Charlotte Fault (Hyndman and Ellis, 1983) questionable because they assumed that the North American plate had not deformed internally. Inversion only occurs inboard of the Queen Charlotte Islands and clearly involves basement. Uplift and compression are accommodated by positive flower structures, folds, thrust and reverse faults. It varies spatially and is episodic. The specifics of episodes of deformation cannot be determined until more detailed structural and timing data are available. A tectonic model, which includes compression to uplift the Islands and invert sub-basins while preserving the Queen Charlotte Fault as a major transform fault, was published by Rohr et al. (2000). The mechanics and deep structure of accommodation of compression on the Queen Charlotte Fault and in the Queen Charlotte Islands is debatable (Rohr et al., 2000; Mazzotti et al., 2003).

Lack of deformation in Queen Charlotte Sound brings current plate boundary models into question. Quite a variety of models have been published (e.g. Riddihough et al., 1980; Carbotte et al., 1989) but many posit transpression followed by subduction at the base of the continental slope. Widespread deformation in Hecate Strait shows how easily the Queen Charlotte Basin is deformed yet we see very little tectonic deformation in Queen Charlotte Sound in the Pliocene (Figure A1, A2a). Alternatively, adjustments to the change in relative motion at 5 Ma may have been entirely accommodated in the weak oceanic crust offshore (Rohr and Furlong, 1994).

4.3 Seismic – Stratigraphic Correlation

Stratigraphic ages from the well reports were correlated to the seismic reflection sections by synthetic seismograms (Dietrich, Pers. Comm.; 1989). Summaries of this stratigraphy have been published in Dietrich (1993) and with some modifications in Dietrich (1995) and Hannigan (2001).

The Miocene-Pliocene reflector was determined from 6 well penetrations and is fairly easily traced from line to line because it lies above the basement highs (Figures A1–A4). Deeper layers are more difficult to track away from the wells because of the geology itself. Stratigraphy interpreted for reflections at one well site can usually not be correlated into an adjoining sub-basin because a basement high intervenes (e.g., Figure A2a, SP 1900-2500). A number of vertical faults separate different sets of reflectors implying strike-slip motion on the fault but also impeding stratigraphic correlation (e.g., Figure A3b, SP 300-600). Lateral variability in amplitude and small unconformities within the sub-basins attest to lateral lithologic variation and local tectonic activity (e.g., Figure A3a, SP 750-1100). These observations render simplistic basin-wide correlations of lithology suspect.

Basaltic flows drilled in the Harlequin, Osprey, Auklet and Murrelet wells show up in the seismic reflection data as high amplitude sub-parallel reflections at the base of the sediments. In these sub-basins basement was usually taken to be the base of these events. Basalt flows at the base of the sedimentary sections interfinger with sediments and do not necessarily spread across the entire sub-basin (e.g., Figure A1, SP 32125). They can mask reflections from pre-existing stratigraphy (Figure A3a, SP 850-1000); alternatively layering within Cretaceous sediments could easily be mistaken for volcanic flows (e.g.,

Figure A3b, SP 450-550). In practice volcanic rocks and basement can be difficult to distinguish because of their similar physical properties.

5. Stratigraphy

In the well reports ages were assigned to strata based on identifications of pollen and microfossils in the well samples. The Murrelet, Harlequin and Osprey wells have been reexamined for micropaleontologic evidence. In spite of sparse fauna and few recovered specimens Patterson (1989) identified early-mid Miocene shelf foraminifera in the Murrelet, and Harlequin wells and a slope fauna in the Osprey well. A non-specific fauna, which lived in the Pliocene to Quaternary, was identified in the upper sections of all three wells. He also noted that ca. 1700 m of section in the Murrelet well was barren of foraminifera. Pollen from the Harlequin well (White et al., 1994) indicate that the Miocene-Pliocene boundary occurs at 500 m depth whereas the palynological study for the Harlequin well (1969) suggested that it was at ca. 1030 m. and the paleontological report (1969) indicates that it was between 679 and 960 m. Similar discrepancies occur in the Osprey well.

Higgs (1991) correlated the wells on the basis of sonic log characteristics and assigned strata to post- or syn-rift units. The end of rifting and formation of post-rift regional correlative blankets of sediments varies from (Dietrich, 1995) mid-Miocene to late Miocene in the basin. As discussed above significant vertical and lateral facies changes and local unconformities make it very difficult to reliably assign ages to rocks based on lithologic character alone.

Regional variations in lithology in the wells were observed but are hard to place too much importance on given the sparse sampling of the Basin. Basaltic flows were drilled in the southern wells (Osprey, Harlequin, Auklet and Murrelet) and appear as thin layers in the Sockeye B-10, Coho and Tyee wells, but interpretations of the seismic reflection data suggest that syn-extensional basalts were present in other sub-basins in Hecate Strait (Figure 12).

Presence of bentonites in the southern wells indicates that aerial dispersal of volcanic material was ongoing. Coals are ubiquitous in the lower half of wells. Facies are more vertically variable in syn-rifting units than post-rift. In the seismic data the post-rift sequence appears as sub-parallel reflections that extend for kilometres. Uplift of strata and basement highs inhibit correlation in many places.

Data and reports from the eight wells drilled offshore by Shell Canada Ltd. were reviewed (Table 3)(Figures 2 and 12). Strata units and sequences for each well were interpreted from the original Shell Canada lithological report on the cuttings and well log gamma ray, sonic, spontaneous potential, resistivity, bulk density, and conductivity data. Microflora and fauna intervals indicated (Figure 2) are from the original reports ; they need to be updated to current paleontological zones and standards.

A lithologic well correlation from approximately north to south (Figure 2) provides some strata linkages in the Miocene and is a different interpretation than that by Shouldice (1971), Patterson (1988), and Higgs (1989). Of particular interests are:

1. interbedded layers and an abundance of coals;
2. hydrocarbon shows in the Sockeye B-10 well;
3. the presence of glauconite, calcite and pyrite that may indicate marine conditions;
4. bentonites and volcanics; and
5. fining-up sequences indicating deeper water depths or subsidence.

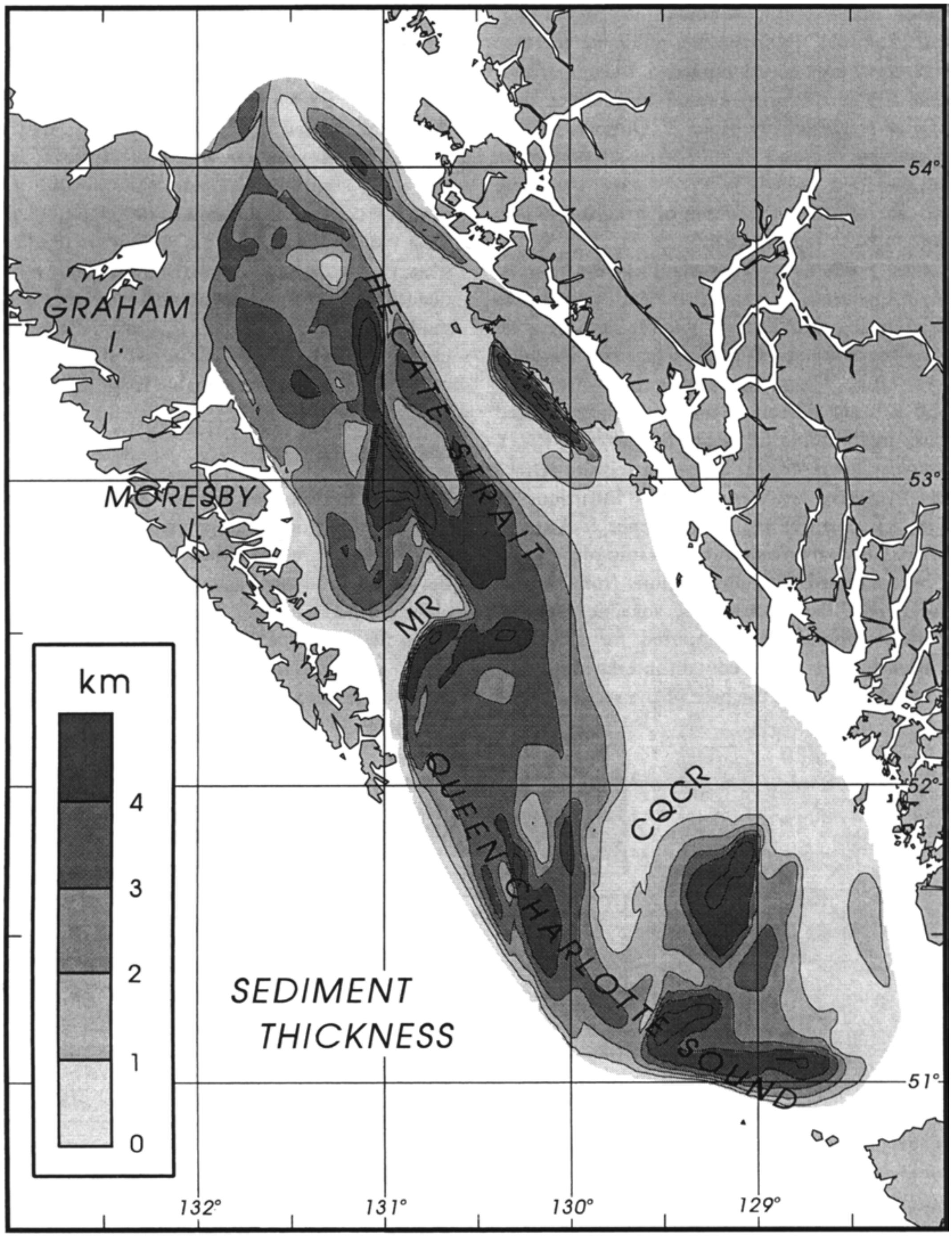

Figure 12. Sediment thickness in Hecate Strait and Queen Charlotte Sound, as presented by Dehler et al. (1997). The Central Queen Charlotte Ridge, Moresby Ridge, and Principe Laredo High have prominent crustal horst-like features and show very thin sediment cover. Important for the hydrocarbon assessment are maxima in sediment thickness, located in the south western Queen Charlotte Sound and southern Hecate Strait.

6. Geochemistry

The initial source rock geochemistry characterization for the QCB has been derived from samples of the 8 offshore wells in Hecate Strait, as well as from selected outcrops on the QCI (Macauley, 1983 and Snowdon et al., 2002). Most of the geochemical assessment work has been previously reported by other investigators including Bustin & Mastalerz (1995), Dietrich (1995), Hamilton & Cameron (1989), Fowler et al. (1988), Snowdon et al. (1988), and Vellutini and Bustin (1991). A review of this work is presented in Section 3.3.

Three basic geochemical parameters are used to judge the formation potential of source rocks in the QCB (*see also* Section 8.1):

1. Amount of organic material: Total Organic Carbon (%TOC)
2. Type of organic material: Kerogen Type (Type I, II or III)
3. Maturity of organic material: Vitrinite Reflectance (%Ro)

6.1. Amount of Organic Material

There are units in the QCB with adequate amounts of organic matter to form hydrocarbons (see Section 3.3). Although the type of kerogen in the source rock is important when considering proneness for oil or gas formation, the amount of organic matter present is critical if sufficient generation will occur to make economic accumulations of petroleum, provided migration, trapping and preservation criteria are also met.

Based on studies of outcrops on the QCI the Kunga and Maude groups are the most prospective sedimentary formations in the region. They are Latest Triassic and Early Jurassic organic-rich marine mud rocks which reach up to 600 m in thickness. Measurements on samples report TOC up to 6.1% and as high as 10% TOC in some cases (Dietrich, 1995).

In younger units of Cenozoic age TOC values up to 30% have been reported (Bustin, 1997), however, the organic rich beds only contain an average of approximately 1.25% TOC. Although marine units are present, terrestrial, humic (coaly) source rocks have been drilled.

The %TOC in the sedimentary successions of the eight offshore wells in the QCB is highly variable (Figure 13), with values ranging from almost 0% to over 60%. The highest TOC values found are in the Sockeye B-10 well (ca. 60%), in the South Coho well (ca. 50%), in the Sockeye E-66 well (ca. 40%) and in the Tyee well (ca. 40%), whereas the Auklet well (ca. 12%), the Murrelet well (ca. 10%) and the Harlequin, as well as the Osprey wells (less than ca. 5%) show significantly smaller maximum values for TOC (Bustin, 1997).

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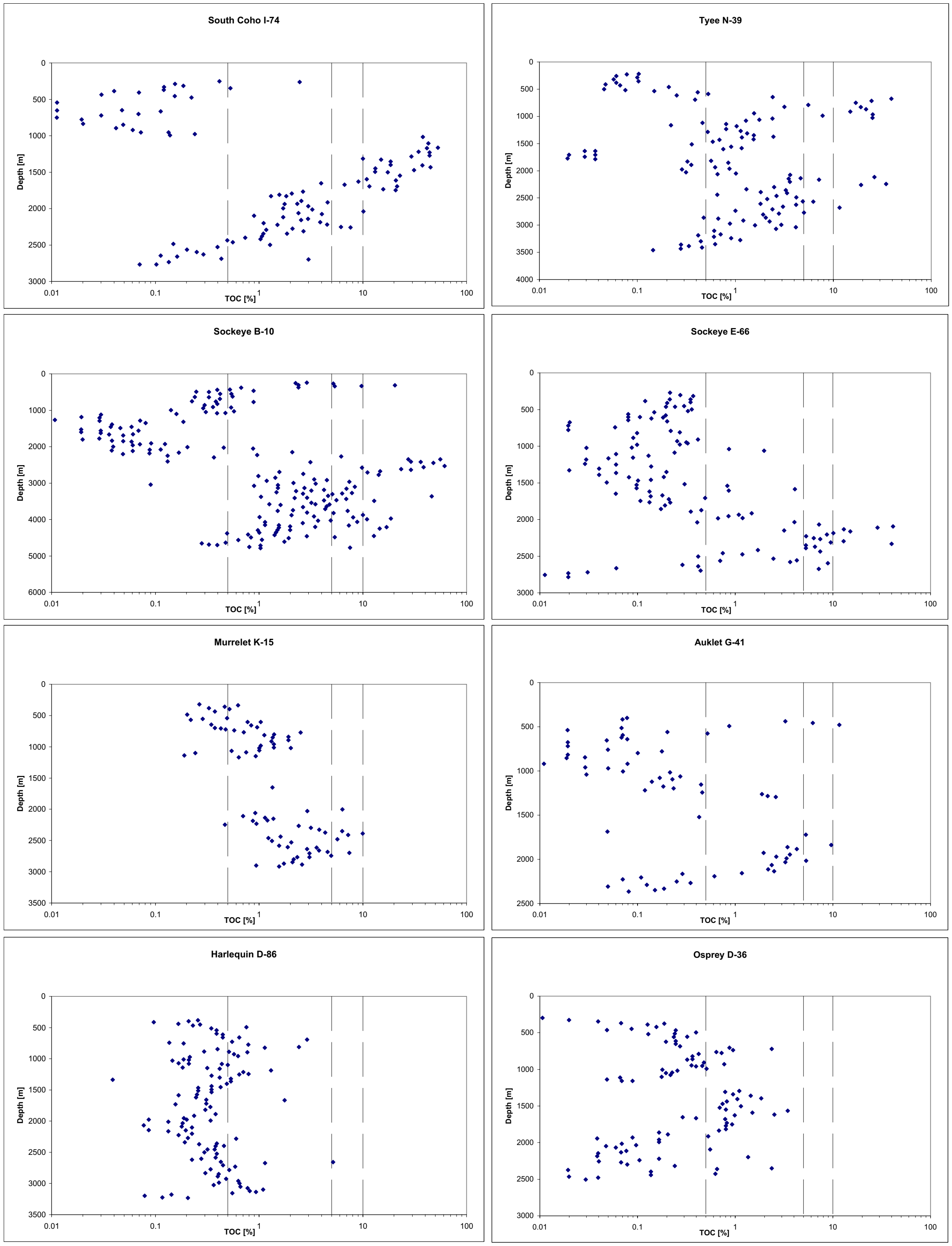

Figure 13. Depth distribution of Total Organic Carbon (%TOC) for the 8 offshore QCB wells (after Bustin 1997).

The TOC's for the South Coho, Tyee, Sockeye B-10 and E-66, Auklet and Osprey show a characteristic trend with depth (Figure 13). The TOC begins with values below 0.5% at the base of the drilled sedimentary successions and increases with decreasing depth to higher values followed by a decrease of the TOC down to values of less than 1%. In the uppermost part of the sedimentary successions of the South Coho, Tyee, Sockeye B-10, Auklet and Osprey wells the values for TOC increases again considerably, whereas the Sockeye E-66 well only shows a slight increase in TOC. In the Tyee and in the Osprey wells this increase is followed again by decreasing TOC values. The distribution of TOC versus depth in the Murrelet K-15 and the Harlequin wells shows no distinct pattern.

The values for TOC and their distribution with depth for the wells (Figure 13) indicate the presence of very good source rocks (TOC > 10%), good source rocks (TOC between 5 and 10%) and moderate source rocks (TOC between 0.5 and 5%; Tissot and Welte, 1978), with good to very good source rocks are most likely present in the northern part of the QCB (South Coho, Tyee, Sockeye B-10 and E-66) and moderate to good source rocks in the southern part of the basin (Murrelet K-15, Auklet, Harlequin, Osprey).

6.2. Type of Organic Material

The compositional quality of the organic matter is critical to determine the type of petroleum formed, e.g., oil vs. gas. The proportion of hydrogen in the kerogen is an excellent measure of this proneness. Hydrogen-rich kerogen (Type I or II), as found in aqueous source rocks, forms oil more abundantly than low hydrogen or oxygen rich kerogens (Type III). The hydrogen index is frequently used to quantify the relative amount of hydrogen in the organic matter, and hence determine the kerogen type.

Detailed logs with lithologic descriptions were available through well reports from the eight Shell Anglo offshore wells (see Figure 2 for well locations). Utilizing van Krevelen and Rock-Eval S2 vs. TOC data, other investigators (see Figure 15, Bustin, 1997) classified most of the organic material in the 8 wells as Type III, with some kerogen of Type I/II in the Sockeye wells. The geochemical measurements by Bustin (1997) (Figures 14 and 15) have all been made on cutting samples and therefore bear a certain amount of uncertainty.

Overall the HI in the QCB wells is relatively low (Figure 14), with average values <200 mg HC/g C_{org} (Bustin, 1997). Modified van Krevelen diagrams (Figure 15) with oxygen index (OI) versus HI identify the present kerogen types mainly as humic Type III kerogen (HI < 300 mg HC/g TOC; Tissot and Welte, 1978). The only exceptions are the Sockeye B-10 wells (Figure 14 & 15) which have hydrogen-rich organic matter and therefore higher HI's (Bustin, 1997), indicating a sapropelic Type II kerogen (HI between 300 and 600 mg HC/g TOC; Tissot and Welte, 1978). These hydrogen-poor, Type II kerogens in the Cenozoic have limited oil proneness. If they generate hydrocarbons, they will tend to be dry natural gases, i.e., dominantly methane.

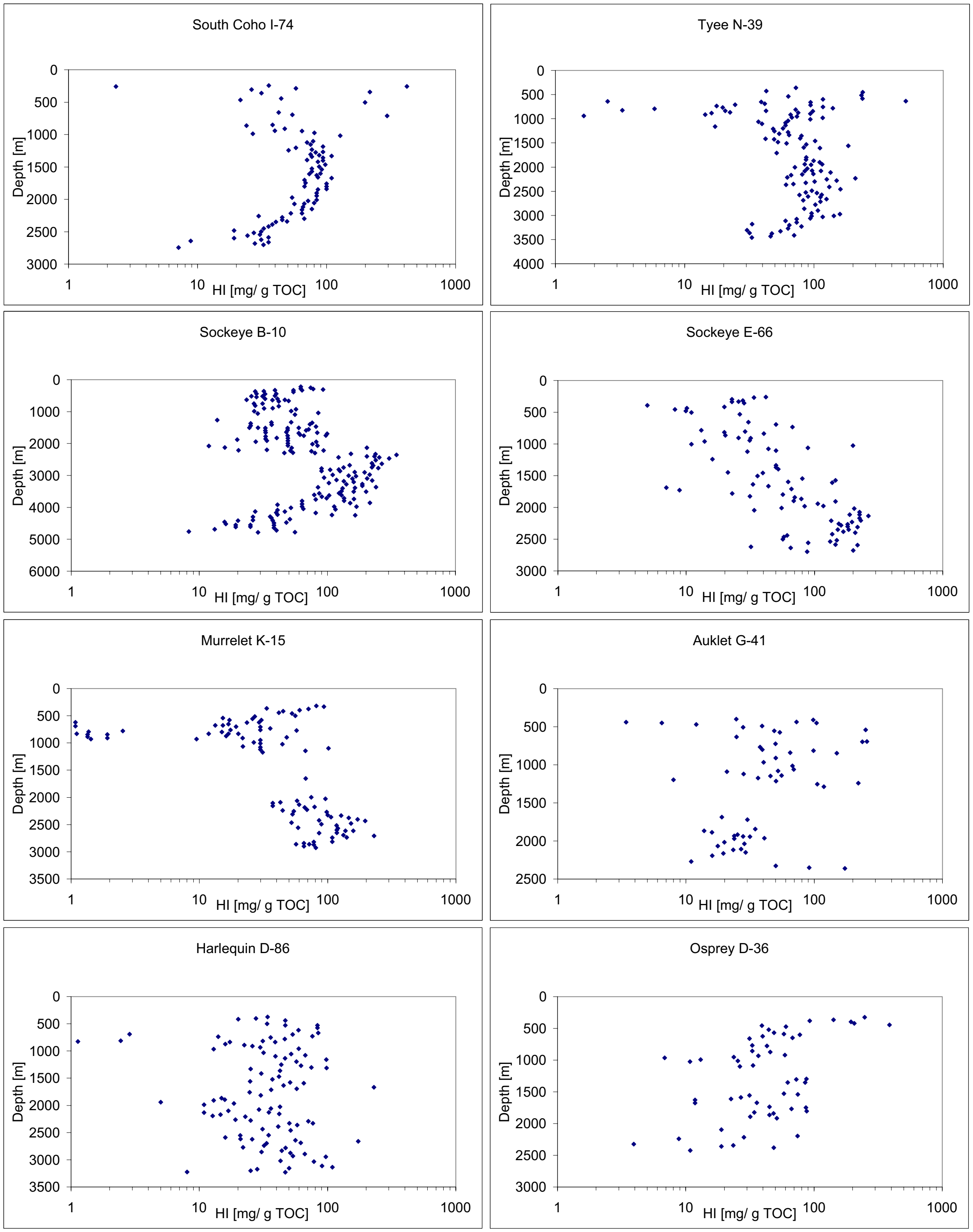

Figure 14. Depth plots of Hydrogen Index (HI) of the 8 offshore QCB wells (data from Bustin 1997).

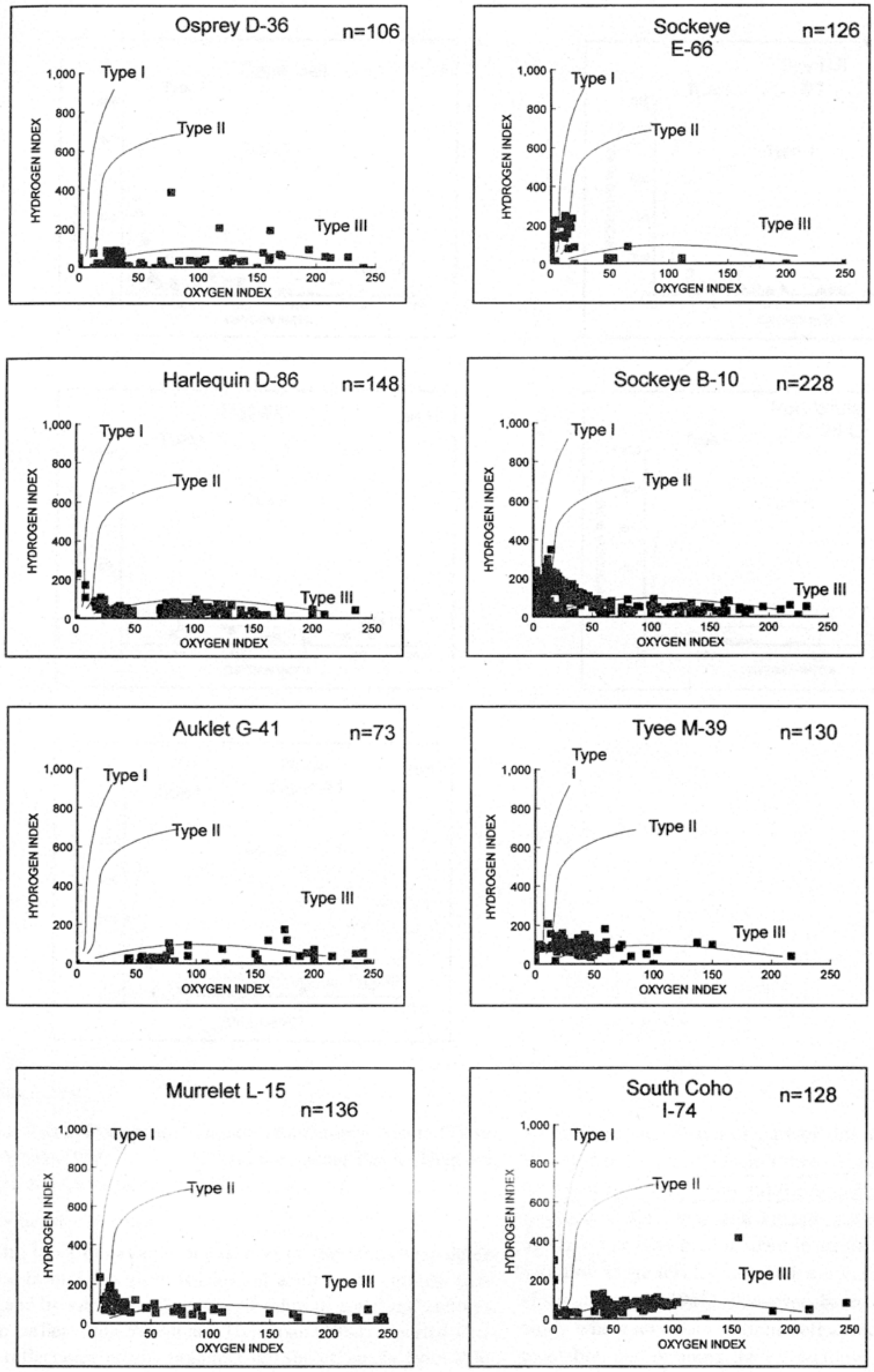

Figure 15. Source Rock quality plots of Hydrogen Index vs. Oxygen Index (modified van Krevelen) of the 8 offshore QCB wells (after Bustin 1997). Most of the Cenozoic source rocks offshore measured have a dominant Type III or humic character, with the exception of the Sockeye wells.

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The Tertiary drilled in the eight QCB offshore wells is dominated by Type III kerogen with few exceptions encountered in the depth interval between approximately 2,000 and 3,000m in both Sockeye wells generally reflecting pre-Middle Miocene strata, including inferred Cretaceous sediments in the Sockeye E-66 well (Figures 14 and 15). The reported HI reaches a maximum of approximately 370 mg HC/g TOC in one sample from the Sockeye B-10 well, but generally remained below 250 mg HC/g TOC.

It is important to note that the offshore wells are largely limited in depth to Tertiary units. It is anticipated that deeper in the basin there are Mesozoic (Jurassic) units that have oil and gas prone Type II kerogens. Indirect evidence for this comes from

1. Latest Triassic and Early Jurassic marine mud rocks of the Sandilands and Ghost Creek formations from the Kunga and Maude groups are found on the Queen Charlotte Islands. The Sandilands Formation is likely to occur in most parts of the Wrangell Terrane, underlying Hecate Strait and Queen Charlotte Sound (Cameron & Tipper, 1985, Woodsworth, 1988, Thompson et al., 1991)

2. Both Sandilands and Ghost Creek formations have high %TOC and have evidence of Type I and II kerogens with HI values ranging up to 589 mg HC/g C_{org} (Bustin & Mastalerz, 1995, Dietrich, 1995).

3. Onshore oil shows have chemical compositions that appear related to a Lower Jurassic source (Fowler et al., 1988, Snowdon et al., 1988, Hamilton and Cameron, 1989, Bustin and Mastalerz, 1995).

It has to be stated here that although the wells mainly encountered Type III kerogen hydrogen rich Type I/ II kerogen have been reported from samples of Mesozoic rocks on the QCI (Figure 16). The data published for the source rock intervals reported from the QCI (Macauley, 1983 and Snowdon et al., 2002) reveal the different nature of these Mesozoic source rocks. They generally show HI values in the range of 200 to 600, which clearly places them on typical trends for Type I/II kerogen.

Of further interest is that most of the onshore samples show RockEval Tmax values that place these kerogens in the oil window, (Snowdon et al., 2002; Figure 17). This maturation equivalent uses the correlation of Tmax to maturation level for individual types of kerogen (Espitalié, 1986). Figure 17 clearly shows that most of the samples from the Mesozoic Kunga and Maude groups on the QCI are in the oil window today.

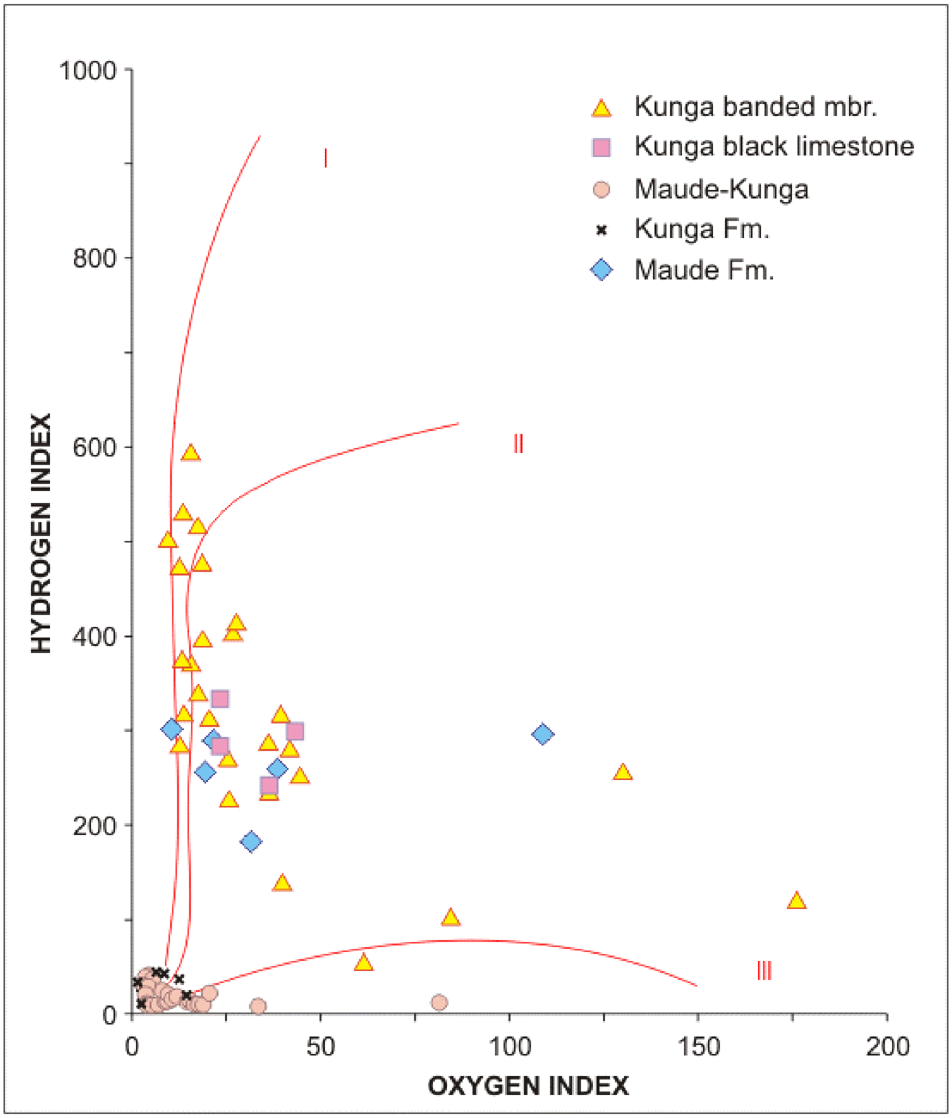

Figure 16. Published data for the source rock intervals reported from the Queen Charlotte Islands (Macauley, 1983 and Snowdon et al., 2002) reveal that the Mesozoic Kunga and Maude source rocks contain marine, Type II-dominated kerogens.

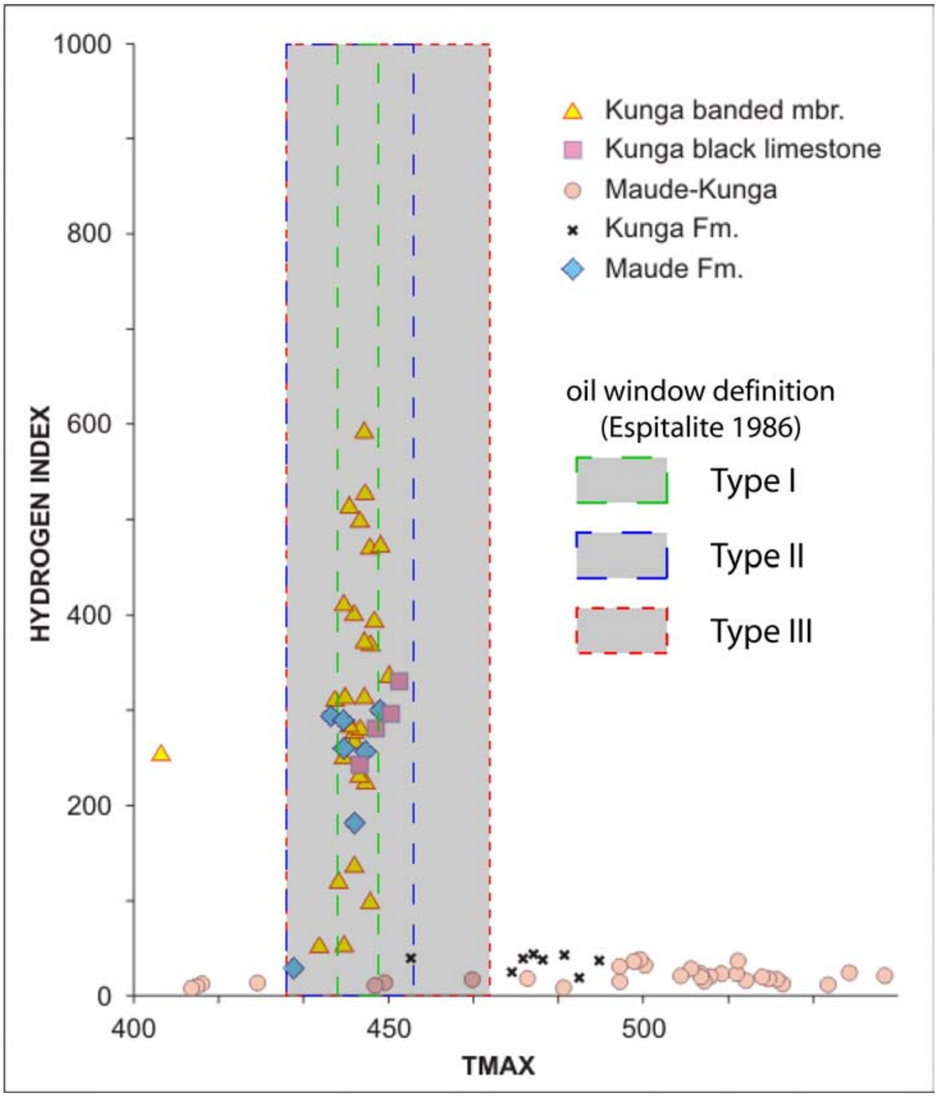

Figure 17. HI vs. Tmax plot for Queen Charlotte Islands (QCI) outcrop samples (modified after Snowdon et al., 2002). Based on the correlation of Tmax to maturation level for individual types of kerogen (Espitalié, 1986), this plot indicates that most of the samples from the Kunga and Maude groups are in the oil window.

6.3. Maturity of Organic Material

Potential source rocks in the offshore QCB wells have reached sufficient maturity in several regions of the basin. This is based primarily on direct vitrinite reflectance measurements (VR recorded as %Ro) made on cuttings samples from the 8 offshore wells. This has been augmented by our basin modeling which combines stratigraphic and age information and has been calibrated to measured %Ro values.

Table 7 below shows the generalized depth intervals for the 6 major maturity zones in the QCB today:

a) Immature – no generation expected
b) Marginally Mature – very limited and special generation, i.e., resinites
c) Mature oil – generation of oil if appropriate source rocks present
d) Mature oil + gas – generation of oil and gas if appropriate source rocks present
e) Late mature – predominantly dry gas (methane) or condensate
f) Overmature – overcooked source rocks, no generative potential left today

There are local differences, which are discussed in more detail in Section 7.2.

Today the source rocks of the QCB Cenozoic package cover the spectrum of Immature to Late Mature over the depth range of surface to 4,800 m. At greater depths, any offshore source rocks are expected to be overmature today, but they have not been drilled.

Table7. Generalized source rock maturity zones of the QCB as vitrinite reflectance equivalent (VR).

Maturity Zone	VR range (% Ro)	Minimum Depth (m)	Maximum Depth (m)
Immature	< 0.3	0	< 1,200
Marginally Mature	0.3 – 0.5	1,200	2,100
Mature (oil)	0.5 – 0.8	2,100	2,800
Mature (oil + gas)	0.8 – 1.2	2,800	4,100
Late mature (gas)	1.2 – 2.0	4,100	4,800
Overmature	> 2.0	>4,800	

Notes: 1) Due to insufficient coverage, these maturity depths are calibrated for the Tertiary units only. Mesozoic sequences probably display different maturation profiles, but this has not been measured offshore.
2) These values are generally valid only for oil prone Type II kerogens. Humic Type III kerogens show different kinetic behavior.

All of the above maturity conditions are likely to be present in the QCB today. The estimation of the maturity depth zonation in the geologic past, especially the pre-

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Cenozoic era, is more difficult, due to uncertainties in the heat flow history and source rock characteristics, as is discussed in Section 8.2.

Figure 18 shows cross-plots of vitrinite reflectance (%Ro) versus depth for the different QCB offshore wells (data from Bustin, 1997). The stippled vertical lines in the diagrams represent the start of the oil window (VR of 0.5 %Ro), and the start of the gas window (1.2%Ro) using the classification by Wright (1980).

The %Ro values for South Coho, from the shallow parts of the sedimentary succession down to the total depth (TD) at 2781m, are below a VR of 0.7%Ro. This indicates marginally mature conditions. The VR values for the upper ca. 2000 m of Tyee well are also immature whereas the lower part of its sedimentary succession from ca. 2000 m to 3,461 m (TD), is in the oil window (VR > 0.5%Ro). Sockeye B-10 has VR values between 0.5 and 1.2%Ro in the depth interval from ca. 2,000 m to 4,500m, indicating oil window conditions. From ca. 4,500 m to TD (4774m) the VR values are greater than 1.2%Ro, i.e., in the gas window. It should be considered in this context, that the Sockeye B-10 well is by far the deepest offshore well in the QCB. The VR values for Sockeye E-66 are in the oil window between ca. 1,700 m and TD (2,787 m). The upper 2,000 m of the Harlequin well are immature (VR < 0.5%Ro). The interval from 2,000 m down to TD (3,242 m) has VR values slightly above 0.5%Ro, suggesting the beginning of the oil window. Murrelet K-15, Auklet and Osprey wells have only a few VR measurements made on them. This restricts the interpretation of maturity trends in these wells. However, the deepest intervals of all three wells have VR values indicating a mature zone, i.e., oil window (Figure 19).

Our modeling demonstrates that the maturation depth profiles of the Cenozoic units are relatively uniform across the basin, i.e., at any particular depth, the maturity will be approximately the same for different locations in the QCB (Figure 20). This reflects the recent uniform and consistent subsidence and heating history for the offshore region over most of the Cenozoic.

The QCB Cenozoic package typically enters the top of the petroleum window today at or just deeper than 2,100 m (0.5 %Ro, Type II, Figures 19 and 20). Restricted, if any, production will result in the shallower Marginally Mature zone (1,200 to 2,100 m). The oil window (Mature, oil) today extends to depths of approximately 2,800 m (0.8 %Ro, Type II), while the Mature oil + gas window currently brackets 2,800 to 4,100 m. The bottom of this zone is deeper than most of the wells drilled in the QCB. Most of the offshore QCB wells encountered Cenozoic sediments which have a maturity of less than 0.8 %Ro, i.e., are in the formation stage of early petroleum window or younger. The Sockeye B-10 well is an exception in that at TD (4,773 m) the measured maturity of the sediments is ca. 2 %Ro.

Based on the measured %Ro profiles for the wells, the Late Mature (gas window) in the QCB today is between 4,100 m and 4,800 m (1.2 – 2.0 %Ro, Type II). Only the Sockeye B-10 approaches the base of the gas generation zone, (Figure 19).

Any sedimentary units currently deeper than 4,800 m are likely overmature and have little, if any, generative potential.

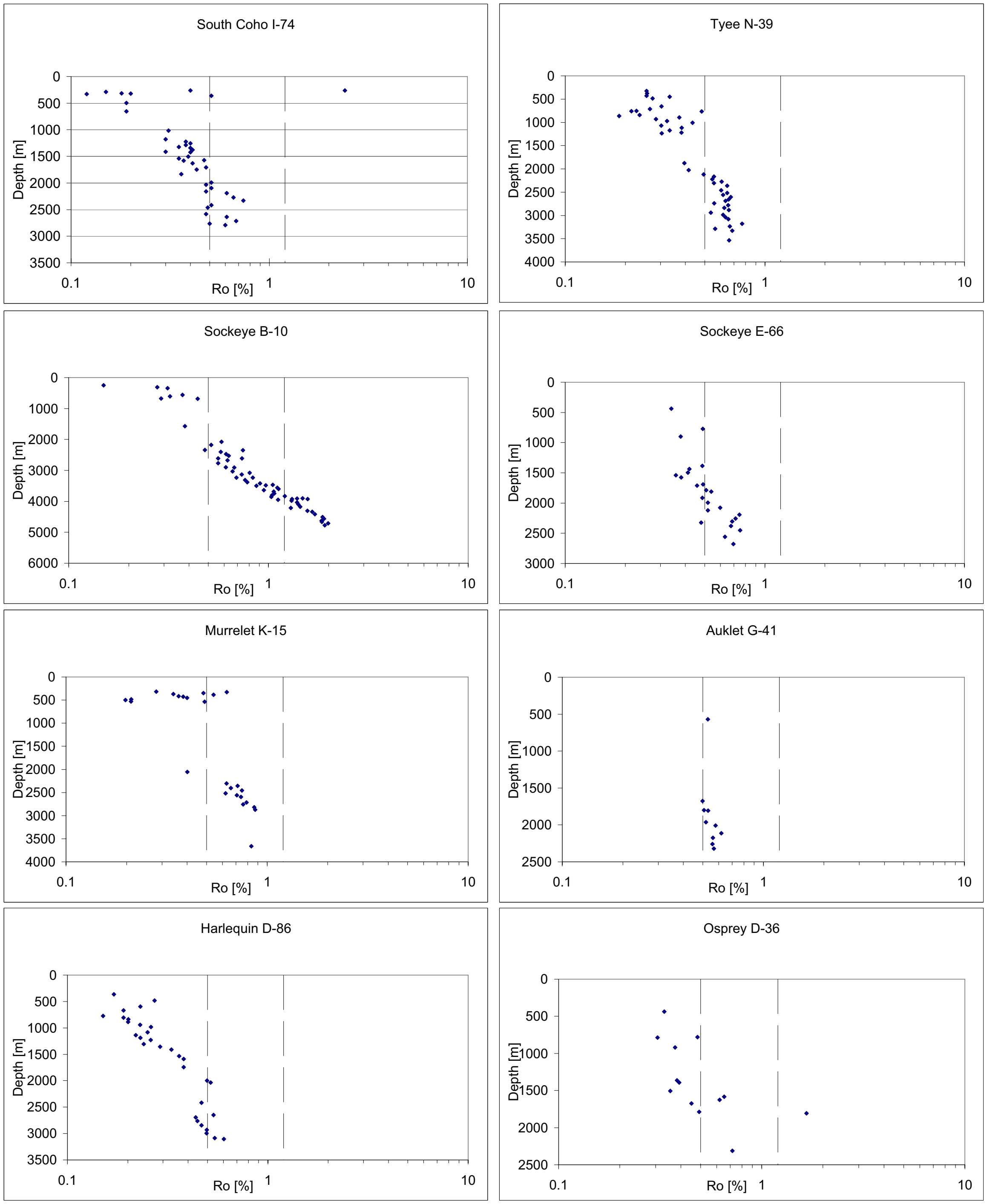

Figure 18. Depth plots of Vitrinite Reflectance of 8 offshore QCB wells (data from Bustin 1997). Lines are drawn at 0.5%Ro (top mature zone, oil window) and 1.2%Ro (base oil window and top gas window) for reference.

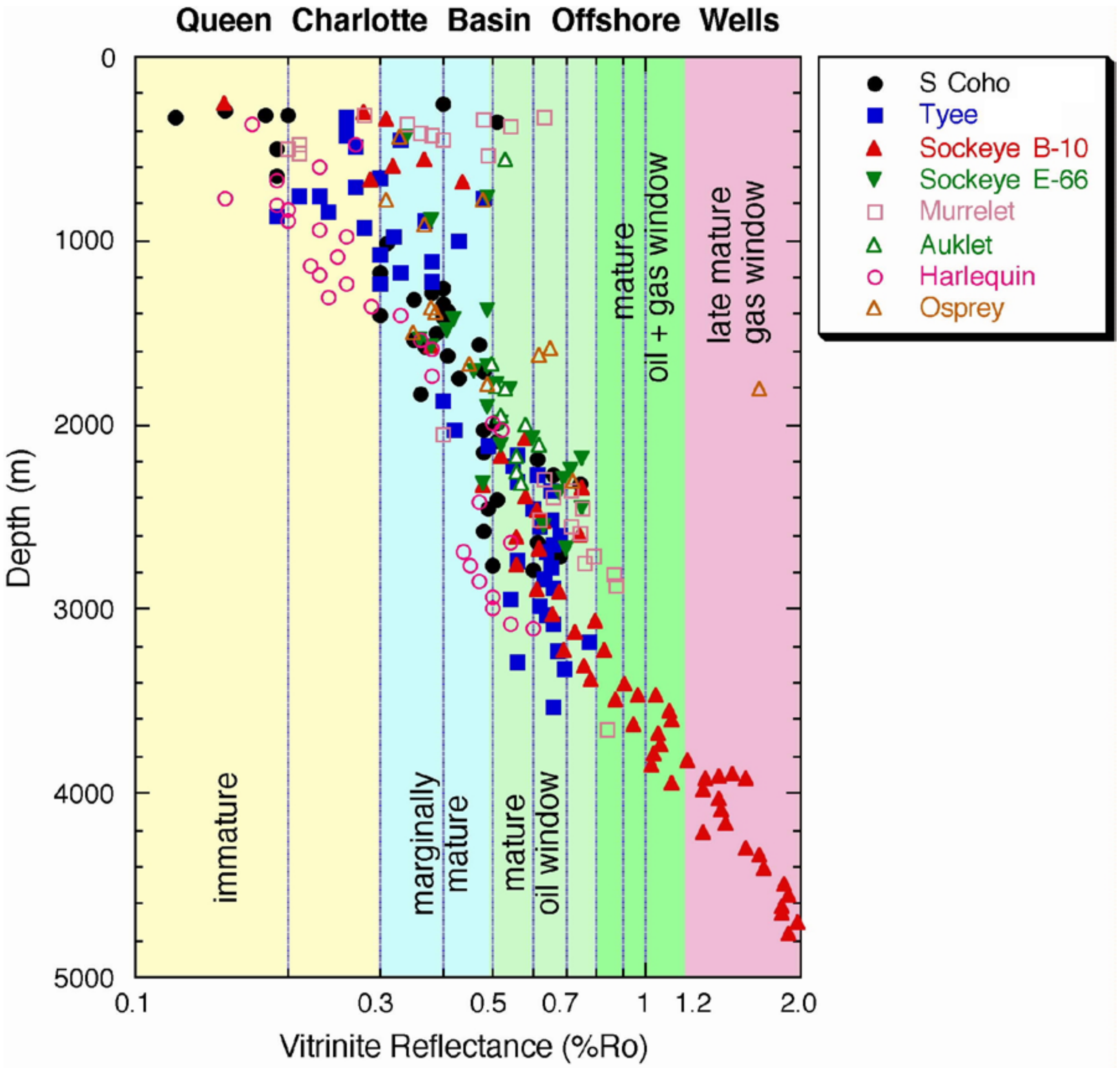

Figure 19. Combined depth plots of Vitrinite Reflectance (VR) of 8 offshore QCB wells showing maturation zones (data from Bustin 1997).

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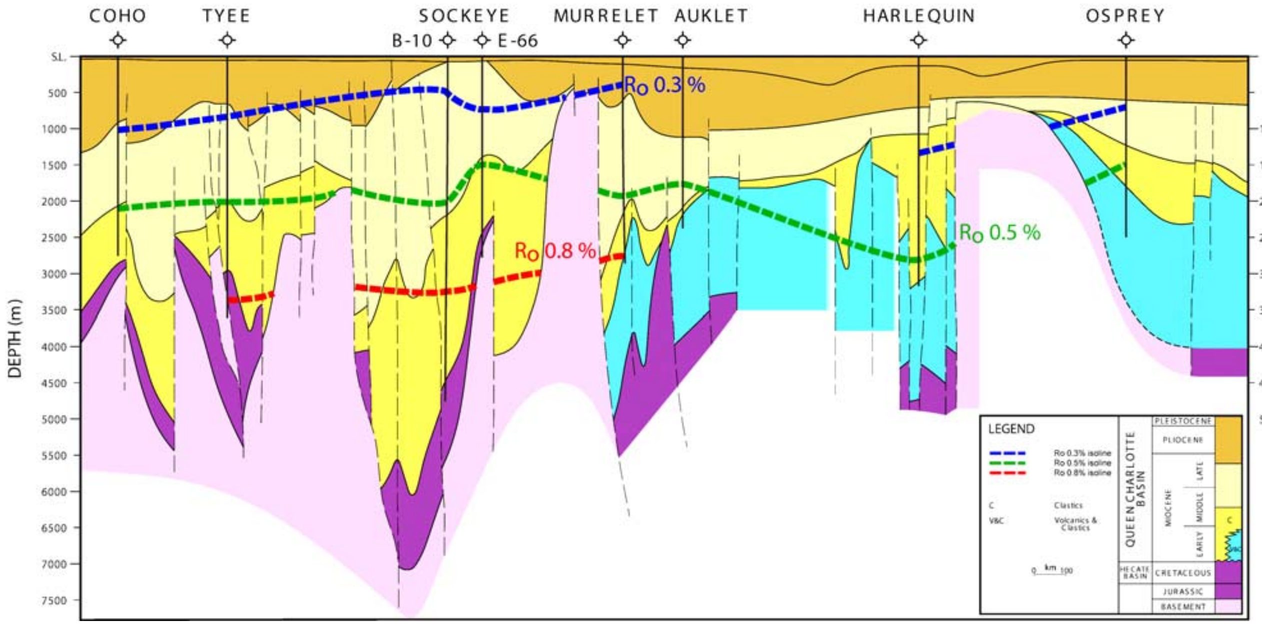

Figure. 20. Schematic representation of present structural-stratigraphic cross section (NW – SW) connecting 8 offshore QCB wells (Dietrich, unpublished data); coloured stippled lines indicate isolines for vitrinite reflectance values (Ro) 0.3%, 0.5%, 0.8%; data derived from Bustin (1997).

7. Basin Modeling

It should be noted that the software packages to be used in the study (IES PetroMod (IES), IFP Temis 2D (Beicip-Franlab), Claritas (GNS), and IESX (Schlumberger)) are full commercial products, with a combined normal purchase price of over $500,000, excluding any hardware or operational expenses. Through our deep educational discount, we are able to implement these geophysical and petroleum system modeling software packages for use in this study. It is understood that the work conducted here is of a purely academic research nature and is not for commercial gain.

7.1 1-D models

Wells drilled in the late 1960's, as well as the reflection seismic shot in 1988, did not sample the deepest parts of the sub-basins. The 1D basin models presented here are all based on well log information from the offshore Shell Anglo wells and therefore do not necessarily reflect the scenarios of maximum burial and maturation. It can reasonably be assumed that higher maturation levels than modeled would have been achieved within these zones of depositional maximum.

As 1D models can be constructed much faster, consume less computing time, and offer a more direct method to calibrate important parameters than 2D models, the first scenarios investigated and presented as result of phase I in this report are 1D models. Necessaorily, they are restricted to the Shell Anglo well locations and reflect their geological evolution through time (see Figure 2 for well location). The burial and maturation history of the eight wells, located in the QCB were studied in further detail, using the PetroMod 1D software, provided by IES, Germany**.**

Most of the offshore well locations were intersected by the 1988 seismic reflection lines, as shown in Figure 9. For the 1D models presented here, the main seismic reflectors defined on the 1988 seismic reflection data and the seismic pattern, observed between these major unconformities (Figures A1 – A4), are used to estimate the paleo-morphology. This is an important parameter for the reconstruction of the burial history (see also Section 3.4).

The pre-Mesozoic evolution is of minor interest with respect to hydrocarbon generation in the QCB. Therefore it is not included within the models presented here. Although the Mesozoic, especially the Late Triassic/ Early Jurassic sediments, is known to comprise important marine source rock intervals, these preliminary models focus on the Cenozoic succession. This is partly due to the amount of information available. Only the Cenozoic portion of the QCB sedimentary column has enough resolution in the available seismic data to be used to build the models (Figures A1 – A4). The Mesozoic record has long time-spans (up to several tens of million years) between the defined thermal events, and no offshore well control. However, to allow a rough estimate of potential generation, the models incorporate most of the Mesozoic sediments. These are defined in much less detail in this Phase I of the project.

7.2 Stratigraphy and burial history

The stratigraphic concept used for the backstripping in this study is based mainly upon the work by Rohr and Dietrich (1992). This was also used as a base for the interpretation of the seismic reflection data (Figures A1 – A4). For the purpose of modeling, additional time-steps were introduced between the dated unconformities and sequence boundaries to ensure a more continuous evolution of the calculated model. Based on the available well log descriptions and seismic data, these additional lithologically derived sequence boundaries were dated, using an integrated interpolating approach, accounting for the overall sedimentary evolution and subsidence of the individual locations. It has to be stated here, that our seismostratigraphic concept is still very basic and needs major improvements in the future, e.g., dating of well samples. This simple approach to the stratigraphy is evident in Figures 21 to 28, which show the burial history during the last 45 Ma with an overlay of the modelled hydrocarbon zones (see text below for further explanation).

Further stratigraphic information is necessary to reasonably define additional marker horizons to construct models. Once such information is available, a more detailed burial history, defining smaller time-spans of more rapid subsidence and, or periods of uplift, could be incorporated into the models.

The first result of the 1D modelling is the calculation of tectonic subsidence and sedimentation rates for each of the 8 offshore wells. The calculation is based on the stratigraphic input parameters derived from the available logs or log descriptions.

Figures 21- 28 are subsidence history plots (depth vs. age) and hydrocarbon generation zones for all wells with results from the two models: “Cold” (top panel) and “Hot” (lower panel) using Type II kerogens (left panel) and Type III kerogens (right panel). The blue stippled line in combination with the gray shading marks the beginning of rifting, which becomes obvious by the augmented subsidence rates. The inferred differences in the timing of rifting could be related to individual rifting and subsidence processes in separate sub-basins, but at this early stage of the project they are more likely artifacts due to unreliable age assignments of individual marker horizons in the wells. Each well is located several tens of km apart in completely independent, separate sub-basins. The colours refer to modeled hydrocarbon maturation zones (blue: immature, green: oil-window, red: gas-window, yellow: overmature) and the vertical lines in corresponding colours project the start of the latter three zones onto the horizontal time axis at the top of the diagrams. Stippled lines in the upper panel refer to projections of the lower panel onto the time axis. Figure 21 has the maturity legend (colours) for all Figures 21 -28.

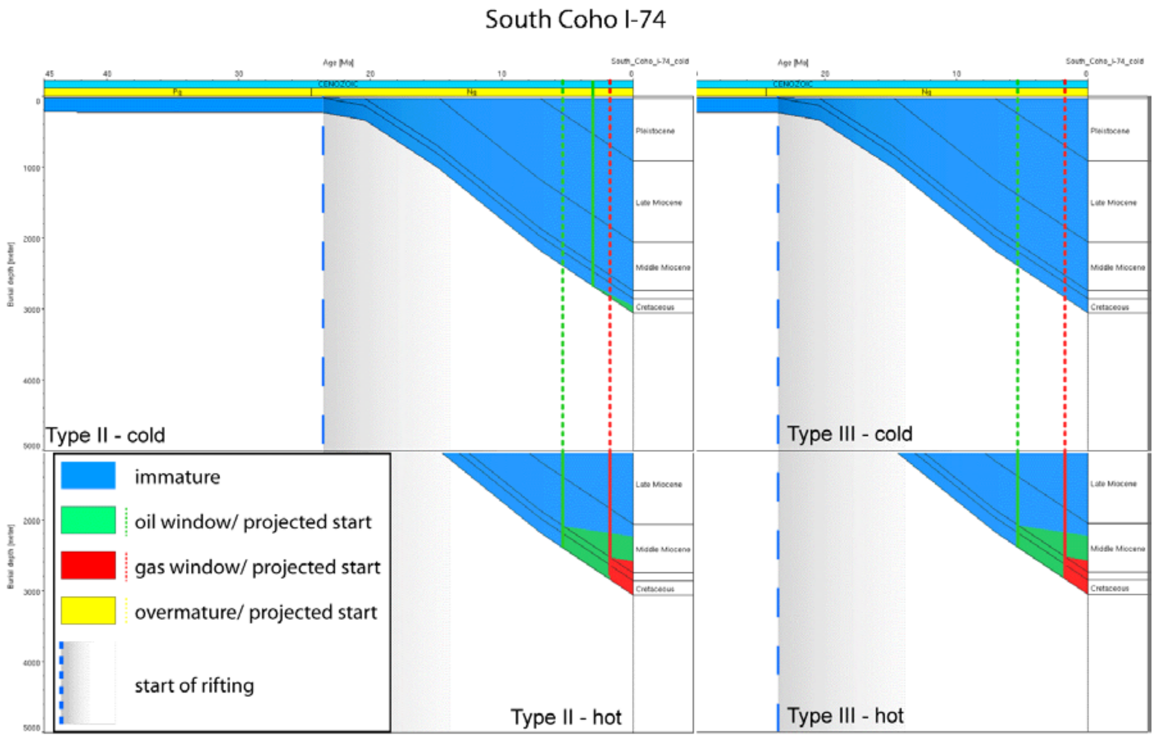

Figure 21. Burial and subsidence history of the South Coho well with an overlay of the modelled hydrocarbon zones (see text for a more detailed description).

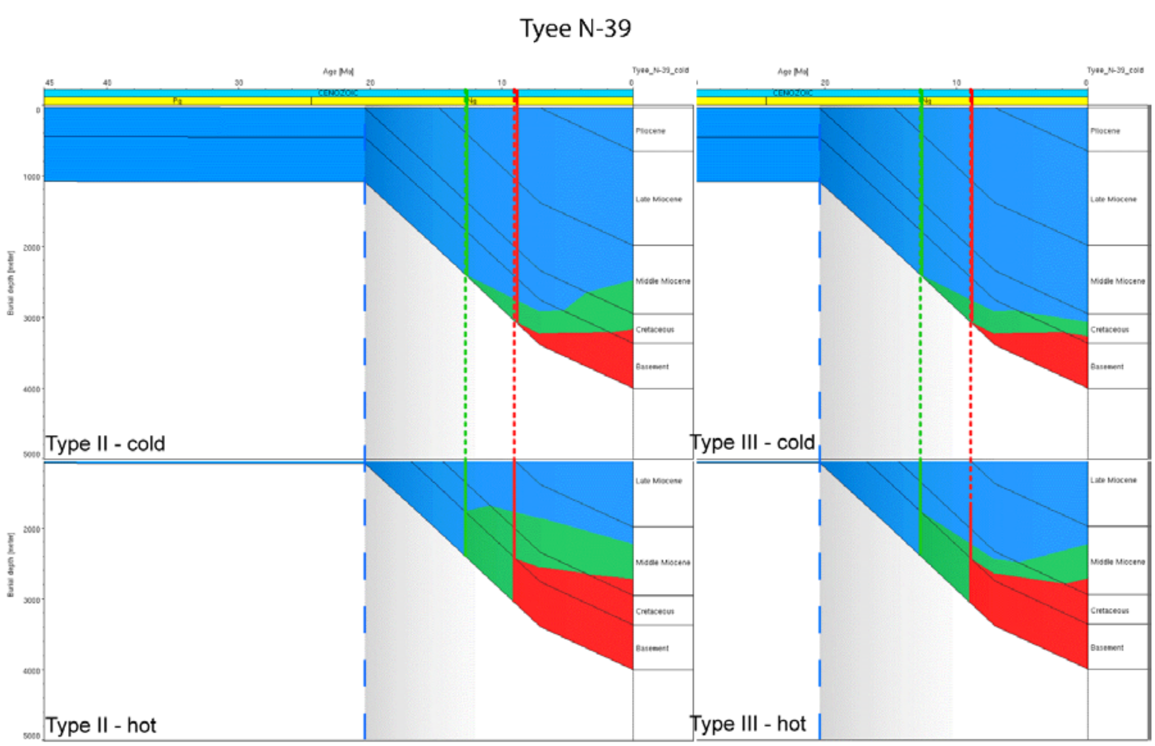

Figure 22. Burial and subsidence history of the Tyee well with an overlay of the modelled hydrocarbon zones. Colours explained in legend of Figure 21.

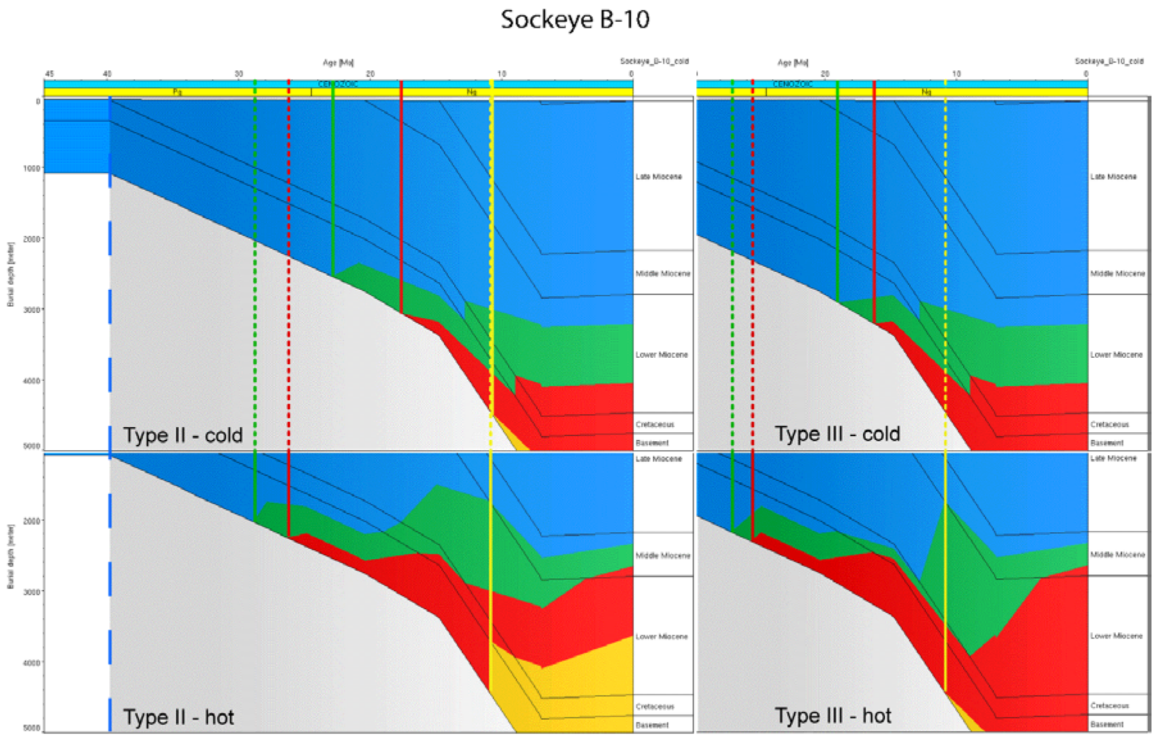

Figure 23. Burial and subsidence history of the Sockeye B-10 well with an overlay of the modelled hydrocarbon zones. Colours as explained in Figure 21.

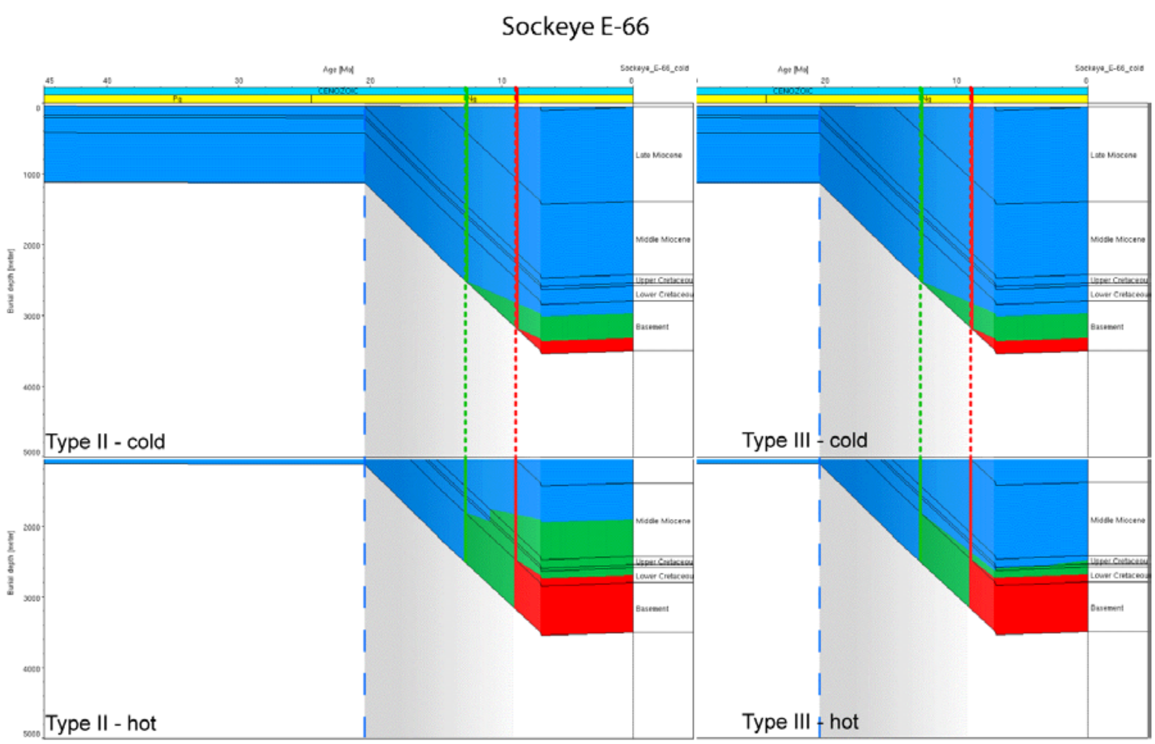

Figure 24. Burial and subsidence history of the Sockeye E-66 well with an overlay of the modelled hydrocarbon zones Colours as explained in legend of Figure 21.

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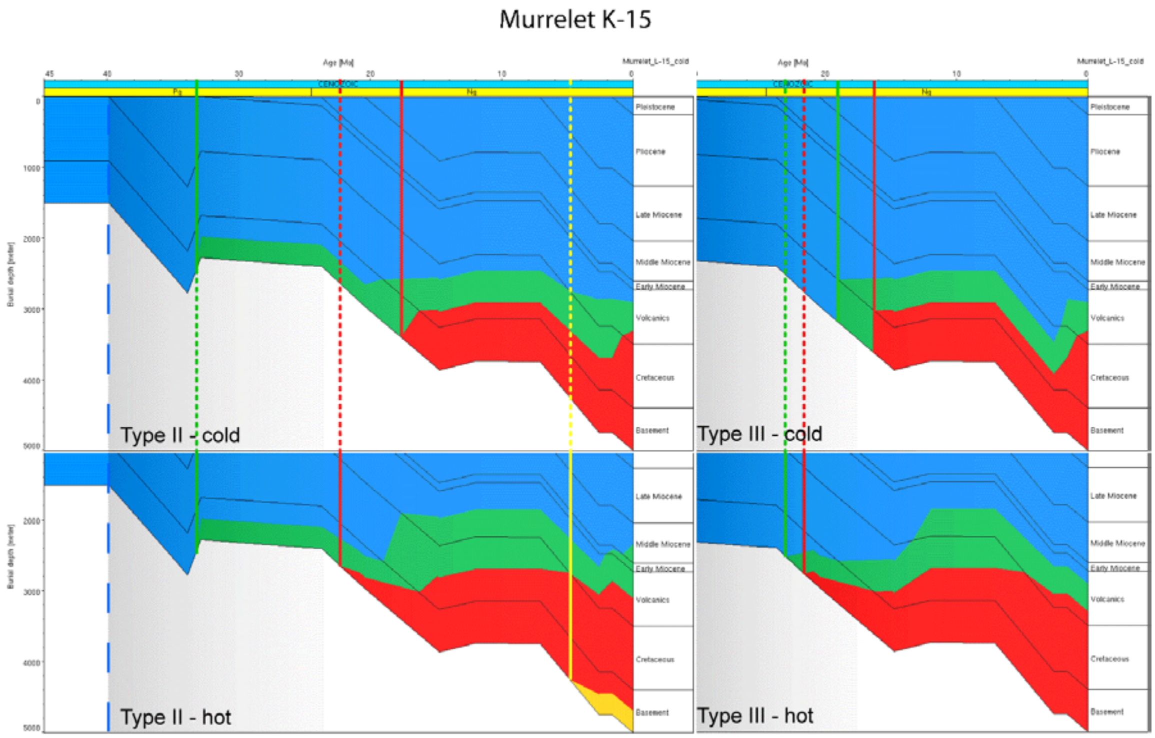

Figure 25. Burial and subsidence history of the Murrelet K-15 well with an overlay of the modelled hydrocarbon zones. Colours as explained in legend of Figure 21.

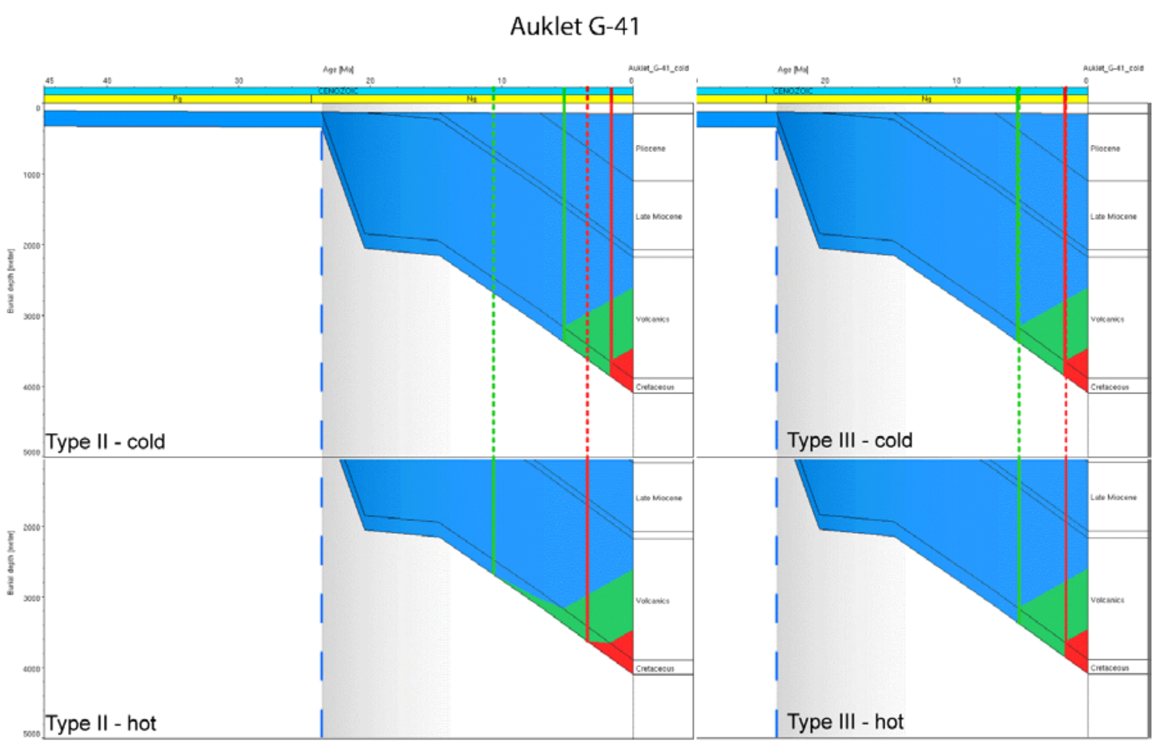

Figure 26. Burial and subsidence history of the Auklet well with an overlay of the modelled hydrocarbon zones. Colours as explained in legend of Figure 21.

Harlequin D-86

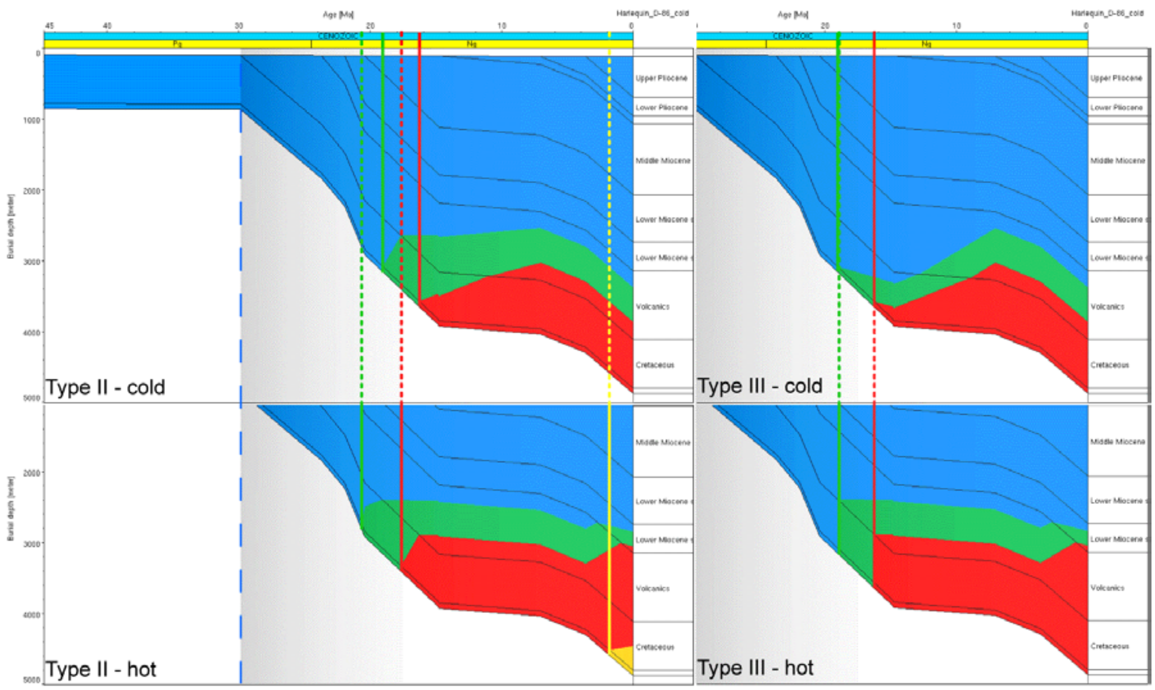

Figure 27. Burial and subsidence history of the Tyee well with an overlay of the modelled hydrocarbon zones. Colours as explained in legend of Figure 21.

Osprey D-36

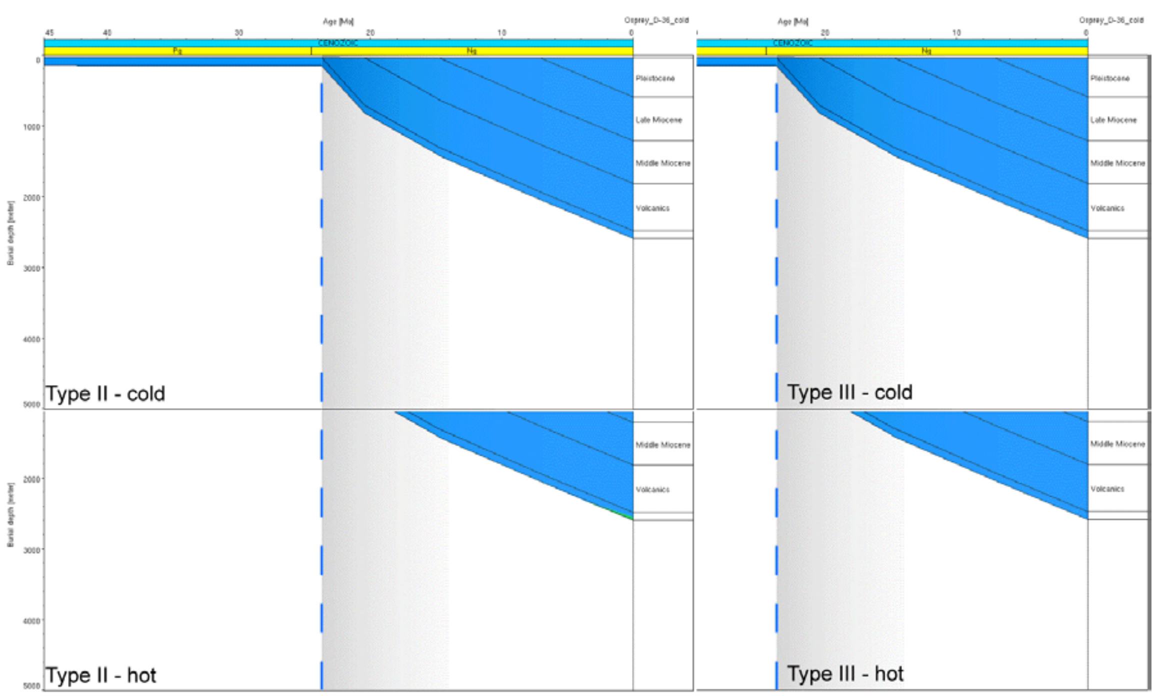

Figure 28. Burial and subsidence history of the Osprey well with an overlay of the modelled hydrocarbon zones. Colours as explained in legend of Figure 21.

7.2 Heat flow

The temperature history in the QCB represents a significant degree of uncertainty in the petroleum generation assessment. Although present day measurements of surficial heat flow have been made (Lewis et al., 1991), the precise temperature history over the Tertiary can only be estimated from an appreciation of the geologic and tectonic situation and history. It is most unlikely that temperature and heat flow were constant with time, or uniform throughout the basin. One of the challenges of the project is to constrain estimates of the temperature history in the QCB.

The heat flow data compiled by Lewis et al. (1991) summarizes available measurements of recent heat flow in the area under study (Figure 29). Compared to the older estimates for the heat flow, which were based on the Shell Anglo well reports, Lewis et al. (1991) propose markedly higher values for the present day heat flow. As the documentation of the older values is sparse it can only be speculated, that during the drilling process not enough time was spent to achieve a thermal equilibrium at the individual well location. They are commonly affected by cooling due to circulating drilling fluids; it is unclear whether the measurements were corrected for this according to Horner's correction method. These well based heat flow estimates have been used for a first set of "Cold" 1D models. Heat flow measurements by Lewis et al. (1991) were used to define a second set of "Hot" 1D models.

Heat flow values from the eight offshore Shell Anglo wells are shown in Figure 29, where they are compared to more recently acquired heat flow measurements by Lewis et al. (1991).

However, both datasets only provide an estimate of the recent heat flow and do not give information about the evolution of heat flow though time. Paleo-heat flow is one of the most sensitive parameters within any basin modelling; it mainly depends on crustal structure and its evolution (e.g. extension, compression, magmatic underplating, or subduction of oceanic crust). In extensional tectonic settings paleo-heat flow is mainly estimated using the crustal and/ or mantle lithospheric (beta-ml) stretching factor (McKenzie, 1978).

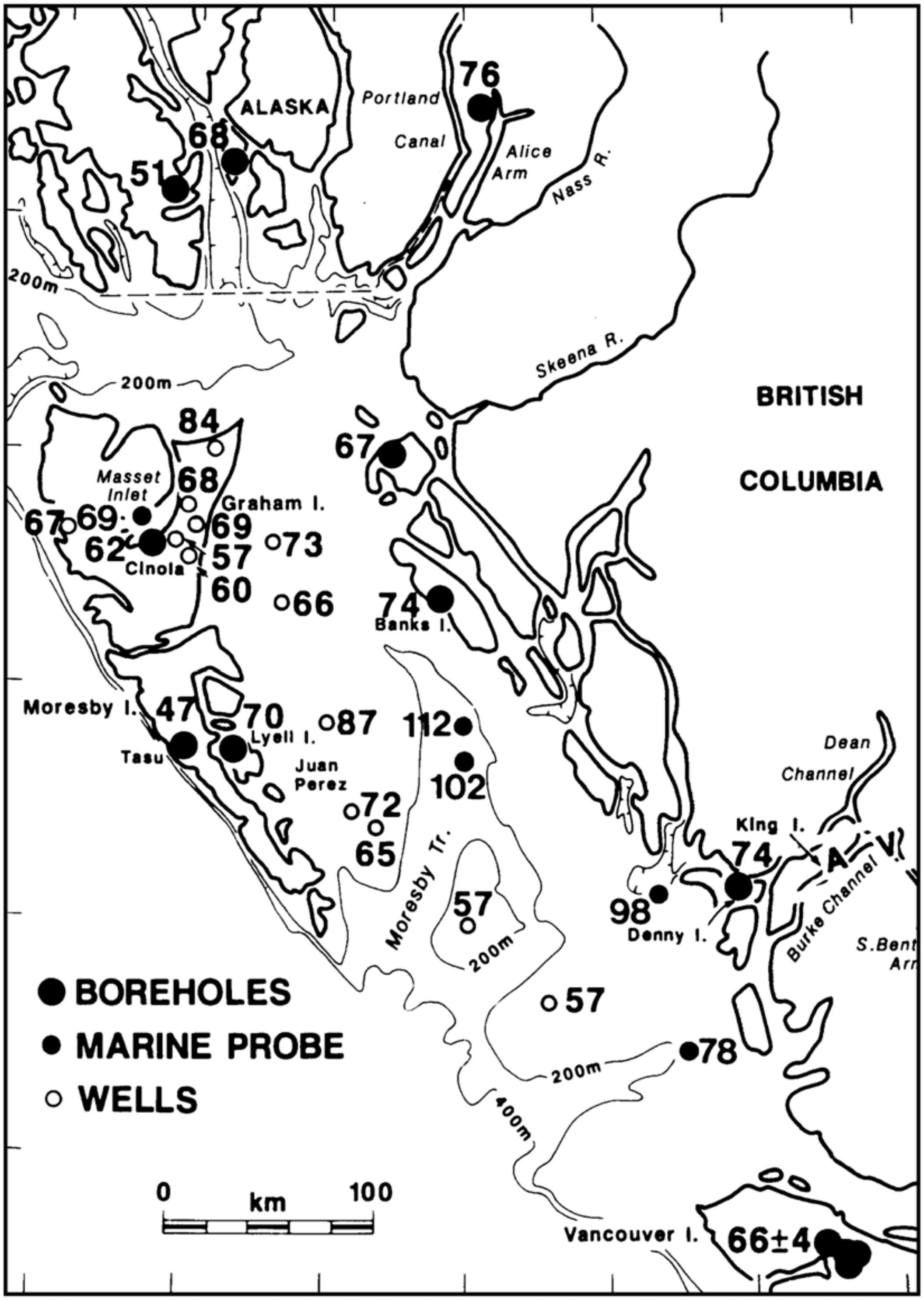

Figure 29. Present heat flow data for QCB compiled by Lewis et al. (1991) summarizes the available measurements of recent heat flow regarding the area under study. Heat flow values for the eight offshore wells, most probably calculated on the base of bottom hole show markedly lower heat flow measurements.

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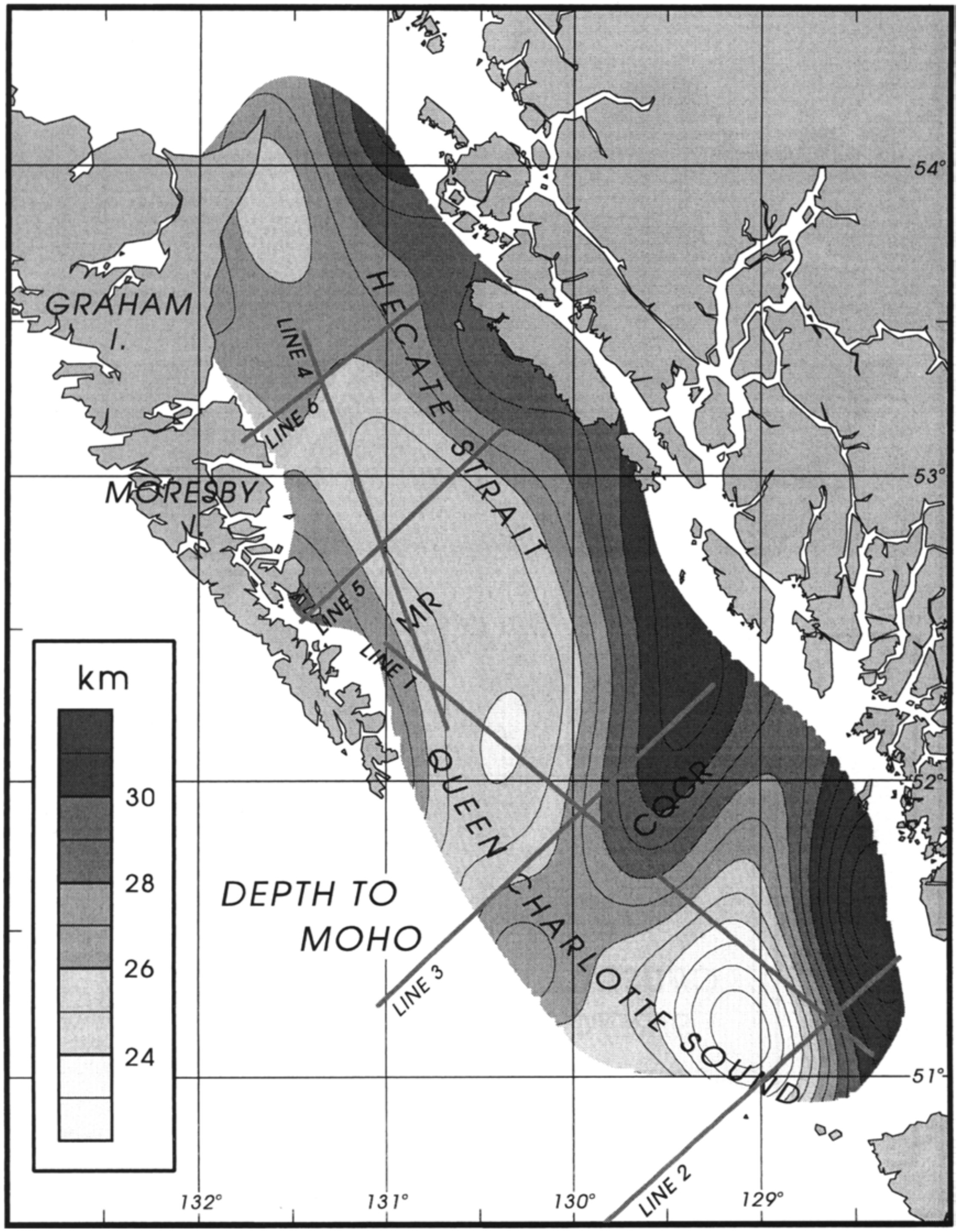

Figure 30. Depth to Moho in Hecate Strait and Queen Charlotte Basin area as interpreted by Dehler et al, (1997). Two zones of extremely thinned crust are present in Queen Charlotte Sound, the southernmost has crust less than 20 km thick and the second, in between Moresby ridge and Central Queen Charlotte Ridge, has crust only 24 km thick. Other areas, e.g. Central Queen Charlotte Ridge, are underlain by distinctly thicker crust.

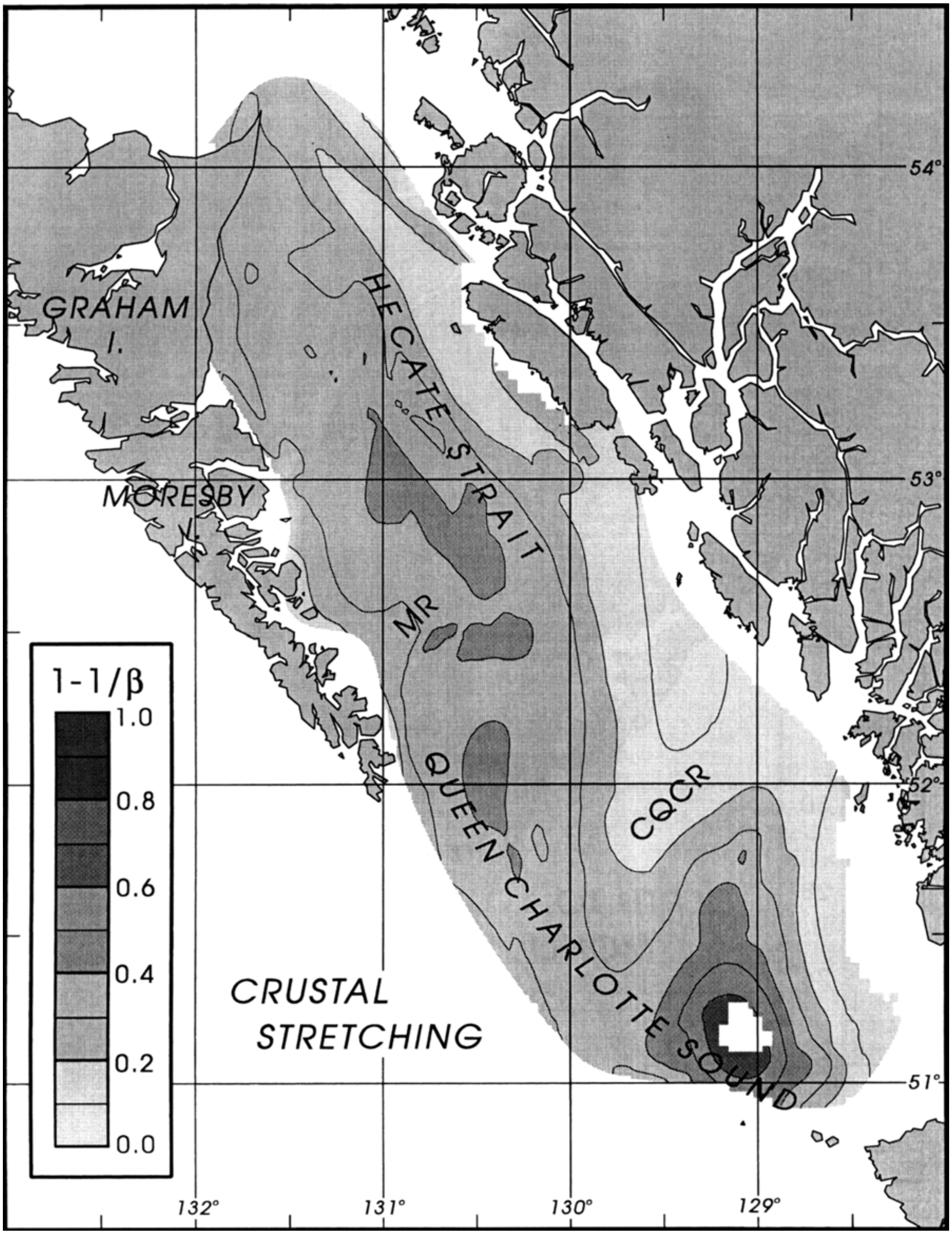

Figure 31. The distribution of the extension observed in the Queen Charlotte Basin region (Dehler et al., 1997) favours a pronounced extension of the southern part (Queen Charlotte Sound) compared to the northern part (Hecate Strait).

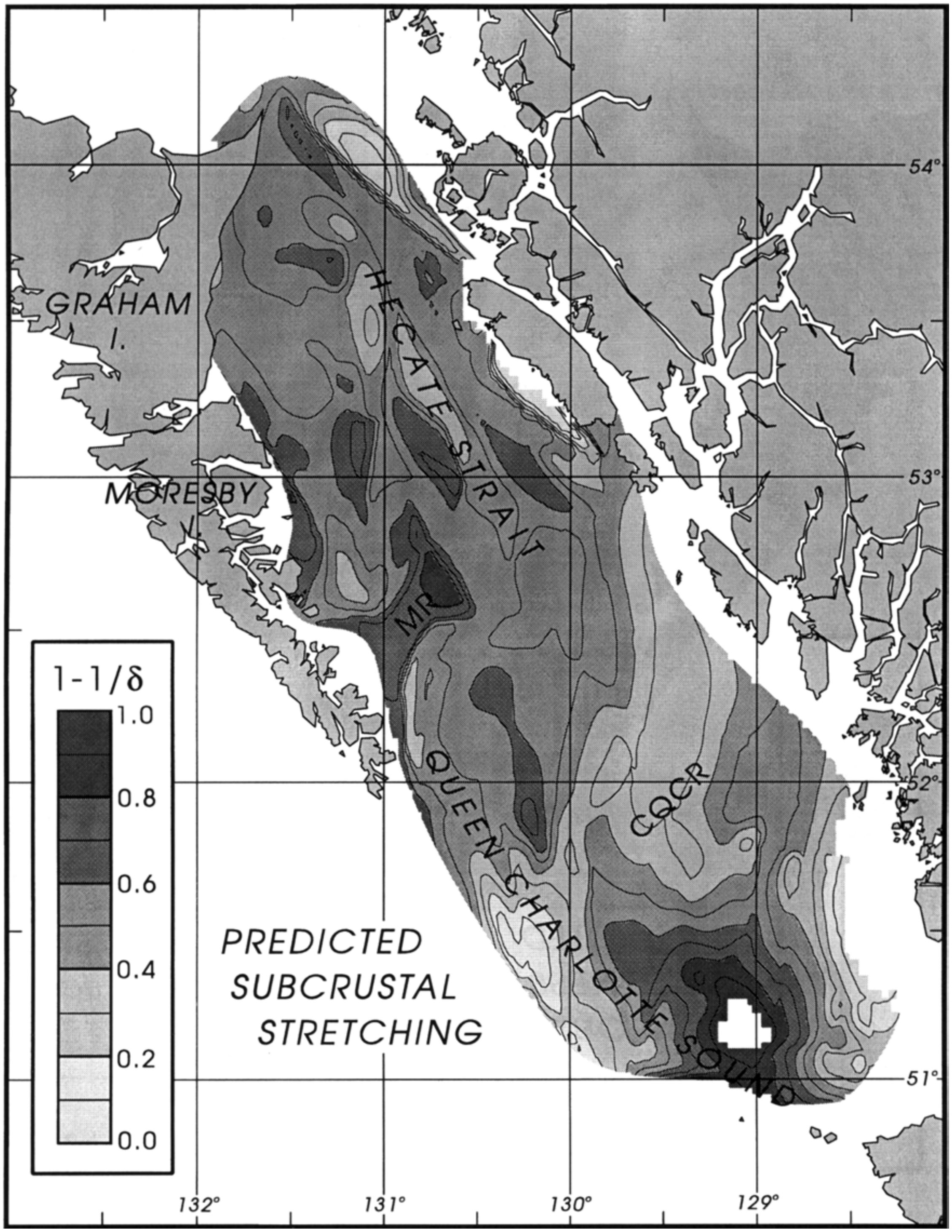

Figure 32. Similar to crustal stretching the predicted sub-crustal stretching (Dehler et al, 1997) also shows the focus of extension within the southern Queen Charlotte Sound area.

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The evolution of paleo-heat flow is strongly influenced by the depth of Moho and plate thickness during the evolution of the basin (Figure 30).

Two zones of extremely thinned crust are present in the southern Queen Charlotte Sound (Figure 30). The southernmost has crust less than 20 km thick and the second, in between Moresby ridge and the Central Queen Charlotte Ridge, has crust only 24 km thick. Other areas, such as the Central Queen Charlotte Ridge and the southeastern part of Queen Charlotte Sound are underlain by distinctly thicker crust. In areas of reduced crustal thickness a higher thermal gradient is expected. Assuming that the initial crustal thickness was uniform, reduced crustal thickness can be directly related to the rifting process itself. Estimates of a time variant basal crustal heat flow during rifting were made, based on theoretical models.

While crustal extension is generally observed in the area under study, it might have originated in different periods of time (propagating rifting) and it definitely is locally inhomogeneous as evident in Figure 31. Similar to crustal stretching the predicted sub-crustal or mantle lithospheric stretching also shows the focus of extension within the south western Queen Charlotte Sound area (Figure 32). This coincidence resembles a general pure shear rifting trend without any obvious asymmetry within the crustal and mantle lithospheric layer. Although it has to be kept in mind that some structures of this area have been affected by strike-slip movements.

The distribution of extension observed in the Queen Charlotte Basin region favours a pronounced extension of the southern part (Queen Charlotte Sound) compared to the northern part (Hecate Strait), and consequently a higher heat flow in the past. Tectonically this could have been caused by distributed strike-slip motion across the margin (Rohr and Dietrich, 1992) or simply regional variation in extension.

According to McKenzie (1978) and Keen (1985) subsidence history of a rifted basin is controlled by the amount of lithospheric thinning, and the amount of heat added to the crust and upper mantle during extension. Two stages can be defined: first, the rifting stage with initial subsidence as response to active extensional processes, and second, a passive thermal subsidence stage, which corresponds to cooling of the crust and mantle toward thermal equilibrium (see e.g. Figures 23 and 27). Once thermal equilibrium is reached, a final depth will be achieved (Parsons & Sclater, 1977). Although the tectonic structure within the QCB region doesn't fully resemble a pure rift basin, as required for the model of McKenzie (1978), a process similar to a pure rifting was assumed for these preliminary models.

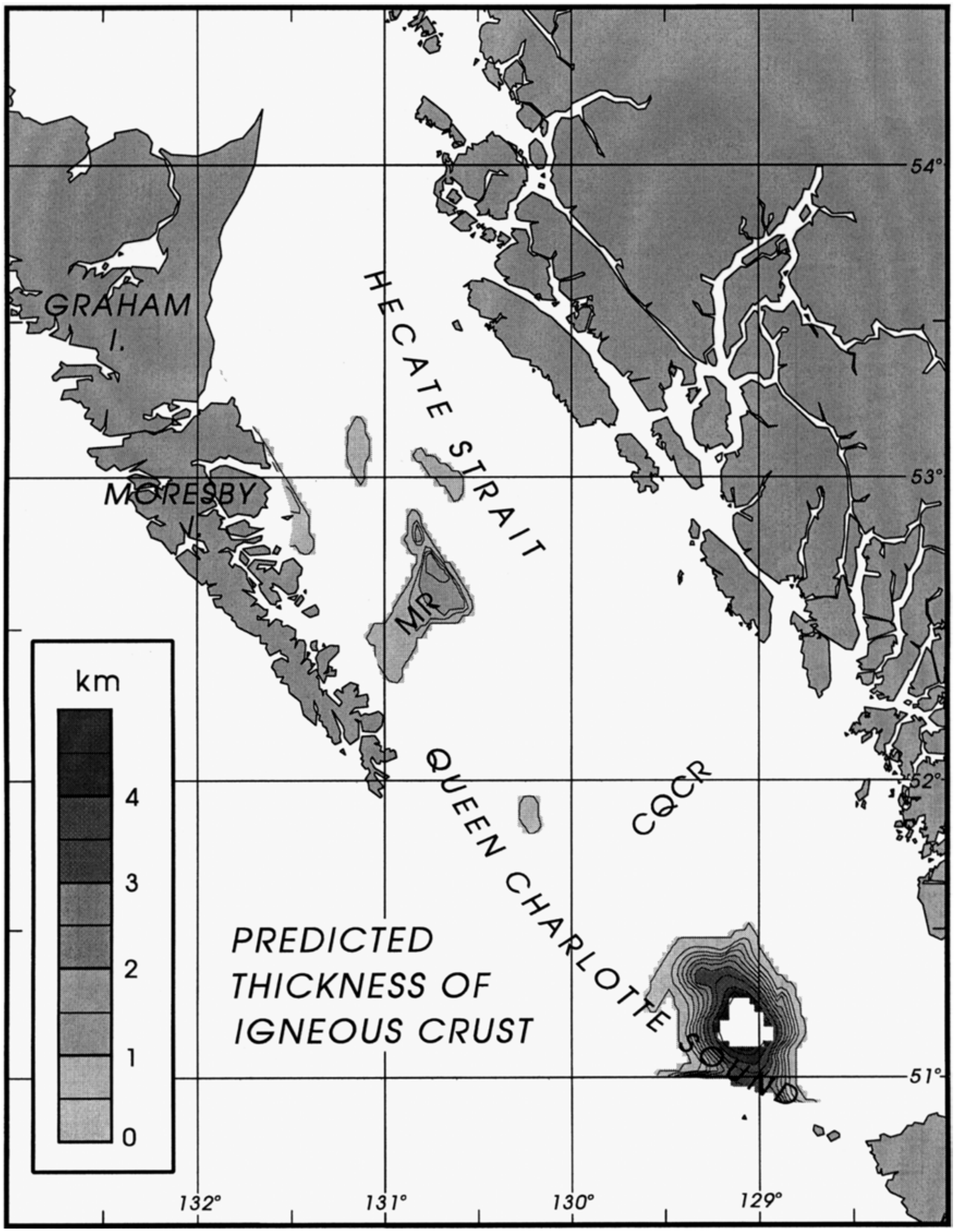

Figure 33. Crustal and mantle lithospheric extension has been strongly focussed onto the south western part of the Queen Charlotte Sound as shown above in Figures 30 to 32. Based on these observations Dehler et al. (1997) predict a maximum of more than 5 km of igneous (underplated) crust to occur under the QCS area.

Yorath and Chase (1983) proposed that a hot spot passed underneath Queen Charlotte Sound, which also would have influenced the thermal regime. Its timing, the evolution of heat flow in the vicinity of mantle plumes and the influence of magmatic underplating related to the hot spot activity could have had a major influence mainly on the maturation of the organic matter in the Mesozoic sediments (see also Figure 33).

Despite this inhomogeneous crustal structure the first set of models presented here employs the same heat flow evolution through time for all the presented models, as only with such a simplified approach can the influence of other important parameters such as stratigraphic control, burial history and erosional events be evaluated. It has to be stated that the basin modelling presented here reflect a conservative approach to the evolution of the basal crustal heat flow, which at least in parts of the basin (south western Hecate Strait and south western Queen Charlotte Sound) is likely to have been more elevated (Figure 34).

Hannigan et al., (2001) generated basin models for the QCB using an estimated heat flow history over the past 200 Ma during which they defined 4 heat pulses around 180 Ma, 80 Ma, 25 Ma and the present (Figure 36). Tests during our basin modeling revealed that the two earlier heat flow pulses used by Hannigan et al. (2001) for their paleo-heat flow model barely affect the maturation of the Tertiary strata.

Most important for the maturation of the Tertiary source rocks is the heat flow evolution related to the Tertiary rifting period. In Figure 36 the differences in the models are very obvious, as Hannigan et al. (2001) have chosen a very high heat flow pulse related to the rifting, which then decreases linearly to heat flow values much lower than the ones observed today (Lewis et al., 1991).

The maximum heat flow of up to 200 mW/m^2 in the Hannigan et al. (2001) model might locally be observed in rift zones, but seems far too high as a general input parameter for basin modelling. Such a high heat flow peak would require a crustal extension factor of 10, according to the McKenzie (1978) model (Figure 35), which seems very unlikely for the area under study.

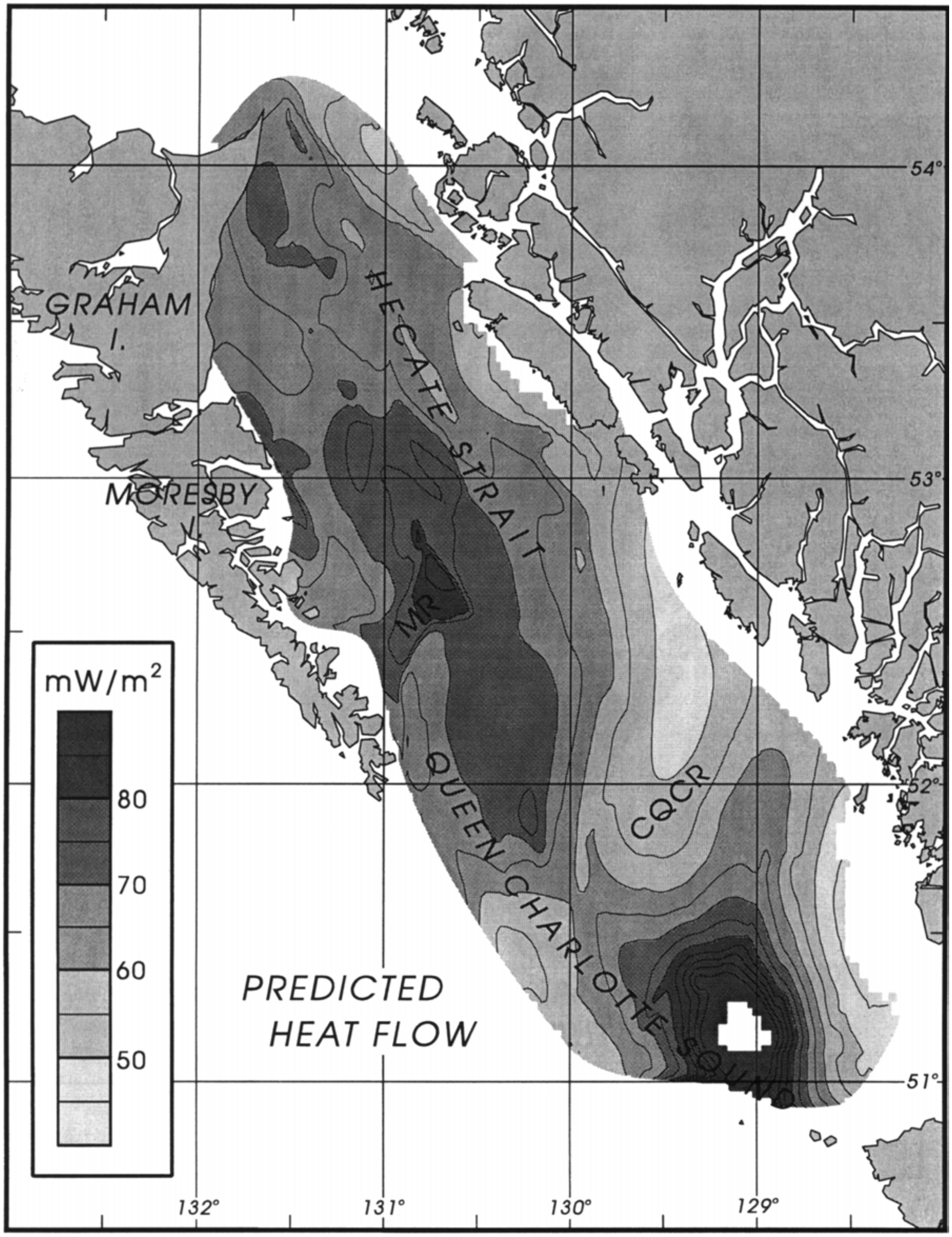

Figure 34. Map of predicted heat flow for Queen Charlotte Basin region (Dehler et al., 1997).

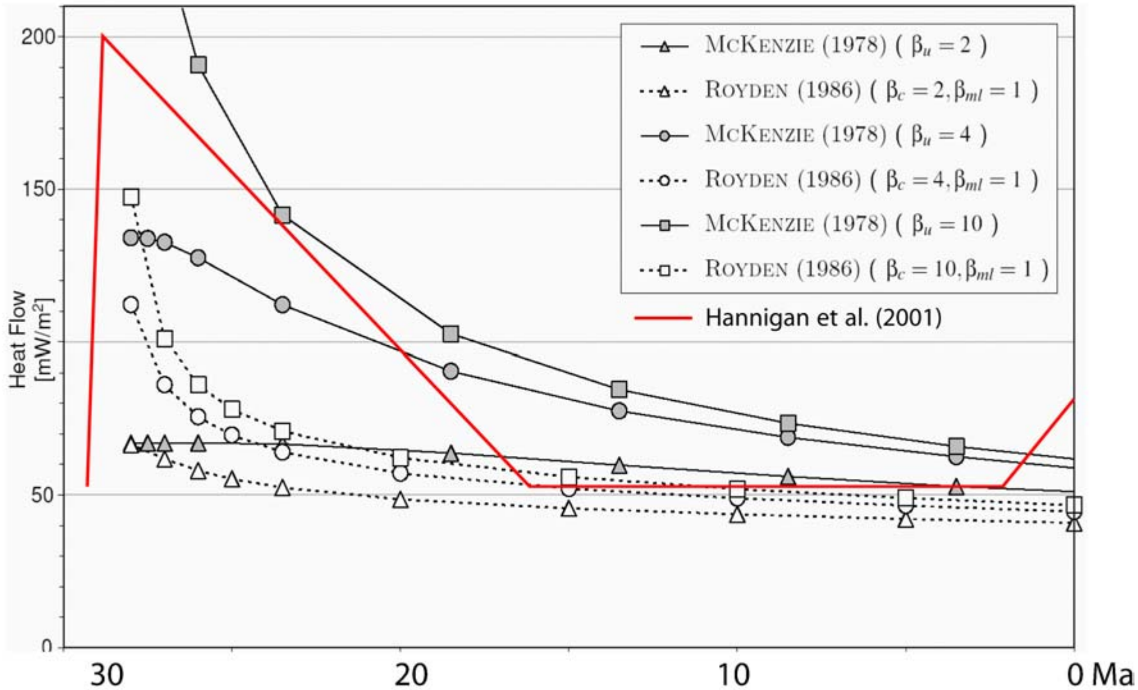

Figure 35.Comparison of the calculated paleo-heat flow (Schuemann, 2002). The figure shows various pure shear rifting models according to McKenzie et al. (1978) and further lower plate simple shear models, calculated according to Royden (1986). The differences to the overlain heat flow model Hannigan et al. (2001) are obvious. The models used in this study reflect a McKenzie type scenario with an extension factor of approximately 3-4 (grey circles).

Table 8. Heat flow histories used in this study.

Time (Ma before present)	Cold Scenario (mW/m^2)	Hot Scenario (mW/m^2)
0	60	70
15	60	73
21	65	78
25	70	83
28	80	88
30	90	92
33	100	100
35	60	60
50	55	55
200	55	55

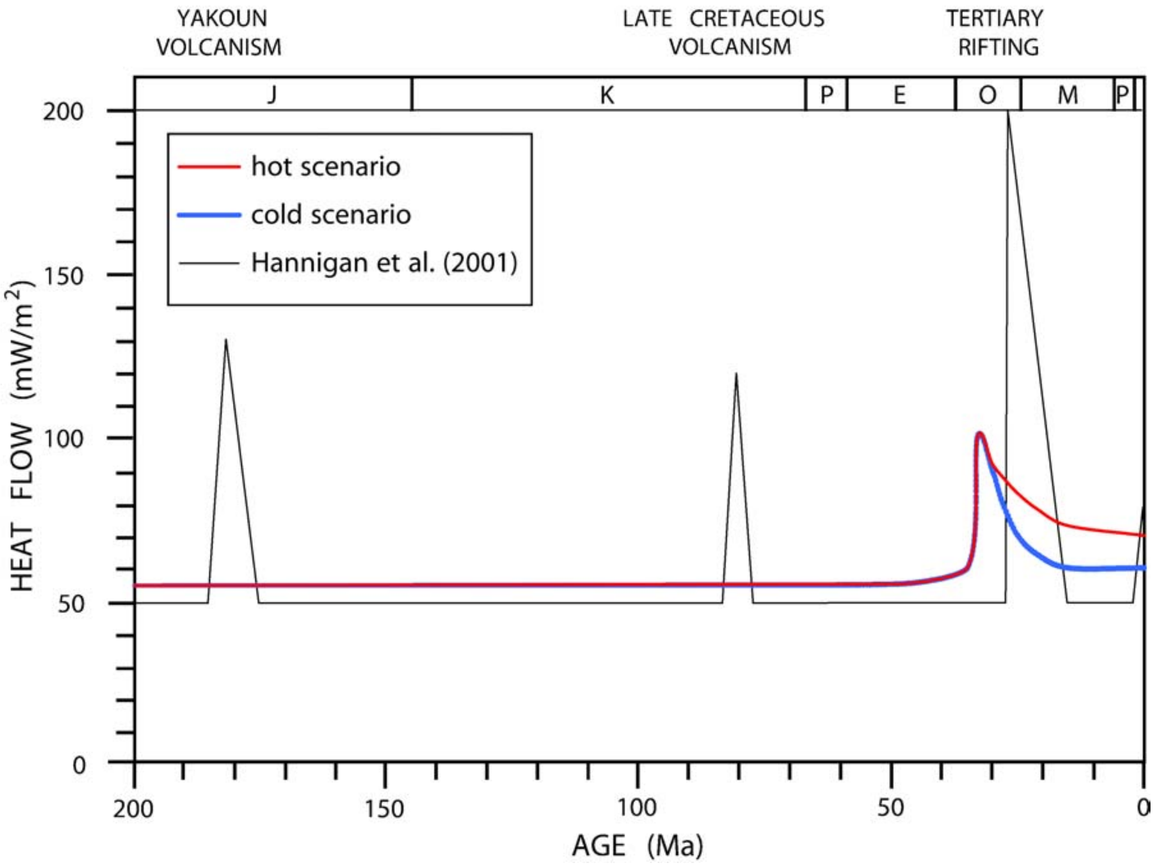

Figure 36. Comparison of the paleo-heat flow model used by Hannigan et al. (2001) to the "Cold" and the "Hot" scenario of this study. As stated in the text the two earlier peaks in the Hannigan et al. (2001) model barely affect the Tertiary strata; these differences in the models are, therefore, of minor interest. Most important for the maturation of the Tertiary source rocks is the heat flow evolution related to the Tertiary rifting period.

Our assumptions for the paleo-heat flow are based on the rifting model of McKenzie (1978), which predicts a less elevated peak and an exponential decrease of the heat flow over a period of approximately 30Ma, as shown in Figure 35 for different crustal stretching factors (2, 4, 10). Instead of employing an extreme high initial heat flow which decreased rapidly, we employed a peak heat flow of 100 mW/m^2 with a much slower exponential decrease for a good general fit of the available vitrinite reflection data (Figures 37 – 39). A lower initial heat flow is predicted by models of McKenzie (1978) for pure shear rifting.

As described earlier (Section 3.4.4), the level of maturation of organic matter in the various parts of the QCB are related to the integrative effect of time and temperature. This means that for a specific maturity there is not a single solution of time and temperature, i.e., a colder sediment package may reach the same maturity as a warmer sediment package, albeit over a longer period. Through the direct determination of level of maturity by vitrinite reflectance measurements from the cuttings samples from the 8 QCB wells, we can generate present-day maturation profiles for the sediments encountered. These profiles are restricted to the maximum depth-age of the sediments, which were drilled and sampled, which for the most part is the Neogene. The vitrinite reflectance profiles are critical to constrain the basin models. As will be shown, the shape of the vitrinite reflectance profiles, and not just the values, are important for us to constrain the most appropriate time-temperature solution.

As will be discussed, selection of the best-estimated heat flow history is absolutely critical to the generative history. Significant errors can be introduced by relatively minor changes in these parameters. Fortunately, our selection of heat flow histories is not totally arbitrary; we are constrained by the measured vitrinite reflectance profiles for the wells. Our selected heat flow histories must at the very least reproduce the real measurements.

It has to be emphasized here, that we used the same two heat flow scenarios for all of the offshore Queen Charlotte Basin wells. As stated above, this assumption neglects the major differences in crustal structure, but was nevertheless preferred, because it allows a better comparison of the various well locations. Given the limited available database it does not seem justified to further refine the models.

Two scenarios (cold and hot) for the basal heat flow, in addition to a constant heat flow, caused by radiogenic elements in the crust, were calculated for each of the wells, and compared to the measured vitrinite reflectance values (Figures 37 – 39). Both scenarios have constant heat flow prior to rifting at ca. 34 Ma. This may not have been so, but as mentioned, earlier heating events would have had little effect due to the shallow burial of the sediment package at that time. The "Cold" scenario has a heat flow rising to a maximum around 33 Ma of 100 mW/m^2 followed by an approximately exponential decrease in heat flow to 60 mW/m^2, based on the available Shell Anglo well reports. The "Hot" scenario has the same rift related heat flow peak, except that the heat flow decays more slowly to a present day value of 70 mW/m^2 (Lewis, 1991). The heat flow values used in our models are listed in Table 8 and illustrated in Figure 33.

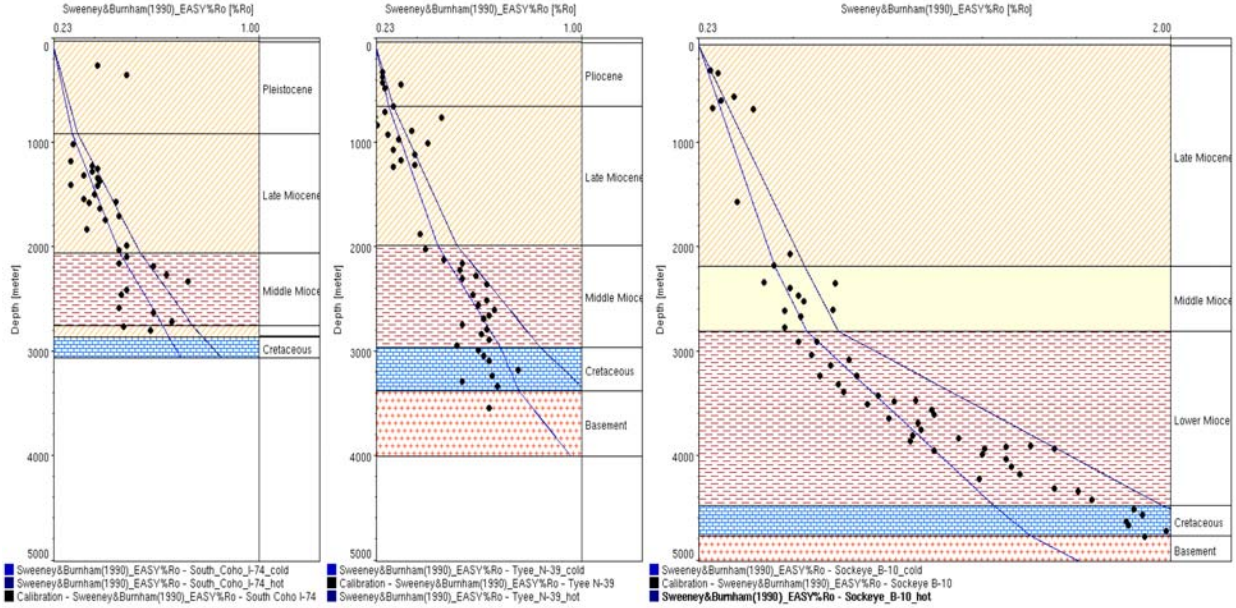

Figure 37. Calibration of the "Cold" and the "Hot" 1D maturation models for the three northernmost offshore wells in Hecate Strait. Although the calibration is necessarily rough due to the poorly constrained age assignments a generally consistent calibration of the preliminary "Cold" model could be achieved, while the "Hot" model seems to overestimate the thermal history.

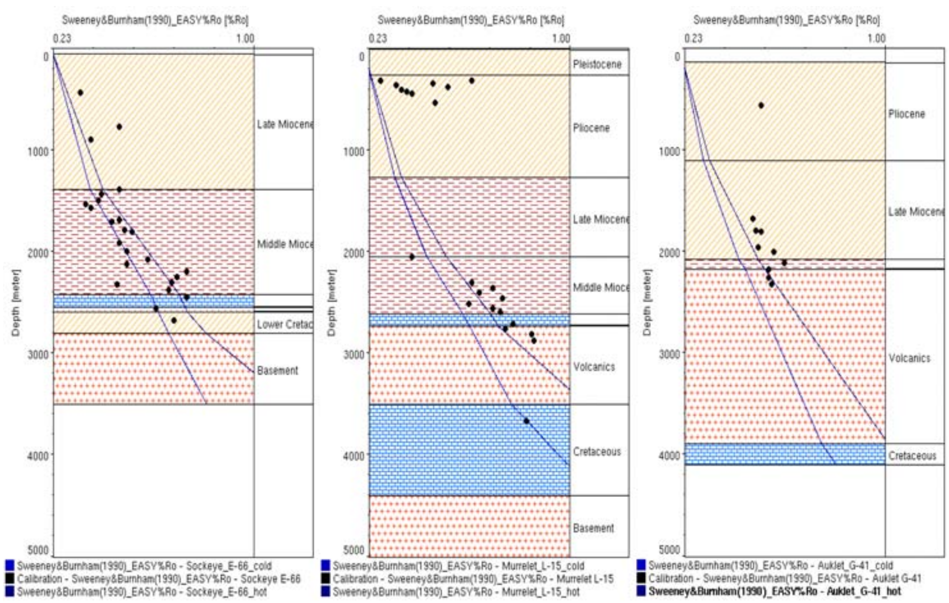

Figure 38. Calibration of the "Cold" and the "Hot" 1D maturation models for the Sockeye E-66 and the Murrelet and the Auklet wells in central Hecate Strait. Less vitrinite reflectance data are available for these three wells; however, a fairly consistent calibration of the preliminary "Hot" model was achieved, while the "Cold" model definitely underestimates the thermal history of the Murrelet and Auklet wells in southern Hecate Strait.

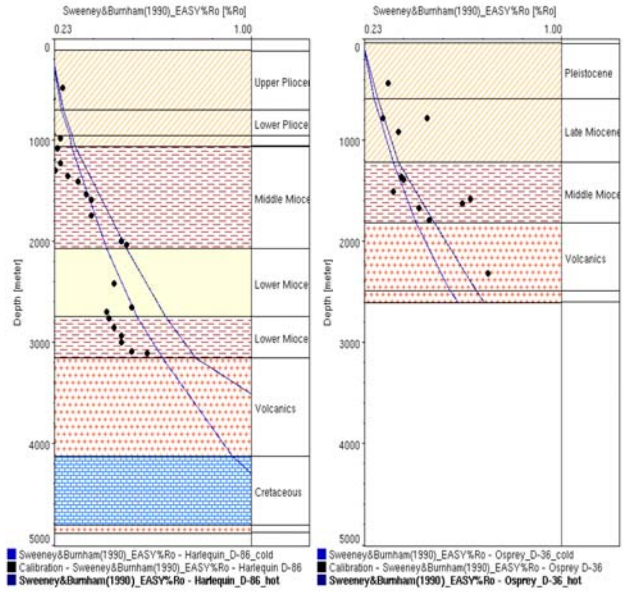

Figure 39. Calibration of the "Cold" and the "Hot" 1D maturation models for the Harlequin and the Osprey well in Queen Charlotte Sound. Few calibration data are available for these wells and the calibration of these southernmost wells seems inconsistent, as maturation levels in the Harlequin well are clearly over estimated, even in the "Cold" model, while the measured maturation levels in the Osprey well are even higher than the ones predicted by the "Hot" model. Although a definite explanation for these observations cannot be given, a correlation to inhomogeneous structures in the crust and/or the mantle lithosphere could be inferred (see also Figures 30, 32 and 33).

For each well hydrocarbon generation windows are given for Type II and Type III kerogens for the "Cold" and the "Hot" scenario (Figures 21 – 28).

The burial and maturation models presented by Hannigan et al. (2001) for the Sockeye B-10 and the Sockeye E-66 wells are compared to our new models for the same two wells (Figures 40 and 41). Hannigan et al. (2001) refer to Type I/II kerogen in the Mesozoic Kunga and Maude groups and to Type III kerogen in the Cretaceous and Tertiary strata. Mature source rocks as shown in their figures (left panel of Figures 40 and 41) imply oil window maturation levels (0.5 – 1.3 %Ro) for the Type I/II organic matter in the older Kunga and Maude groups and gas window maturation levels (0.5 – 2.6%Ro) for the Type III organic matter in the Skonun Formation.

Figure 40 shows the models for Type II source rocks within the Kunga and Maude groups of the Sockeye E-66 well. Although the Mesozoic formations have only been incorporated in a very general manner into our preliminary models, this comparison clearly shows that the model presented by Hannigan et al. (2001), despite its initial very high heat flow peak more or less resembles our "Cold" scenario, which favours a much slower decrease of the elevated heat flow. Compared to our "Hot" model, which seems to be better justified by more recent heat flow measurements (Lewis et al., 1991) and the calibration data (Figure 38, left panel) Hannigan et al. (2001) might have underestimated the paleo-heat flow evolution and therefore their modelled maturation levels are probably too low.

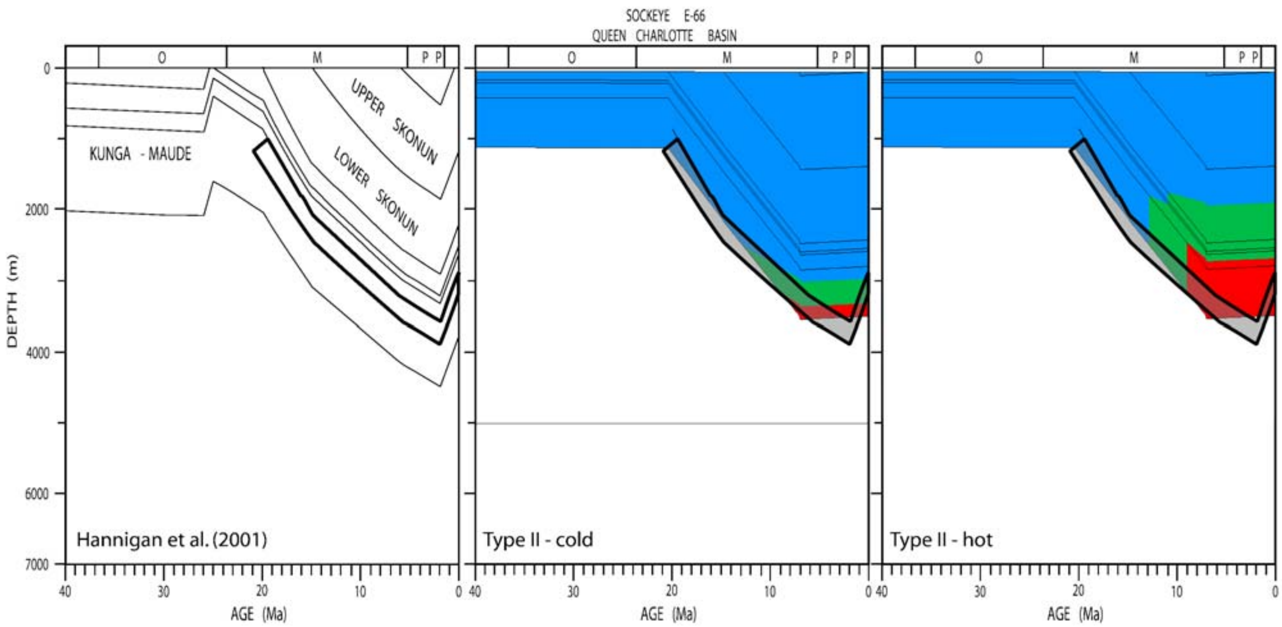

Figure 40. Burial and maturation history modelled for the Sockeye E-66 well. The left panel shows the model presented by Hannigan et al. (2001), which is compared to the "Cold" and the "Hot" model presented in this study. The grey shaded area reflects the oil-window modelled by Hannigan et al. (2001) for the marine source rocks of the Kunga and Maude groups, while the colours in the middle and the right panel refer to the modelled maturation zones for Type II source rocks. Colours as in Figure 21 (see text for further explanation).

The model presented by Hannigan et al. (2001) includes the Kunga and Maude groups as well as Skonun source rocks under the Sockeye B-10 well. As our models are focussed on the Tertiary source rocks no reliable comparison of the proposed maturation of the Kunga and Maude groups in the Hannigan et al. (2001) model is possible. Figure 41 shows our models for both types of kerogen, reflecting the "Cold" scenario. The Type III source rocks, modelled to occur in the Skonun Formation achieve a comparable maturation level in both models.

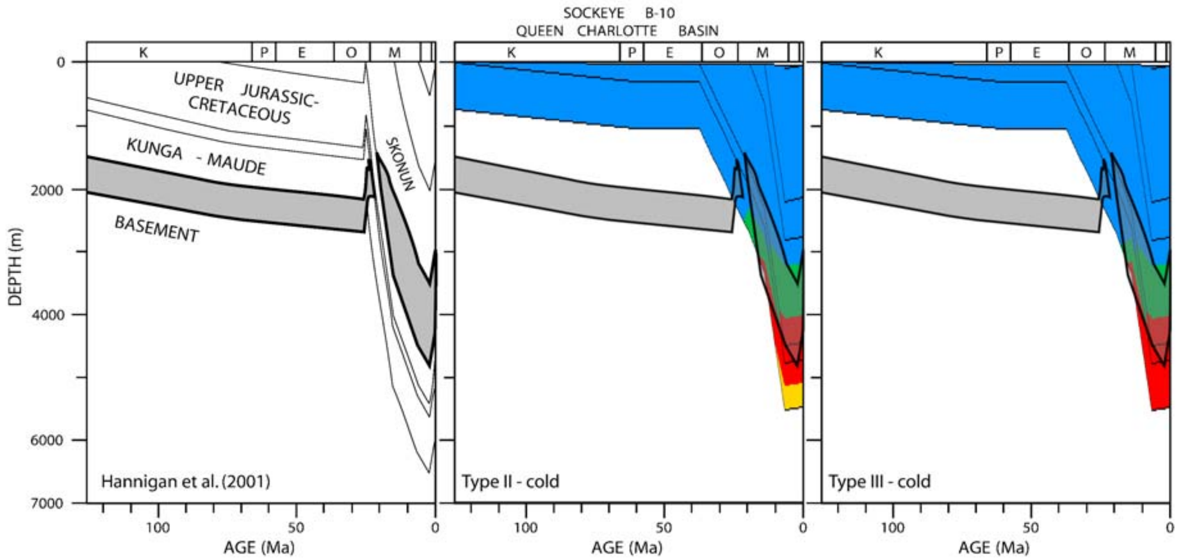

Figure 41. Burial and maturation history modelled for the Sockeye B-10 well. The left panel shows the model presented by Hannigan et al. (2001), which is compared to the "Cold" model for Type II (middle panel) and Type III (right panel) kerogens presented in this study. The gray shaded area indicates the oil- and gas-windows, as modelled by Hannigan et al. (2001) for the Type II source rocks of the Kunga and Maude groups and the Type III source rocks of the Skonun Formation, respectively. The colours in the middle and the right panel refer to the modelled maturation zones according to the "Cold" scenario for Type II (middle panel) and Type III (right panel) source rocks. Colours as in Figure 21 (see text for further explanation).

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8. Delineation of Maturity Zones by Petroleum Systems Models

8.1 Evolution of 1D- Modeling (Sockeye B-10)

The comparison of three different models calculated for the Sockeye B-10 well (kerogen Type II) is shown in Figure 42 using different input parameters, namely stratigraphy and heat flow. Model "a" is based on the original Shell stratigraphy derived from the well report (Shell Canada Ltd., 1968b), whereas models "b" and "c" are based on a new stratigraphic approach by Dietrich (unpublished data). The stratigraphy for model "c", the "Cold" scenario in this report, is adopted unchanged from the stratigraphic interpretation by Dietrich. In this, we include the delineation of a Cretaceous layer, as well as different layers for the Lower, Middle and Late Miocene. The same classification is the base for model "b" in Figure 42, but additional layers were added based on the lithological description of the well samples (Shell Canada Ltd., 1968b).

This comparison of the original stratigraphy by Shell and the new approach by Dietrich reveals significant differences. The Shell stratigraphy includes strata for Eocene up to Quaternary, whereas the stratigraphy by Dietrich ranges from Jurassic/ Cretaceous up to the Late Miocene over the same total depth range. In addition to the differences in time range, there are significant differences in the burial of sedimentary layers. For the top of Late Miocene for example, the difference in burial depth is over 1000 m. These differences are associated with different timing of the layers and therefore with a different burial history and maturity of the strata.

The timing of the main layers of the two stratigraphic interpretations is based on the international stratigraphic time table, whereas the timing of the additional layers in models "a" and "b" is related to the type of sediment. Here the sedimentation of fine-grained sediments is considered to be a longer term process than the sedimentation of coarse-grained sediments. This characterization of the different time steps is linked with uncertainties, which become larger with the increase in additional layers due to the increased number of unknowns. Because of the lack of well-constrained, detailed time constraints, a simplified stratigraphy of Dietrich is used for modeling the 8 QCB offshore wells.

Differences in stratigraphic ages and hence timing have a significant impact on the calculated maturity of the strata. This is illustrated in Figure 42. For model "a" at 24 Ma, the strata in a depth of 2,000 m attains oil window conditions (green), whereas in model "b" the oil window conditions starts substantially later at 17 Ma (at 3,300 m). In model "c" 25 Ma the oil window starts at a depth of 2,500 m.

Gas window conditions (red) start at 24 Ma and 2,700 m for model "a", in contrast to 13 Ma at 3,900 m for model "b" and 18 Ma at 3,100 m for model "c". Similarly, overmature units start at 19 Ma at 3,300 m in model "a", 8 Ma at 5,000 m in model "b" and 12 Ma at 4,500 m in model "c".

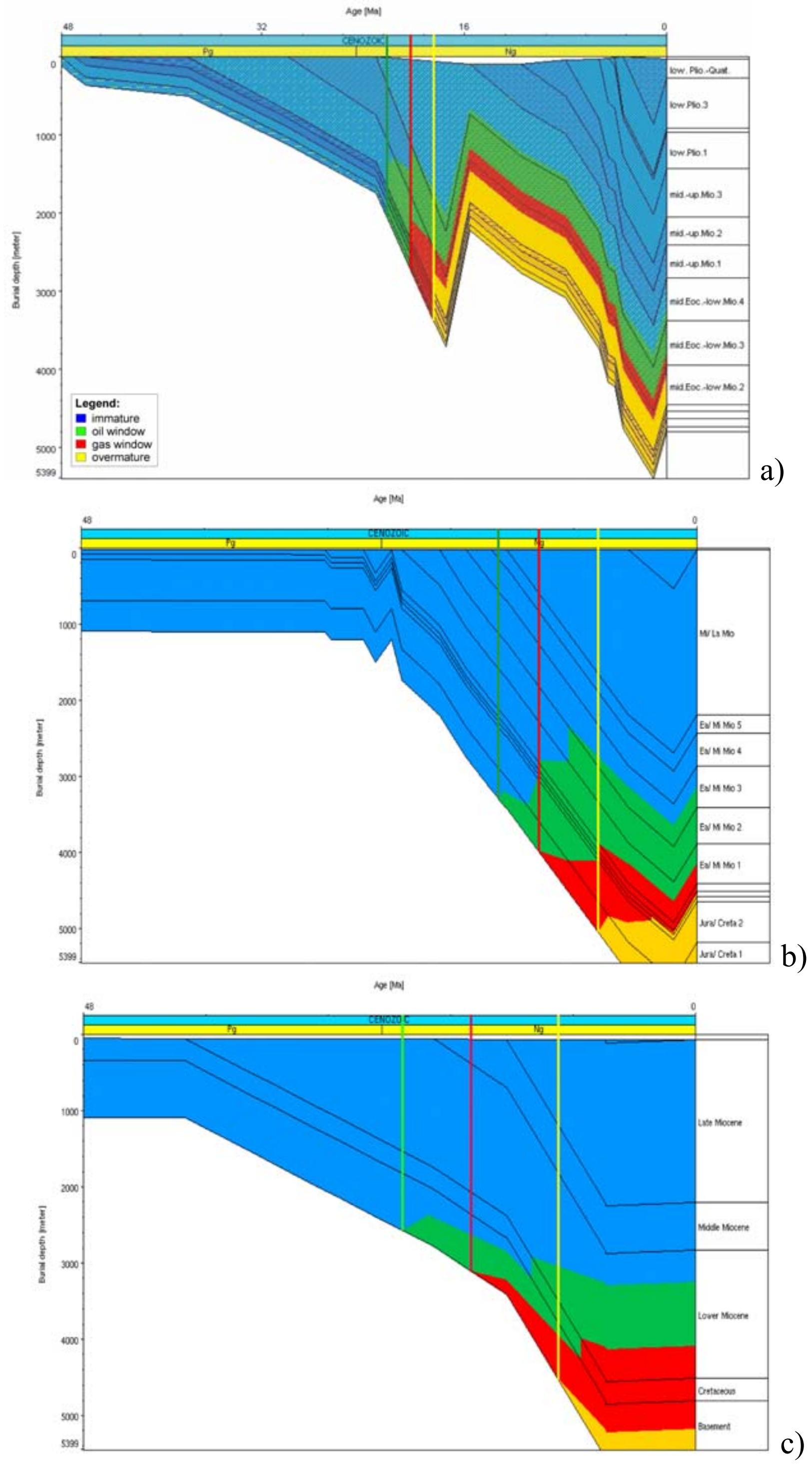

Figure 42. Different models (cold scenario) for Sockeye B-10 for Type II kerogen; colours indicate immature, oil and gas window, and overmature strata; vertical lines indicate time for start of oil window (green), gas window (red), and overmature strata (yellow) Model a.) stratigraphy by Shell Canada (1968b,; b.) and c.) stratigraphy by Dietrich (unpublished data).

In addition to the starting times for the different hydrocarbon zones, the three models also exhibit significant differences based on the thickness of the sedimentary strata, which varies under these conditions. For example, at 0 Ma model “a” contains ca. 700 m of strata in the oil window and ca. 200 m of strata in the gas window. For the same time, in model “b” the thicknesses are 900 m in the oil window and 500 m in the gas window. Model “c” has larger mature zones of ca. 800 m in the oil window and ca. 1,000 m in the gas window.

Although timing is one of the most crucial factors for basin modeling, the differences described above for the different hydrocarbon zones in the three models will also have a significant impact on different heat flow histories, as well as the presence of other features, such as erosional events.

8.2 Basin-wide Maturation Systematics

A basin scale comparison of source rock maturation zones is undertaken here using the output from the 1-D models in Section 7.1 as calibrated to the measured vitrinite reflectance data (Section 6.3). This treatment is largely restricted to Cenozoic units. Present day maturity zonation can be extrapolated to older units, but only reflects a minimum value, as higher maturation could have been achieved prior to the Cenozoic. Two scenarios are tested, the “Cold” and “Hot” Scenarios. The former uses a somewhat lower heat flow for the basin than the latter, as discussed before in this report. The “Hot” Scenario, is the more likely case, because the calculated maturities of this model better fit the measured vitrinite reflectances for the offshore wells.

Figure 43 (“Cold” Scenario) and Figure 44 (“Hot” Scenario) show for each of the eight wells, the 4 different maturity windows (immature, mature oil, mature gas and overmature) for 5 discrete time slices of 30, 20, 10, 5 and 0 Ma. The total depth (TD) of the well is also shown for comparison.

The critical observations in Figures 43 and 44 are:

- None of the Cenozoic units were mature at 30 Ma, with the exception of the Murrelet K-15.
- Only minor hydrocarbon generation occurred in some of the wells at 20 Ma
- By 10 Ma most of the Cenozoic units in the QCB had reached maturity and were generating hydrocarbons. The exception is the Osprey well, that was not drilled deep enough to encounter mature units.
- For the older ages, differences between the “Cold” vs. “Hot” Scenarios are not readily apparent. This supports that fact that the major time of maturation for the Cenozoic units has been in the last 5-10 Ma.

- Overmature units are modeled for the Sockeye B-10. This is not a feature specific to this well or location, rather it reflects the depth to which this well was drilled.

For comparison, maturity profiles with the 5 time slices of the 8 wells are placed in a regional context for the "Cold" and "Hot" Scenarios in Figures 45 and 46, respectively.

It is important to note that maturation of the Cenozoic in the QCB is quite uniform across the basin, despite significant tectonic activity. Figure 47 illustrates this feature using the "Hot" Scenario, i.e., that approximately the same level of maturity will be encountered at similar depths in the Cenozoic package across the basin. Figure 47 is a cross-section of maturity on a line connecting the 8 wells from NW (Coho) to SE (Osprey). The maturity cross section is shown for the 5 discrete time slices, showing the development of maturity in the basin.

Figure 47 repeats our view that based on maturity significant hydrocarbon generation for the Cenozoic package occurs after 20 Ma. It appears that the centre of the QCB attains the oil window, somewhat sooner than the northern or southern sectors. However, the reader should note the differences in TD between wells, especially that only shallow and therefore, immature units were drilled by the Osprey well.

The lower panel of Figure 48 places the present "Hot" Scenario, Type II kerogen maturity profile onto QCB stratigraphy developed by Dietrich (pers. comm.), shown in the upper panel. From this cross section, we can compare the different units that are presently mature across the basin. The figure also places the maturity of the wells into the present structural framework. From this model, we can extract both the regions and stratigraphic units of the basin that are at various stages of maturity today. This allows us to map the sectors of the QCB that are currently expected to have generative source rocks. It is important to note that we are primarily mapping source maturities for the Cenozoic sediments. There is no implication or assessment of product quality (gas, oil, etc.) or reservoir location or volume in this present treatment.

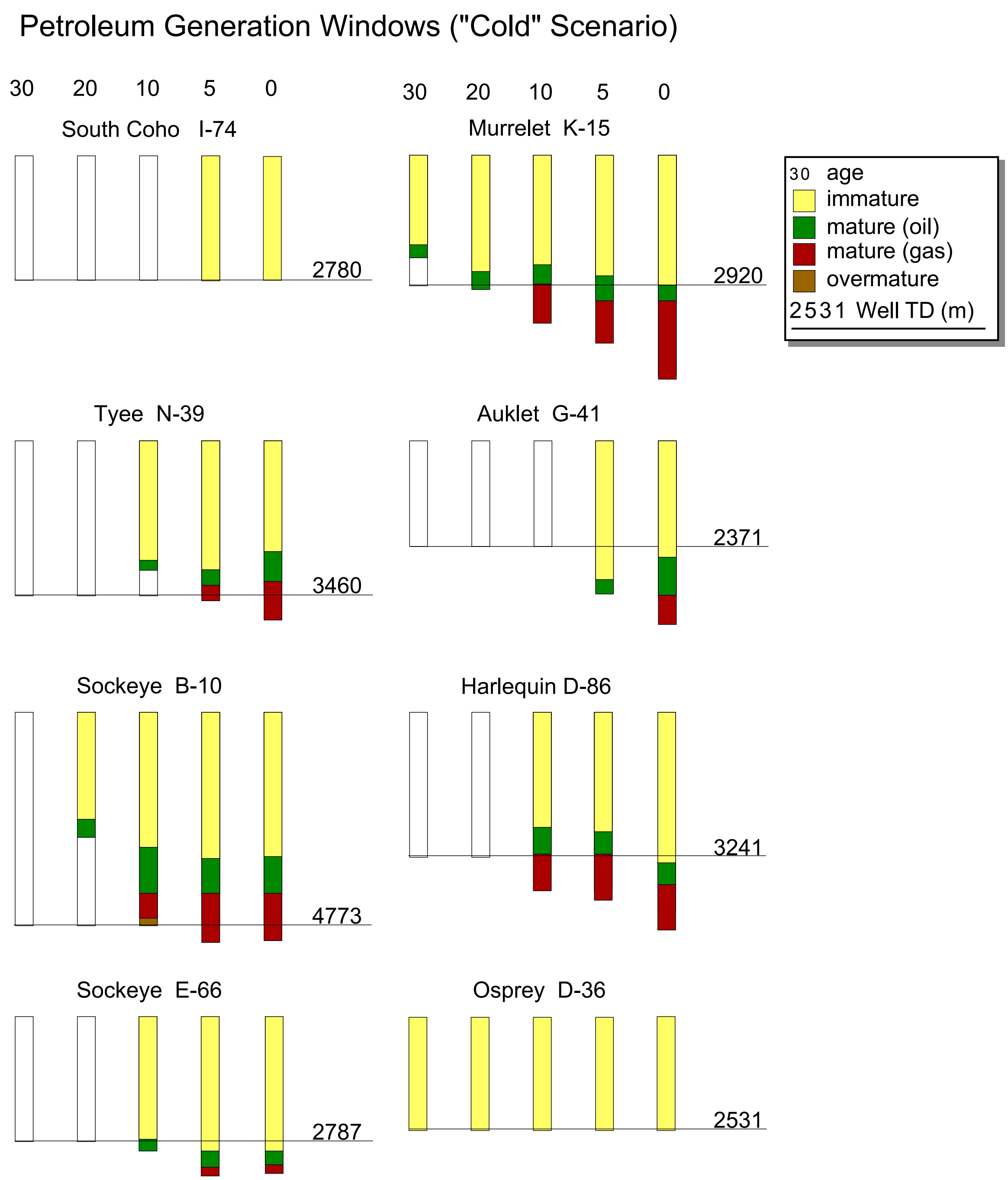

Figure 43. Comparative depth plots of oil and gas zones for offshore wells, based on modelled data – Type II kerogen "Cold" Scenario.

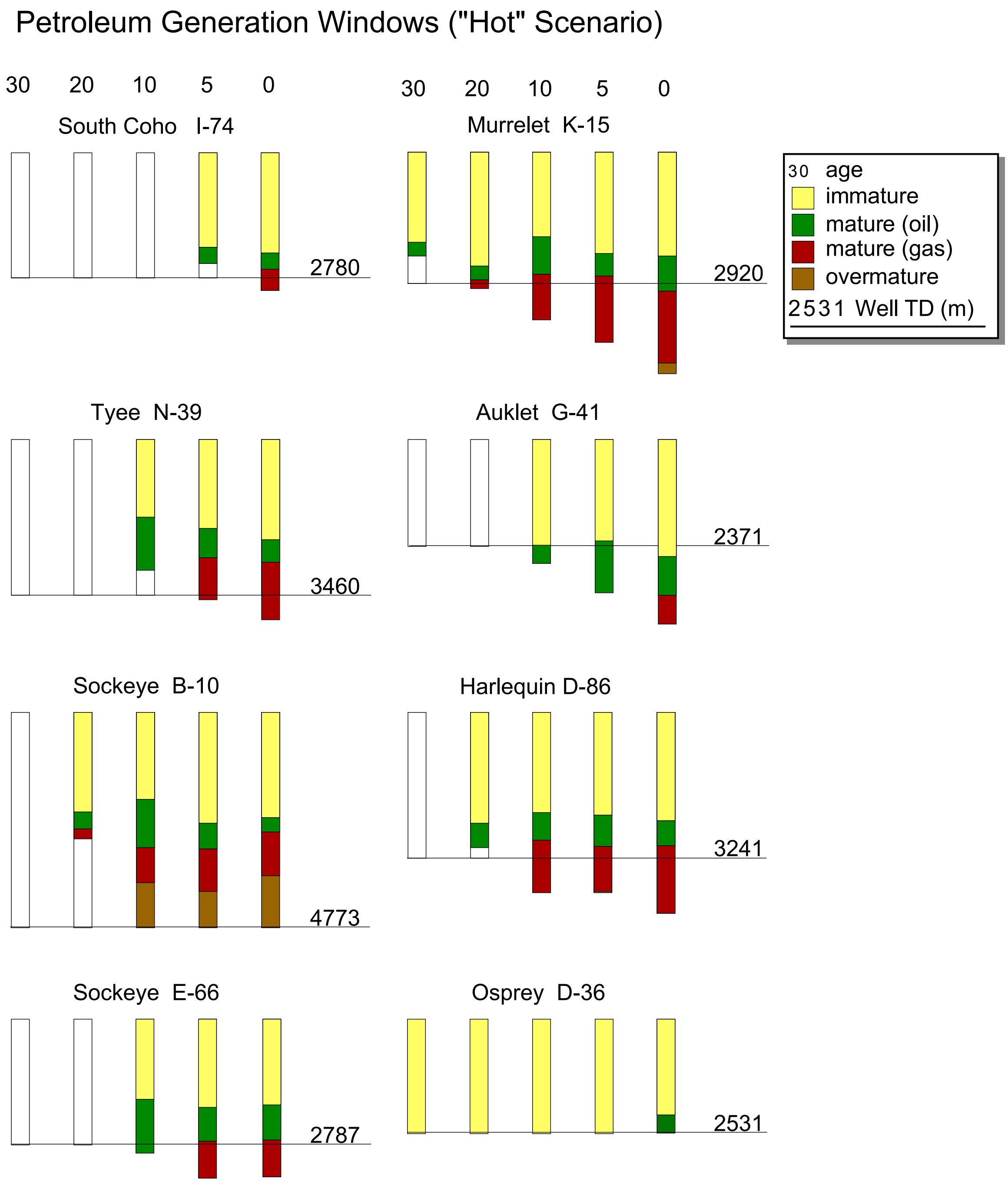

Figure 44. Comparative depth plots of oil and gas zones for offshore QCB wells, based on modelled data – Type II kerogen "Hot" Scenario.

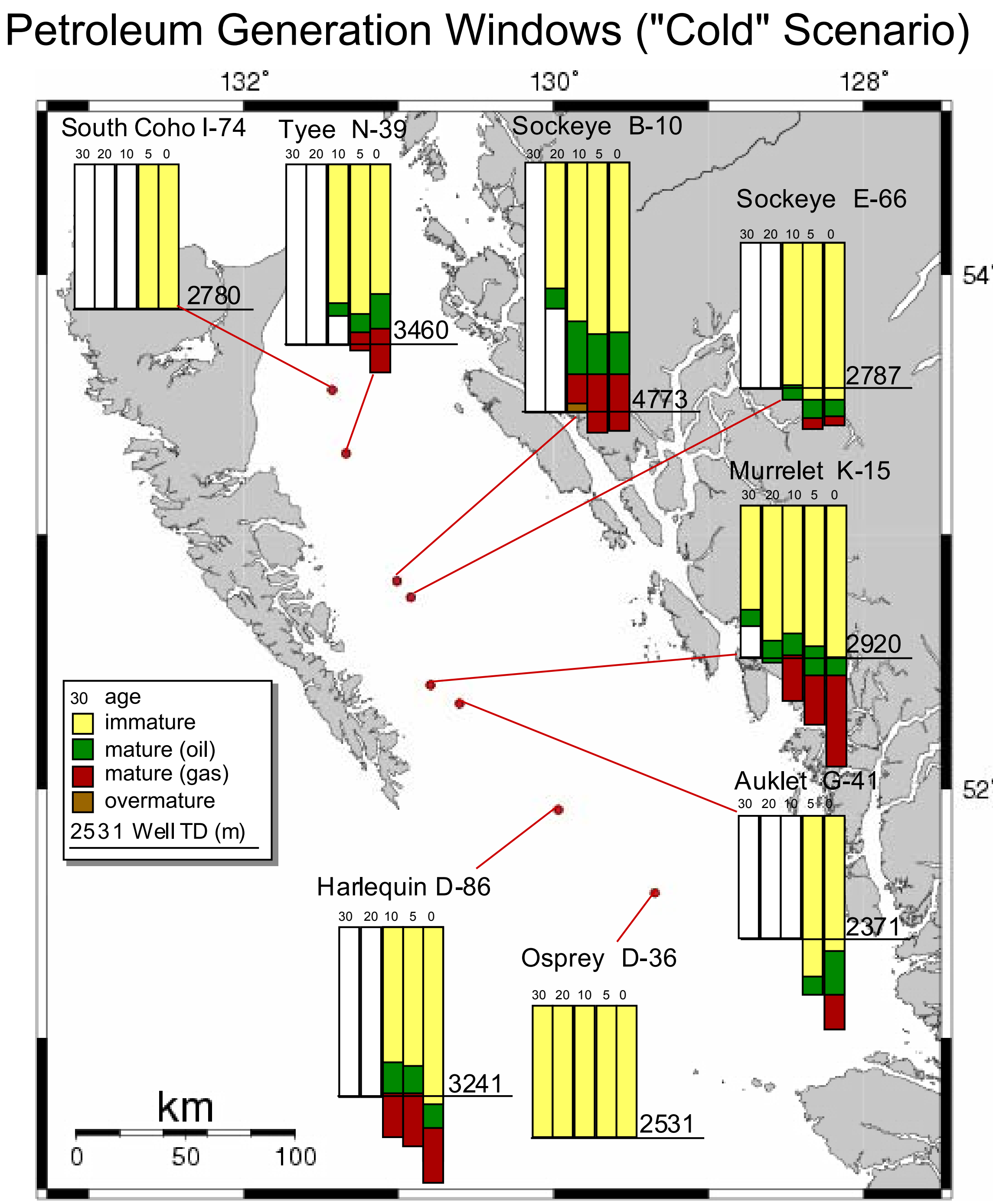

Figure 45. Comparative depth plots of oil and gas zones for offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type II kerogen "Cold" Scenario.

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Petroleum Generation Windows ("Hot" Scenario)

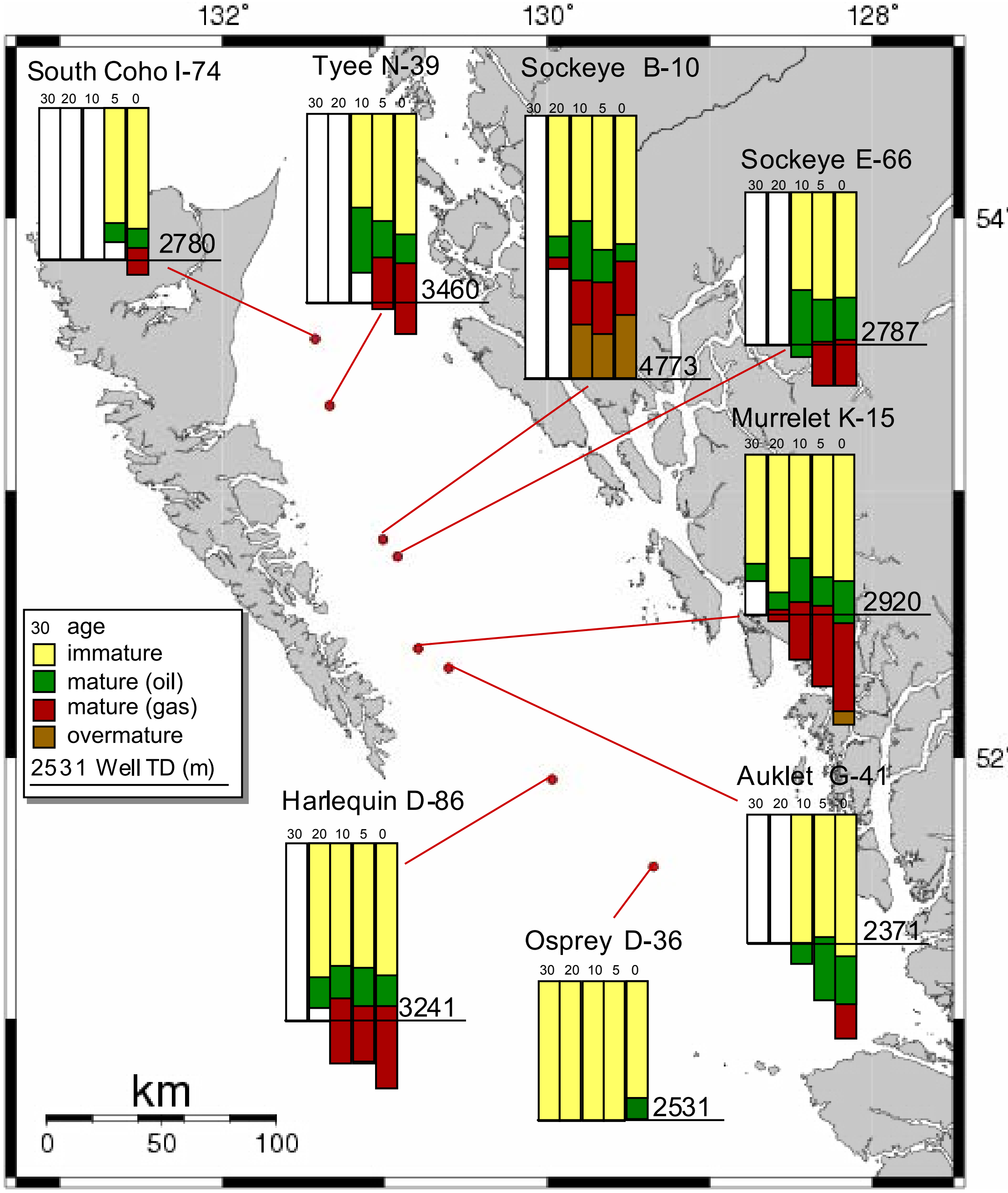

Figure 46. Comparative depth plots of oil and gas zones for offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type II kerogen "Hot" Scenario.

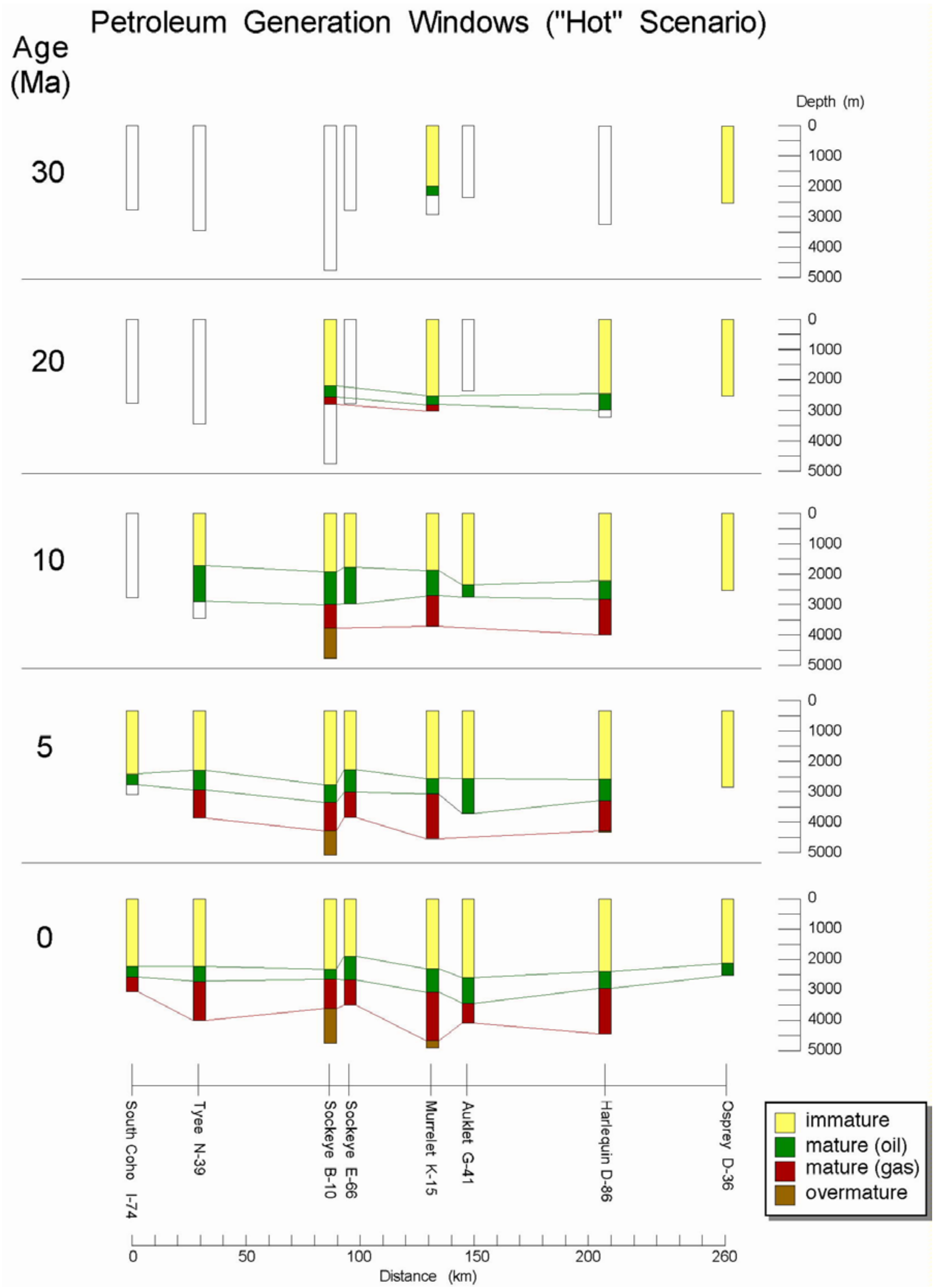

Figure 47. Basin-wide depiction of depth plots for oil and gas windows of offshore QCB wells based on Type II Hot Scenario models.

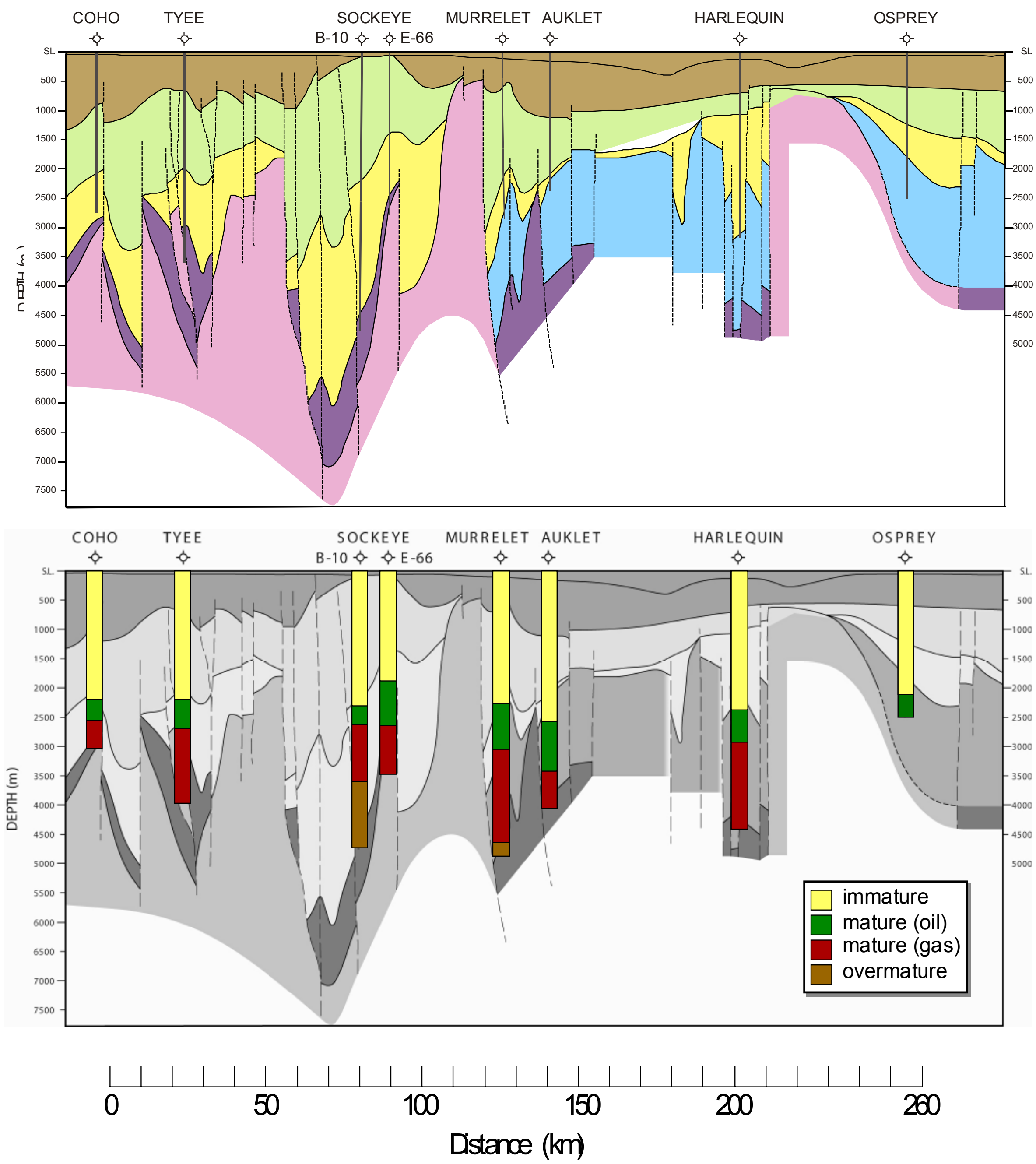

Figure 48. Upper panel: schematic representation of present structural-stratigraphic cross section (NW – SW) connecting offshore QCB wells. Lower panel overlays the oil, gas and overmature zones for the Type II kerogen "Hot" Scenario.

8.3 Petroleum Generation Schnecke Plots

The Petroleum Generation Schnecke plot is a new plot using polar coordinates to illustrate burial history and maturity modeled for the QCB wells over time. Although the diagrams are challenging to interpret at the outset, they visually reveal a large amount of information about the petroleum generative potential of source rocks in a well. Of particular value is the ability to see how the particular well 'evolves" with time, and more easily compare the evolution observed in one well with that in another.

To read the Schnecke plot note that geologic time is represented as the azimuth, with age decreasing counterclockwise from 50 to 0 Ma. The radius of the plot is the burial depth. It increases from the outer rim to the center of the diagram. The maturity zones are colour-coded and overlay the plot.

Prior to 30 Ma the strata in almost all offshore wells are immature and therefore not considered in the plots (Murrelet K-15, kerogen Type II and "Hot" scenario is the only exception which has oil window conditions starting at 33 Ma).

As an example, Figure 49 shows the Schnecke plot for the Cenozoic-late Mesozoic sediments of the Sockeye B-10 well (kerogen Type II, "Cold" scenario).

1) 30 Ma: (Figure 49a) the sediments in the Sockeye B-10 are immature (blue) down to total depth (TD) of 2,250 m.
2) 23 Ma: lowest part of the sediments at 2,550 m depth reaches oil window conditions (green). The increase in maturity between 30 and 20 Ma is accompanied by increasing burial depth from 2,250 m to 2,820 m.
3) 20 Ma: upper 2,400 m of the Cenozoic sediments are immature, whereas from 2,400 m down to the TD of 2,820 m oil window conditions are present (Figure 49b).
4) 19 Ma: sediments reach gas window at 3,070 m.
5) 20 Ma to10 Ma: burial depth increases from 2,820 m to 4,710 m
6) 10 Ma: lower 660 m are in gas window, the underlying 1,025 m in oil window and the upper 3,025 m are immature.
7) Between 10 and 5 Ma (Figure 49c) burial depth increases from 4,710 to 5,530 m with overmature conditions (yellow) occurring around 10 Ma.
8) 5 Ma: overmature in lower 380 m of the strata, followed by 1,100 m in gas window. Oil window is present between 3,275 and 4,050 m and the strata in the upper 3,275 m are immature.
9) 5 to 0 Ma: the burial depth decreases by 30 m from to the TD of the model at 5500 m (Figure 49d) due to an erosional event
10) Today overmature strata are present in lower 350 m, gas window is between 4,050 and 5,150 m, oil window between 3,225 and 4,050 m and upper 3,225 m are immature.

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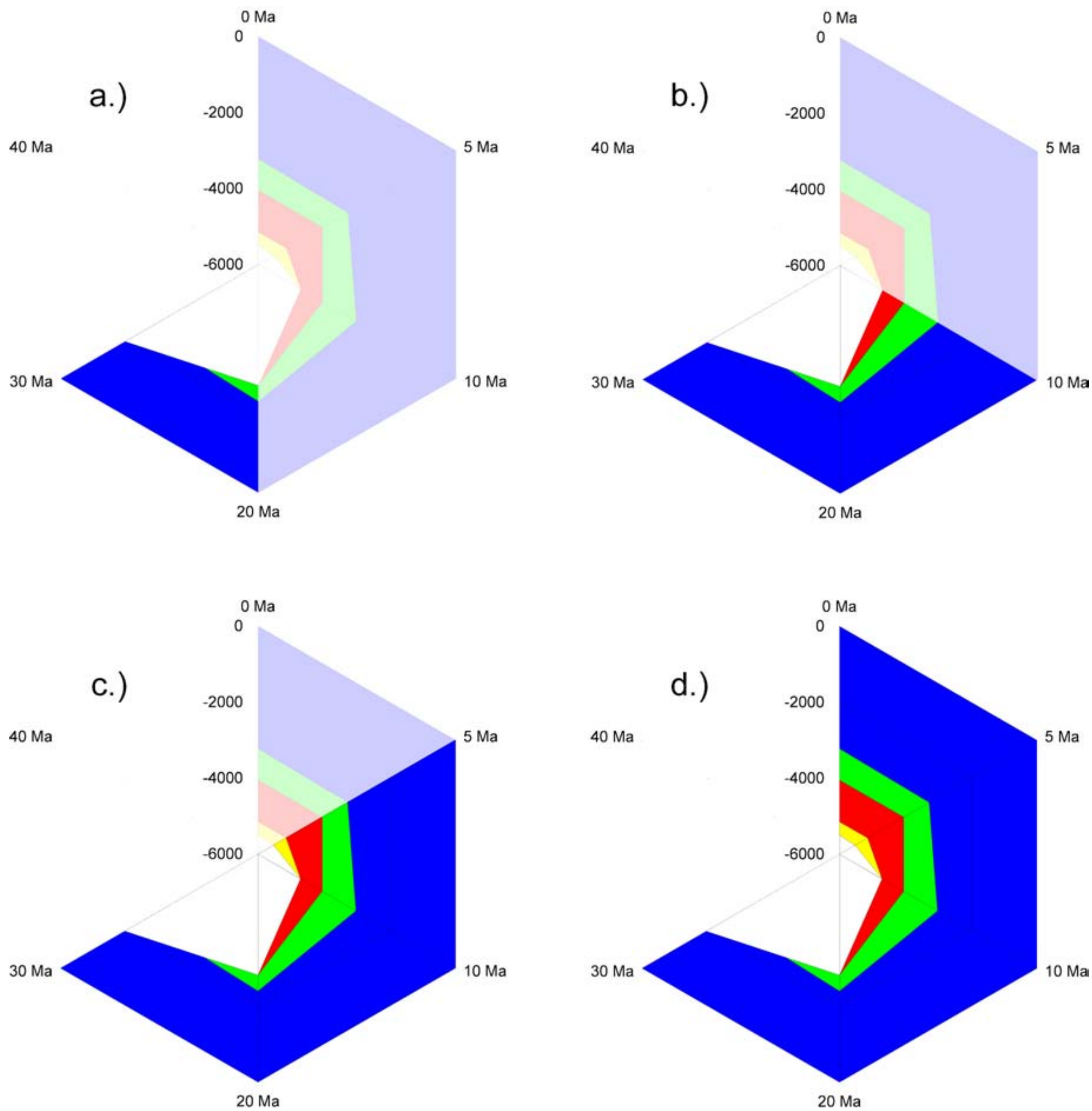

Figure 49. Example of the evolution of a petroleum generation Schnecke plot, based on modelled data for the Sockeye B-10 well – Type II kerogen "Cold" Scenario. See text for description.

8.4 Basin Interpretation using Petroleum Generation Schnecke plot

Figures 49 to 52 show the evolution of maturity and burial depth for the eight offshore wells in QCB, illustrated with Schnecke plots. The maps allow a direct comparison of the calculated maturity and burial depth for the different wells from 30 Ma to 0 Ma. Figure 49 refers to kerogen Type II "Cold" scenario, Figure 50 to kerogen Type II "Hot" scenario, Figure 51 to kerogen Type III "Cold" scenario and Figure 52 to kerogen Type III "Hot" scenario.

For kerogen Type II "Cold" scenario (Figure 49) the highest maturation levels can be recognized in the Sockeye B-10, Murrelet K-15 and Harlequin wells, which are the deepest wells and models in the QCB with computed depths between 4,500 and 6,000 m. The lowest maturations are present in the South Coho and Osprey wells, which are the shallowest wells and hence models in the basin, with depths less than 3,500 m. The same constellation can be recognized for the "Hot" scenario (Figure 50) and for kerogen Type III (Figure 51 and 52).

The recognizable differences in level of maturity in the different wells are mostly related to the above mentioned different total depths of the wells and the resultant models. Figure 53 (kerogen Type II "Hot" scenario) shows a comparison between the Sockeye B-10 as the deepest and the South Coho as the second shallowest well in the basin. This figure illustrates the relation of visible maturation levels between the oil and gas window conditions to the total depth of the model. This comparison reveals an almost uniform depth for the top of the oil and gas window conditions, which is also the case for most of the other offshore wells.

At present day, the top of the oil window is between ca. 2,500 and ca. 3,500 m for the kerogen Type II "Cold" scenario (Figure 49,) with the exception of the Osprey, with only immature strata. Similarly, the Kerogen Type II "Hot" scenario (Figure 50), kerogen Type III "Cold" scenario (Figure 51) and kerogen Type III "Hot" scenario (Figure 52) show a similar pattern (see Tables 9 -12 in appendix C) for time-depth pairs of the different Schnecke plots.

Figure 54 shows a comparison between the "Cold" and "Hot" scenarios for the Sockeye B-10 (kerogen Type II). The burial depth for both scenarios is identical and the differences are related to the different heat flow histories. The start of oil window appears ca. 6 Ma earlier and ca. 8 Ma earlier for gas window conditions in the "Hot" scenario. Resulting from the higher maturation at earlier time, the tops of the oil and gas window conditions are currently present in shallower depths. In addition, overmature conditions occur in thicker parts of the strata.

Related to the higher level of maturation, the depth range, where oil window conditions are present, is smaller in the "Hot" scenario, because the lower parts of these strata are already in the gas window. The pattern described above is also present for the other offshore wells (kerogen Type II, Figures 49 and 50 and kerogen Type III, Figures 51 and 52).

Figure 55 compares maturation modeled in the Sockeye B-10 for the “Hot’ scenario related to the different types of kerogen (II and III). The geochemical parameter (e.g. Hydrogen Index) of a kerogen Type III favors the generation of gas instead of oil. In addition the activation energies for cracking chemical bonds in a Type III kerogen are higher in comparison with Type II kerogen (Tissot and Welte, 1978). Therefore, the base of the gas window for Sockeye B-10 is present at a greater depth for kerogen Type III; whereas at the same depth the sediments are already overmature for kerogen Type II. The same trend can be recognized for the Murrelet K-15 and Harlequin wells for the “Hot” scenario and the Sockeye B-10 well for the “Cold” scenario. These three wells are the only ones which encounter overmature units.

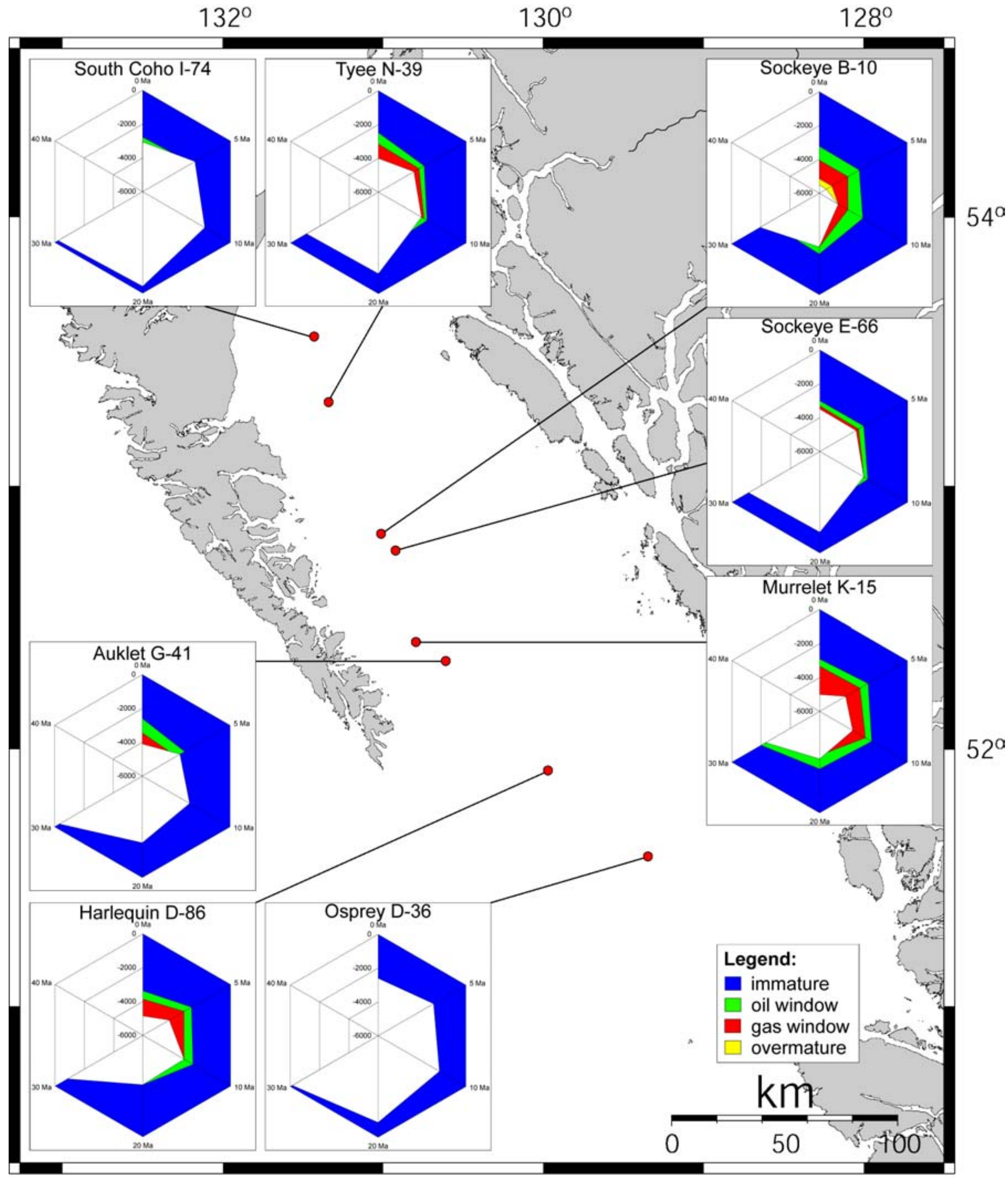

Figure 49. Comparative depth plots of oil and gas zones for offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type II kerogen "Cold" Scenario.

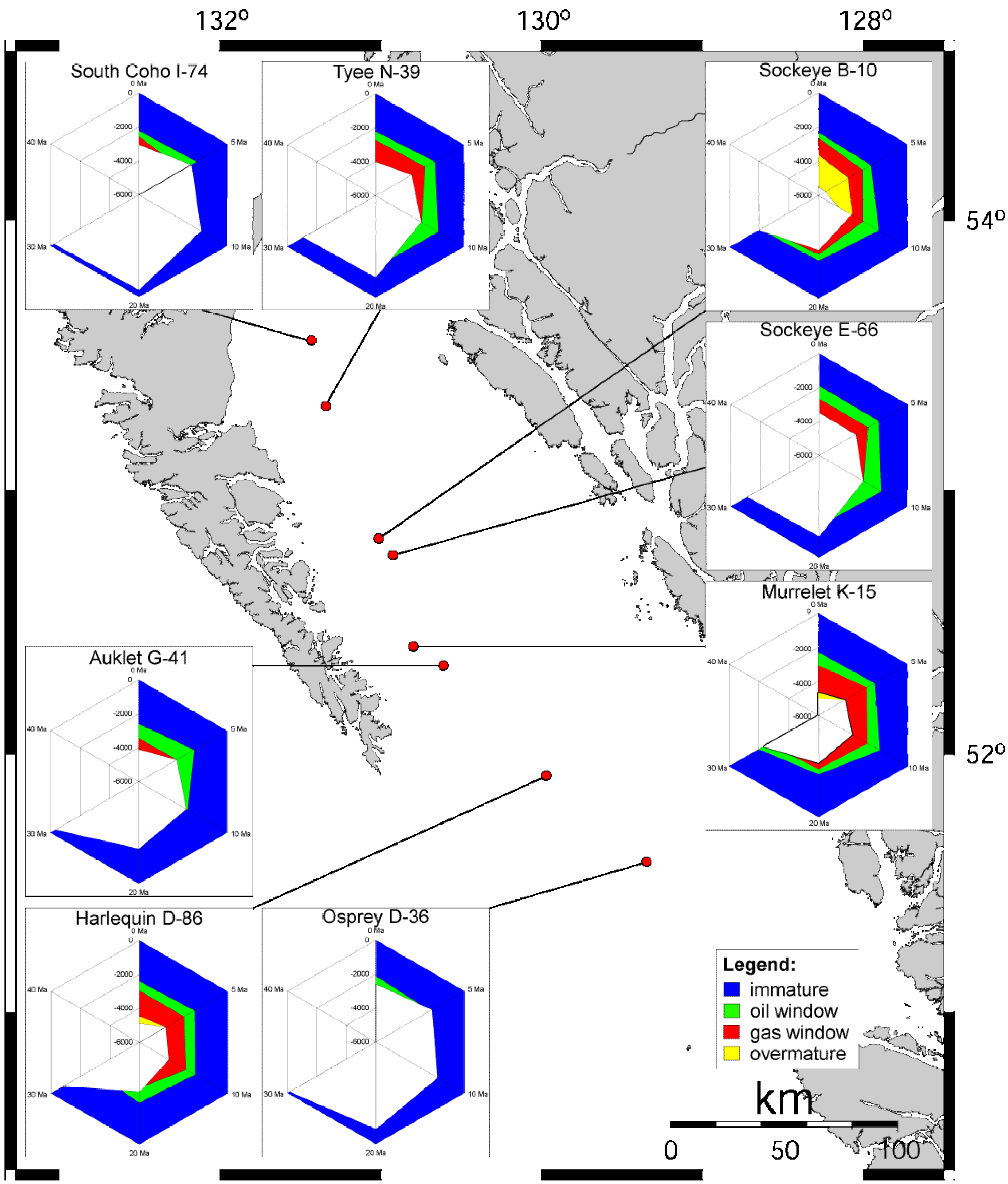

Figure 50. Comparative depth plots of oil and gas zones for offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type II kerogen "Hot" Scenario.

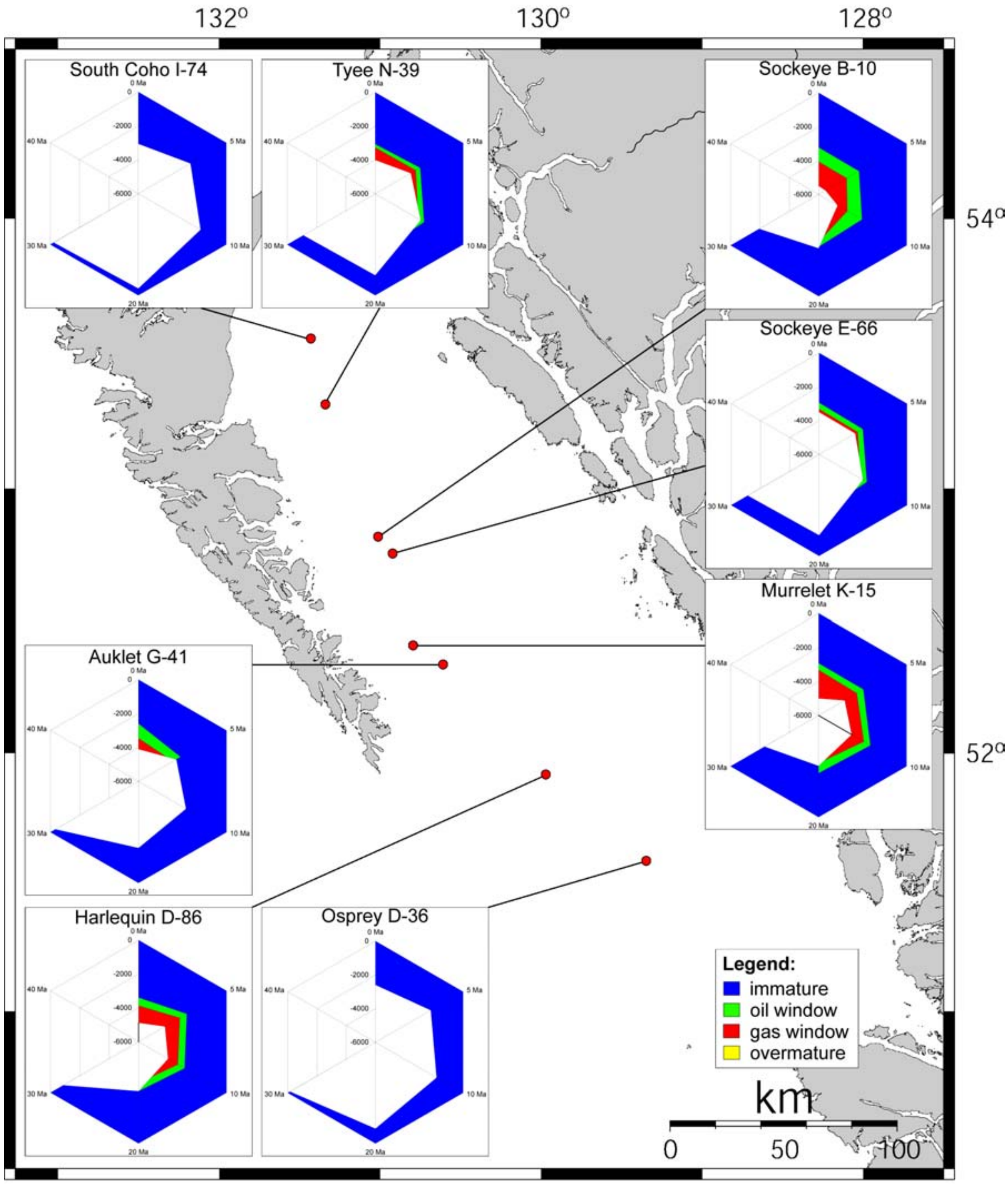

Figure 51. Comparative depth plots of oil and gas zones for offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type III kerogen "Cold" Scenario

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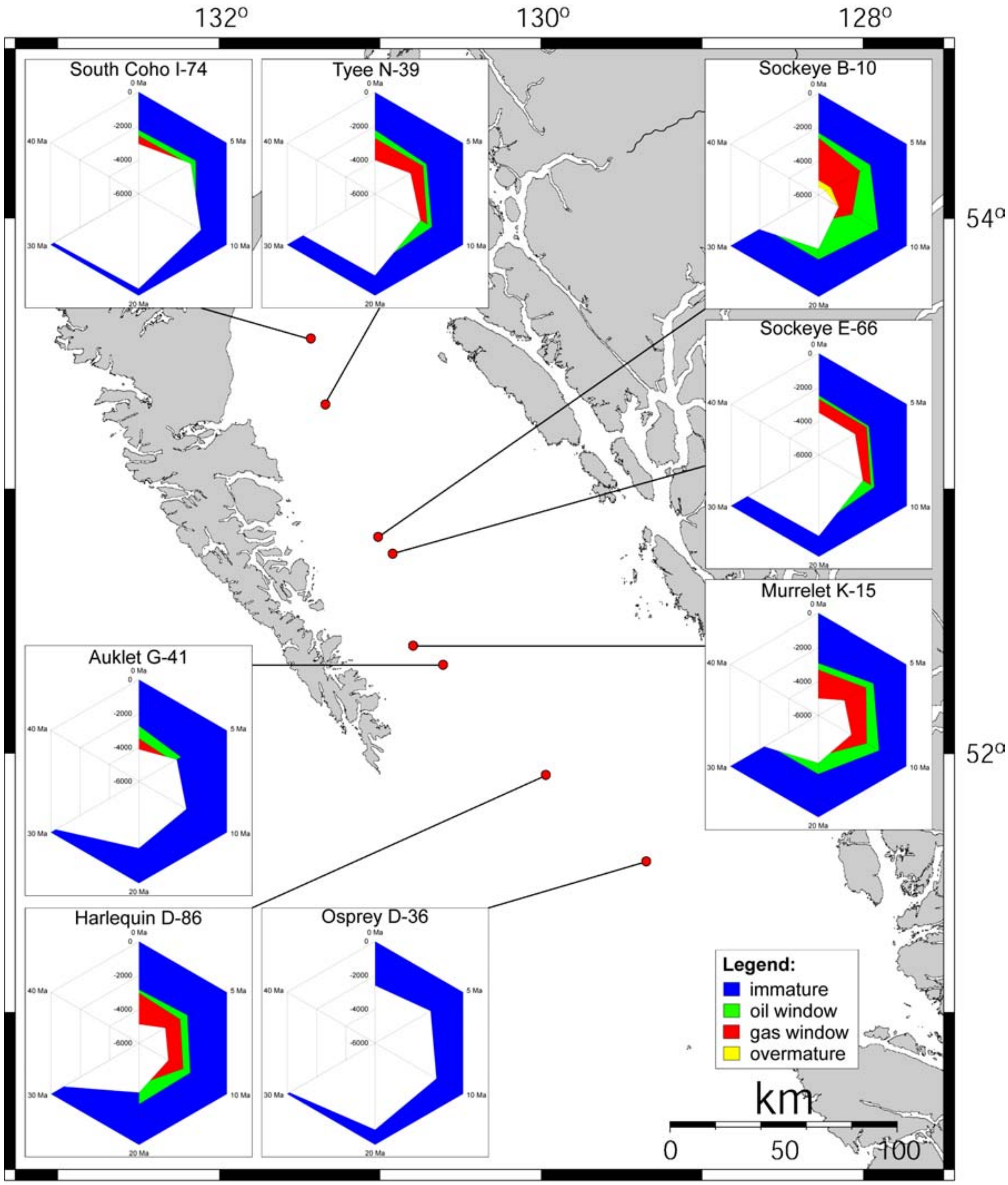


Figure 52. Comparative depth plots of oil and gas zones for offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type III kerogen "Hot" Scenario

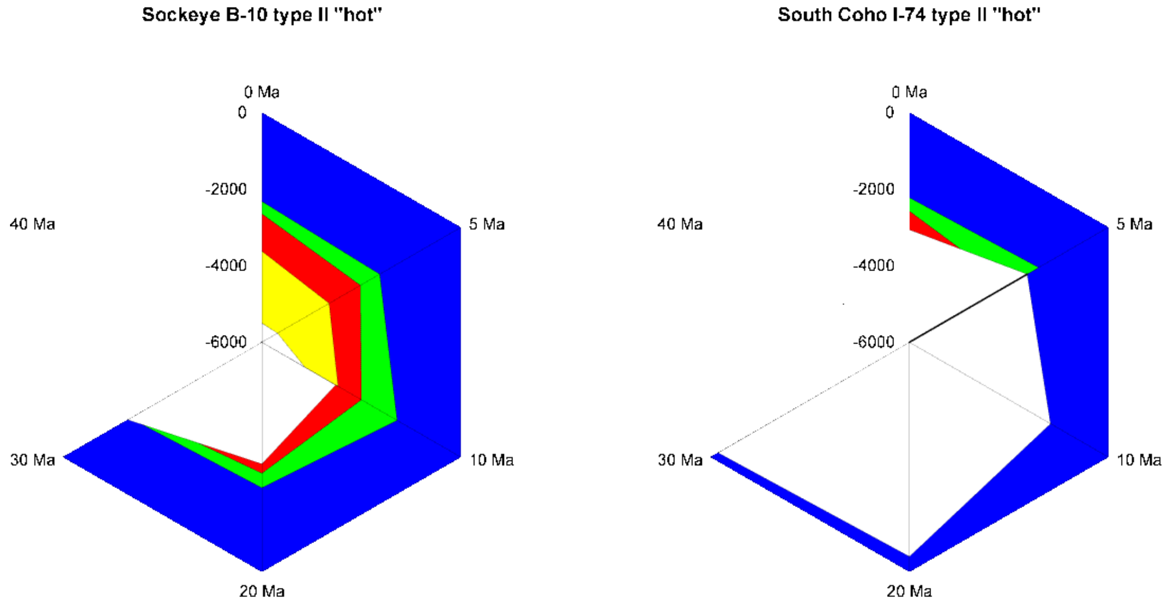


Figure 53. Comparison of models calculated for Sockeye B-10 and South Coho (both kerogen Type II and "Hot" scenario) illustrating differences in total depth (TD) and uniform depths for tops of oil (green) and gas window (red) conditions; computed TD Sockeye B-10 5500 m, computed TD South Coho 3060 m.

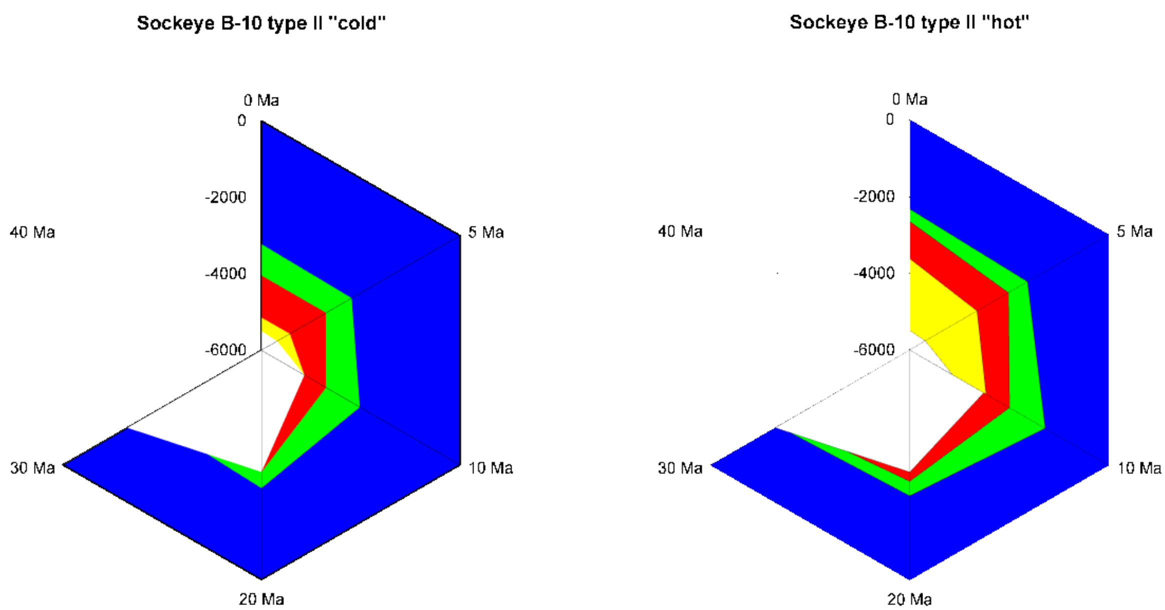
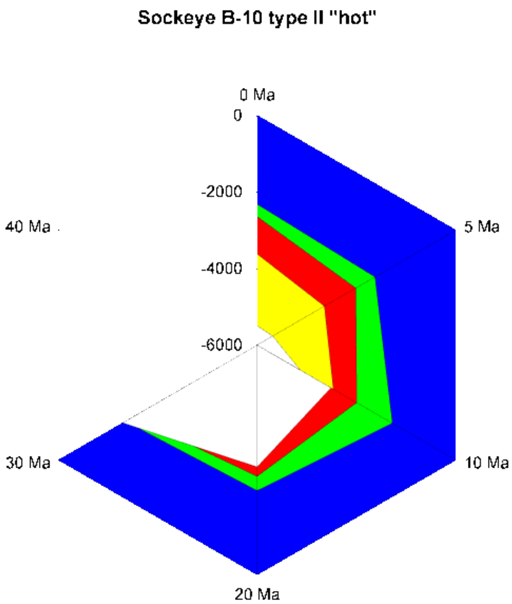


Figure 54. Comparison of models calculated for Sockeye B-10 "Cold" scenario and Sockeye B-10 "Hot" scenario (both kerogen Type II) illustrating differences in depth, timing and presence of immature strata (blue), oil (green) and gas window (red) conditions and overmature strata (yellow) due to different heat flow histories.



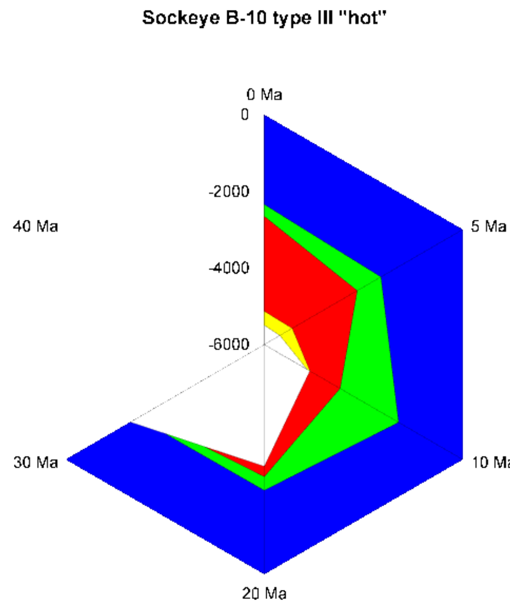


Figure 55. Comparison of models calculated for Sockeye B-10 kerogen Type II and Sockeye B-10 kerogen Type III (both "Hot" scenario) illustrating differences in depth, timing and presence of immature strata (blue), oil (green) and gas window (red) conditions and overmature strata (yellow) due to different kerogen type.

9. Conclusions

Our 1D thermal models fit vitrinite reflectance data measured in the offshore wells and heat values measured in surficial sediments (Lewis et al., 1991a) using a moderate heat flow (100 mW/m^2) during rifting which then decays exponentially. As a result sediments experience warm conditions over a longer time and are predicted to be more mature than previously modeled. In contrast, Hannigan et al. (2001) used a very high initial heat flow which decayed rapidly and stayed fairly cool to match slightly cooler heat flow values measured in the wells.

In our models only the heat flow within the last ~10 Ma is important for the maturation of Cenozoic sediments; older thermal events postulated to occur at 80 Ma and 180 Ma have negligible effects on maturation of Cenozoic sediments.

Paleo-heat flow seems to increase from north to south. In northern Hecate Strait (South Coho, and Tyee wells) a good calibration was achieved to available data using a cold heat flow scenario. In southern Hecate Strait a good calibration was achieved using the hot scenario (Murrelet and Auklet wells), but in Queen Charlotte Sound a hot heat flow scenario underestimates the vitrinite reflectance data (Osprey well).

We can exclude large areas of Cenozoic sediments in Hecate Strait and Queen Charlotte Sound (Figure 56) as non-hydrocarbon generating by an initial mapping of hydrocarbon formation from Cenozoic sources. Extensive generation of oil and gas lies in a fairway approximately 75 km wide and 380 km long that extends northwest to southeast roughly parallel to the axis of the basin on its western side. This is consistent with other reports (e.g., Hannigan et al. 2001).

The Neogene-age areas expected to be most productive in forming oil and gas correspond to an approximate area of 23,000 km^2 (Table 2); in other words ca. 36 % of the basin holds promise for the formation of Cenozoic-sourced hydrocarbons. We also suggest that the Neogene source rocks of interest comprise ca. 38 % of the offshore areas in question.

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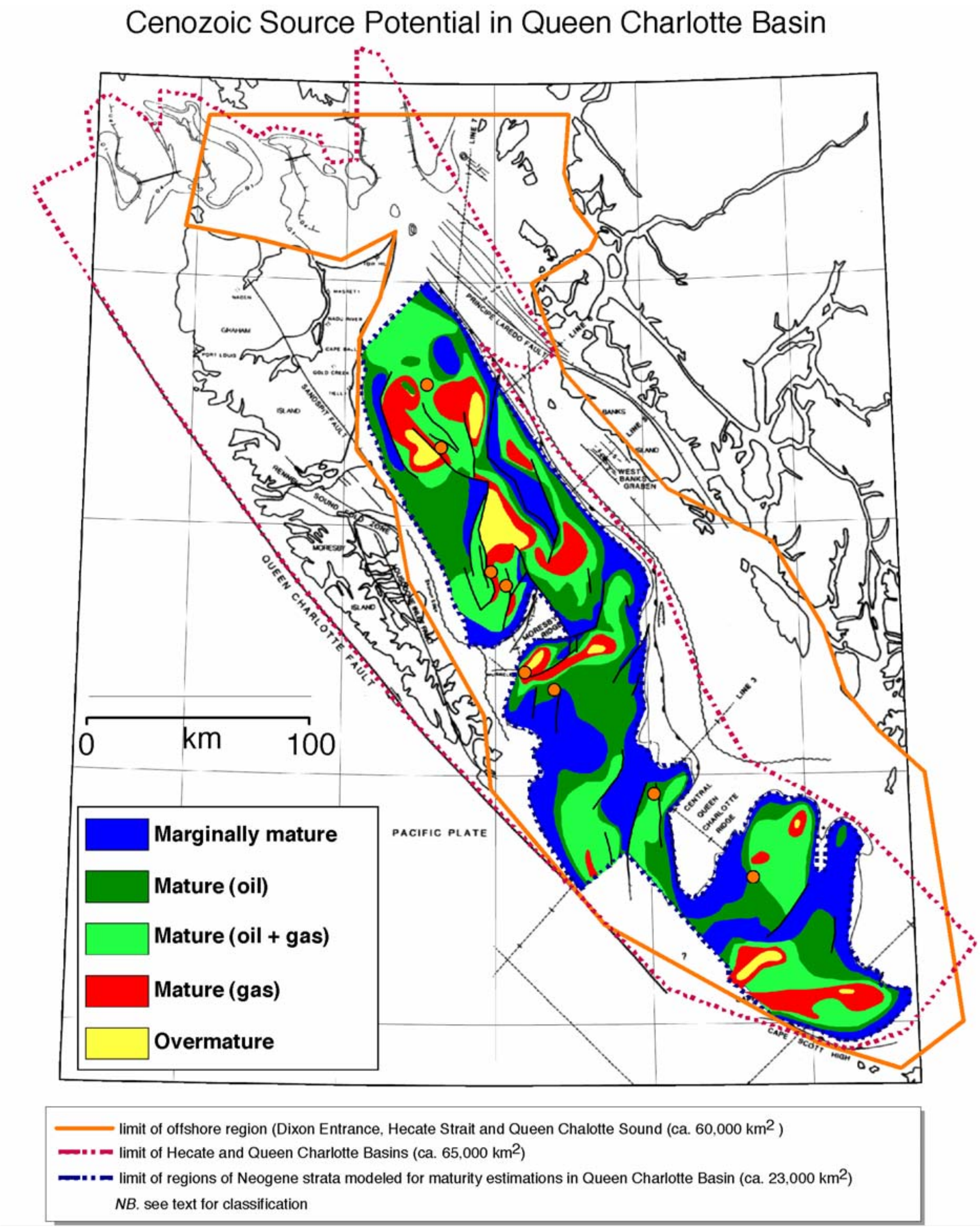

Figure 56. Map of Queen Charlotte Basin region showing the present day maturity zones of the Neogene sediment package and the outlines of the offshore region and the Hecate + Queen Charlotte Basin. The structural information is from Rohr and Dietrich (1992).

10. Outlook for Phase II

Although sufficient well, seismic data and outcrop information allow us to make a reasonable initial assessment of conditions for petroleum formation in the Cenozoic Queen Charlotte Basin, more robust, complete and refined models are possible.

Our 1D models could be improved by a more detailed biostratigraphy that studies of pollen, ichthyoliths, foraminifers in Cenozoic and Mesozoic strata would provide. Of particular interest are better dates on initiation of rifting, deposition of potential source, reservoir, and cap rocks. Only the incorporation of such additional information will allow definition of more detailed burial histories.

In Phase I of the project, no detailed predictions regarding the Mesozoic units are made. This will be attempted in Phase II, recognizing however the large uncertainties in the geophysical and geologic data. In general, sediments deeper than 4,800 m today are likely to be overmature, but nevertheless these units have passed through the oil and gas window during burial and generated hydrocarbons. A complete treatment of the QCB and the Hecate Basin therefore requires careful consideration of these Mesozoic source rocks.

It is also important to note that our Phase I assessments did not address the migration or trapping histories in the QCB, and thus makes no predictions as to potential reservoir locations, frequency or sizes. In Phase II we will construct 2D models based on our 1D models, which will incorporate migration and trapping histories using Temis 2D software (provided by IFP/ Beicip-Franlab, France). Refined interpretation of the seismic reflection data and age assignment to seismic reflectors will be necessary to define additional marker horizons to improve 2D basin models.

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A. Appendix A

Figures A1-A4 show six of the eight multi-channel seismic reflection data acquired by the Geological Survey of Canada (GSC) in 1988. Figure 9 (above) shows line locations. An industry standard ship used a 104 liter (6358 in^3) airgun array shot every 45 m to a 240 channel, 3600 m long streamer resulting in 40-fold data (Rohr and Dietrich, 1990).

The survey and processing procedures were designed to image sedimentary structures as well as lower crustal structure down to Moho. All migrated sections are plotted at the same compressed scale. Every fifth trace is shown, truncated at 5s two way travel time (twt). Uninterpreted full-scale sections are available (Rohr and Dietrich, 1990).

Interpretations of the Miocene-Pliocene reflector, volcanic flows, basement and major faults are shown in Figures T4-T9. These interpretations are largely based on more detailed interpretations in Rohr and Dietrich (1992); more recent work suggests that the Miocene-Pliocene reflector may be lower Pliocene in age (Dietrich, 1995). The eight Shell Anglo offshore wells are superimposed on the data and ties to other lines are marked.

Captions for the Pullout figures A1 – A4.

Figure A1. Line 88-01 extends from the southern end of Hecate Strait through Queen Charlotte Sound almost to northern Vancouver Island.

The upper section a) is the western half of the line; shotpoint (SP) 32700 is marked on both a) and b). It images a series of extensional half-grabens and grabens separated by basement highs overlain by 0.5-1.0 s of flat-lying upper Miocene to Pliocene sediments. Sedimentary reflectors are generally sub-parallel and laterally variable in amplitude (e.g., SP 33150-33450, SP 31100 - 31650). In half-grabens reflectors diverge towards the faults indicating that deposition occurred during extension. Sub-basins drilled by the wells show most divergence in the lower Miocene; small offset faults cut the lower Miocene sediments. Some faults appear to be listric continuing into basement. Both the Osprey and the Harlequin wells stopped drilling in basalt flows; they correlate to a package of bright reflections. Occasional very bright events higher up in the sedimentary section may indicate the presence of isolated basalt flows (~SP 31075; see also Sutherland and Rohr, 2001). Layering in basement could be reflections from Triassic volcanic or Cretaceous rocks (SP 34350-34700). In southernmost Queen Charlotte Sound reflectors are difficult to interpret; they are discontinuous, variable in amplitude and seem to blend smoothly into basement or possible basalt flows.

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Figure A2a) Line 88-03 spans the continental shelf out to the oceanic crust in the west.

The Queen Charlotte Fault (QCF) separates the Pacific from the North American plate; it separates very different reflection packages. Nearby shelf sediments (SP 1200-1700) are remarkably undeformed given their proximity to the plate boundary. West of the Harlequin well a basement high impedes seismostratigraphic correlation.

Figure A2b) Line 88-04 is oriented sub-parallel to and in the western side of Hecate Strait.

It ties four wells and four seismic reflection lines. The extensional basin fill is lower to upper Miocene. In Hecate Strait (Figures A3 and A4) sub-basins are smaller; they were compressed mostly in the Pliocene with local compression in the late Miocene and some deformation possibly continuing (Figure A4). Between SP 1550 and 2000 the ship steamed sub-parallel to a basement-cutting fault and recorded basement reflections from both sides of the fault. This obscures interpretation of the seismic data in the vicinity of the Sockeye wells.

Figure A3a) Line 88-05 crosses several sub-basins in Hecate Strait perpendicular to the strike of the QCB.

Uplift of basement increases to the west, towards the Queen Charlotte Islands; basement is involved in deformation. The Sockeye B-10 well drilled an anticline which has been eroded at the seafloor down into the Miocene sediments. High amplitude layered sequences exist at the base of some sub-basins similar to those in Queen Charlotte Sound implying the presence of basaltic flows (SP 850 – 950). This high reflectivity masks underlying sequences, possible Mesozoic sediments.

Figure A3b) Line 88-06 crosses Hecate Strait perpendicular to the strike of the QCB.

A vertical strike-slip fault separates very different reflection patterns on either side of the fault (SP 420). Seismostratigraphic correlation across the fault is therefore difficult. Upper Miocene deformation compressed the sub-basin between shot points 675 and 925. At SP 1200 basement is involved in inversion of a similar age. Bright isolated segments of reflectors within basement are puzzling; they might be from fault traces or layering in Mesozoic sediments. At SP 1870 the Principe Laredo Fault (PLF) is thought to separate Wrangellia from the Alexander terrane.

Figure A4. Line 88-07 extends from the northern end of Hecate Strait into Dixon Entrance, crossing the Principe Laredo Fault (PLF) into the Alexander terrane.

The upper section a) shows the southern half of the line; shotpoint 1700 is marked on both a) and b). The Miocene-Pliocene reflector is an erosional unconformity in places (SP 975-1070). Micro-seismicity is common in the area south of the PLF; a magnitude 5.3 earthquake occurred beneath a recently uplifted sub-basin (SP 1350-1700).

B. Appendix B

Table Captions

Table B1. Maturity modelling output data "Cold" Type II kerogen

Table B2. Maturity modelling output data "Cold" Type III kerogen

Table B3. Maturity modelling output data "Hot" Type II kerogen

Table B4. Maturity modelling output data "Hot" Type III kerogen

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"cold" scenario type II	Auklet G-41		Harlequin D-86		Murrelet K-15		Osprey D-36		Sockeye B-10		Sockeye E-66		South Coho I-74		Tyee N-39	
	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth
	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]
Start Oil Window	5	3100	19	3080	33	2520			23	2550	13	2510	3	2640	13	9
StartGas Window	2	3660	16	3570	18	3400			18	3070	9	3170			9	3060
Start Overmature									11	4460						
Top Oil Window	30		30		30	2000	30		30		30		30		30	
Base Oil Window	30		30		30	2300	30		30		30		30		30	
Top Gas Window	30		30		30	2300	30		30		30		30		30	
Base Gas Window	30		30		30		30		30		30		30		30	
Top Overmature	30		30		30		30		30		30		30		30	
Base Model	30	340	30	870	30	2320	30	150	30	1950	30	1130	30	230	30	1090
Top Oil Window	20		20		20	2600	20		20	2400	20		20		20	
Base Oil Window	20		20		20	3000	20		20	2800	20		20		20	
Top Gas Window	20		20		20	3000	20		20	2800	20		20		20	
Base Gas Window	20		20		20		20		20		20		20		20	
Top Overmature	20		20		20		20		20		20		20		20	
Base Model	20	2060	20	3080	20	3190	20	880	20	2820	20	1220	20	400	20	1180
Top Oil Window	10		10	2575	10	2450	10		10	3025	10	2725	10		10	2675
Base Oil Window	10		10	3175	10	2875	10		10	4050	10	3000	10		10	2890
Top Gas Window	10		10	3175	10	2875	10		10	4050	10	3000	10		10	2890
Base Gas Window	10		10		10		10		10	4600	10		10		10	
Top Overmature	10		10		10		10		10	4600	10		10		10	
Base Model	10	2760	10	3990	10	3740	10	1810	10	4710	10	3000	10	1750	10	3060
Top Oil Window	5		5	2675	5	2700	5		5	3275	5	3000	5		5	2875
Base Oil Window	5		5	3175	5	3250	5		5	4050	5	3350	5		5	3225
Top Gas Window	5		5		5	3250	5		5	4050	5	3350	5		5	3225
Base Gas Window	5		5		5		5		5	5150	5		5		5	
Top Overmature	5		5		5		5		5	5150	5		5		5	
Base Model	5	3420	5	4200	5	4220	5	2210	5	5530	5	3530	5	2440	5	3570
Top Oil Window	0	2600	0	3375	0	2900	0		0	3225	0	3000	0		0	2480
Base Oil Window	0	3450	0	3850	0	3325	0		0	4050	0	3300	0		0	3150
Top Gas Window	0	3450	0		0	3325	0		0	4050	0	3300	0		0	3150
Base Gas Window	0		0		0		0		0	5100	0		0		0	
Top Overmature	0		0		0		0		0	5100	0		0		0	
Base Model	0	4100	0	4880	0	5000	0	2600	0	5500	0	3500	0	3060	0	4000

"cold" scenario type III	Auklet G-41		Harlequin D-86		Murrelet K-15		Osprey D-36		Sockeye B-10		Sockeye E-66		South Coho I-74		Tyee N-39	
	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth
	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]
Start Oil Window	5	3130	20	3090	20	2590			20	2910	13	2500			13	2400
StartGas Window	2	3650	16	3570	16	3020			16	3210	8	3170			8	3060
Start Overmature																
Top Oil Window	30		30		30		30		30		30		30		30	
Base Oil Window	30		30		30		30		30		30		30		30	
Top Gas Window	30		30		30		30		30		30		30		30	
Base Gas Window	30		30		30		30		30		30		30		30	
Top Overmature	30		30		30		30		30		30		30		30	
Base Model	30	340	30	870	30	2320	30	150	30	1950	30	1130	30	230	30	1090
Top Oil Window	20		20	3080	20	2590	20		20	2900	20		20		20	
Base Oil Window	20		20		20		20		20		20		20		20	
Top Gas Window	20		20		20		20		20		20		20		20	
Base Gas Window	20		20		20		20		20		20		20		20	
Top Overmature	20		20		20		20		20		20		20		20	
Base Model	20	2060	20	3080	20	3190	20	880	20	2910	20	1220	20	400	20	1180
Top Oil Window	10		10	2870	10	2470	10		10	3050	10	2740	10		10	2660
Base Oil Window	10		10	3320	10	2920	10		10	4050	10		10		10	
Top Gas Window	10		10	3320	10	2920	10		10	4050	10		10		10	
Base Gas Window	10		10		10		10		10		10		10		10	
Top Overmature	10		10		10		10		10		10		10		10	
Base Model	10	2760	10	3990	10	3740	10	1810	10	4710	10	3000	10	1750	10	2890
Top Oil Window	5	3130	5	2710	5	2940	5		5	3250	5	3010	5		5	2930
Base Oil Window	5		5	3190	5	3390	5		5	4090	5	3360	5		5	3230
Top Gas Window	5		5	3190	5	3390	5		5	4090	5	3360	5		5	3230
Base Gas Window	5		5		5		5		5		5		5		5	
Top Overmature	5		5		5		5		5		5		5		5	
Base Model	5	3420	5	4200	5	4220	5	2210	5	5530	5	3530	5	2440	5	3570
Top Oil Window	0	2600	0	3390	0	2920	0		0	3220	0	2980	0		0	3060
Base Oil Window	0	3460	0	3870	0	3310	0		0	4060	0	3320	0		0	3270
Top Gas Window	0	3460	0	3870	0	3310	0		0	4060	0	3320	0		0	3270
Base Gas Window	0		0		0		0		0		0		0		0	
Top Overmature	0		0		0		0		0		0		0		0	
Base Model	0	4100	0	4880	0	5000	0	2600	0	5500	0	3500	0	3060	0	4000

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"hot" scenario type II	Auklet G-41		Harlequin D-86		Murrelet K-15		Osprey D-36		Sockeye B-10		Sockeye E-66		South Coho I-74		Tyee N-39	
	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth
	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]
Start Oil Window	11	2660	21	2750	33	2520	3	2330	29	2030	13	1810	5	2100	13	1760
StartGas Window	4	3620	18	3320	22	2650			26	2250	9	2460	2	2530	9	2430
Start Overmature					4	4250			11	3700						
Top Oil Window	30		30		30	2000	30		30		30		30		30	
Base Oil Window	30		30		30	2300	30		30		30		30		30	
Top Gas Window	30		30		30	2300	30		30		30		30		30	
Base Gas Window	30		30		30		30		30		30		30		30	
Top Overmature	30		30		30		30		30		30		30		30	
Base Model	30	340	30	870	30	2320	30	150	30	1950	30	1130	30	230	30	1090
Top Oil Window	20		20	2450	20	2525	20		20	2200	20		20		20	
Base Oil Window	20		20	3000	20	2825	20		20	2575	20		20		20	
Top Gas Window	20		20	3000	20	2825	20		20	2575	20		20		20	
Base Gas Window	20		20		20		20		20		20		20		20	
Top Overmature	20		20		20		20		20		20		20		20	
Base Model	20	2060	20	3080	20	3190	20	880	20	2820	20	1220	20	400	20	1180
Top Oil Window	10	2350	10	2225	10	1875	10		10	1925	10	1775	10		10	1725
Base Oil Window	10	2750	10	2825	10	2700	10		10	3000	10	2975	10		10	2900
Top Gas Window	10	2750	10	2825	10	2700	10		10	3000	10	2975	10		10	2900
Base Gas Window	10		10		10		10		10	3775	10		10		10	
Top Overmature	10		10		10		10		10	3775	10		10		10	
Base Model	10	2760	10	3990	10	3740	10	1810	10	4710	10	3000	10	1750	10	2900
Top Oil Window	5	2250	5	2275	5	2250	5		5	2450	5	1950	5	2100	5	1975
Base Oil Window	5	3400	5	2975	5	2750	5		5	3025	5	2700	5	2450	5	2625
Top Gas Window	5	3400	5	2975	5	2750	5		5	3025	5	2700	5	2450	5	2625
Base Gas Window	5		5		5		5		5	3975	5		5		5	
Top Overmature	5		5		5		5		5	3975	5		5		5	
Base Model	5	3420	5	4200	5	4220	5	2210	5	5530	5	3530	5	2500	5	3570
Top Oil Window	0	2600	0	2400	0	2300	0	2125	0	2325	0	1900	0	2225	0	2225
Base Oil Window	0	3450	0	2950	0	3075	0	2600	0	2650	0	2675	0	2575	0	2725
Top Gas Window	0	3450	0	2950	0	3075	0	2600	0	2650	0	2675	0	2575	0	2725
Base Gas Window	0		0	4450	0	4675	0		0	3625	0		0		0	
Top Overmature	0		0	4450	0	4675	0		0	3625	0		0		0	
Base Model	0	4100	0	4880	0	5000	0	2600	0	5500	0	3500	0	3060	0	4000

"hot" scenario type III	Auklet G-41		Harlequin D-86		Murrelet K-15		Osprey D-36		Sockeye B-10		Sockeye E-66		South Coho I-74		Tyee N-39	
	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth	Age	Depth
	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]	[Ma]	[m]
Start Oil Window	5	3130	20	2400	23	2530			27	2180	13	1810	6	2100	13	1760
StartGas Window	2	3650	16	2880	21	2760			26	2310	9	2460	2	2530	9	2430
Start Overmature			2	4510					11	4450						
Top Oil Window	30		30		30		30		30		30		30		30	
Base Oil Window	30		30		30		30		30		30		30		30	
Top Gas Window	30		30		30		30		30		30		30		30	
Base Gas Window	30		30		30		30		30		30		30		30	
Top Overmature	30		30		30		30		30		30		30		30	
Base Model	30	340	30	870	30	2320	30	150	30	1950	30	1130	30	230	30	1090
Top Oil Window	20		20	2400	20	2540	20		20	2190	20		20		20	
Base Oil Window	20		20		20	2840	20		20	2560	20		20		20	
Top Gas Window	20		20		20	2840	20		20	2560	20		20		20	
Base Gas Window	20		20		20		20		20		20		20		20	
Top Overmature	20		20		20		20		20		20		20		20	
Base Model	20	2060	20	3080	20	3190	20	880	20	2820	20	1220	20	400	20	1180
Top Oil Window	10		10	2500	10	1860	10		10	1940	10	2220	10		10	2110
Base Oil Window	10		10	2990	10	2700	10		10	3710	10		10		10	
Top Gas Window	10		10	2990	10	2700	10		10	3710	10		10		10	
Base Gas Window	10		10		10		10		10	4620	10		10		10	
Top Overmature	10		10		10		10		10	4620	10		10		10	
Base Model	10	2760	10	3990	10	3740	10	1810	10	4710	10	3000	10	1750	10	2890
Top Oil Window	5	3130	5	2700	5	2240	5		5	2480	5	2590	5	2100	5	2480
Base Oil Window	5		5	3190	5	2750	5		5	3190	5	2730	5		5	2720
Top Gas Window	5		5	3190	5	2750	5		5	3190	5	2730	5		5	2720
Base Gas Window	5		5		5		5		5	5160	5		5		5	
Top Overmature	5		5		5		5		5	5160	5		5		5	
Base Model	5	3420	5	4200	5	4220	5	2210	5	5530	5	3530	5	2440	5	3570
Top Oil Window	0	2720	0	2840	0	2920	0		0	2340	0	2490	0	2240	0	2230
Base Oil Window	0	3470	0	3040	0	3310	0		0	2650	0	2700	0	2580	0	2720
Top Gas Window	0	3470	0	3040	0	3310	0		0	2650	0	2700	0	2580	0	2720
Base Gas Window	0		0		0		0		0	5130	0		0		0	
Top Overmature	0		0		0		0		0	5130	0		0		0	
Base Model	0	4100	0	4880	0	5000	0	2600	0	5500	0	3500	0	3060	0	4000

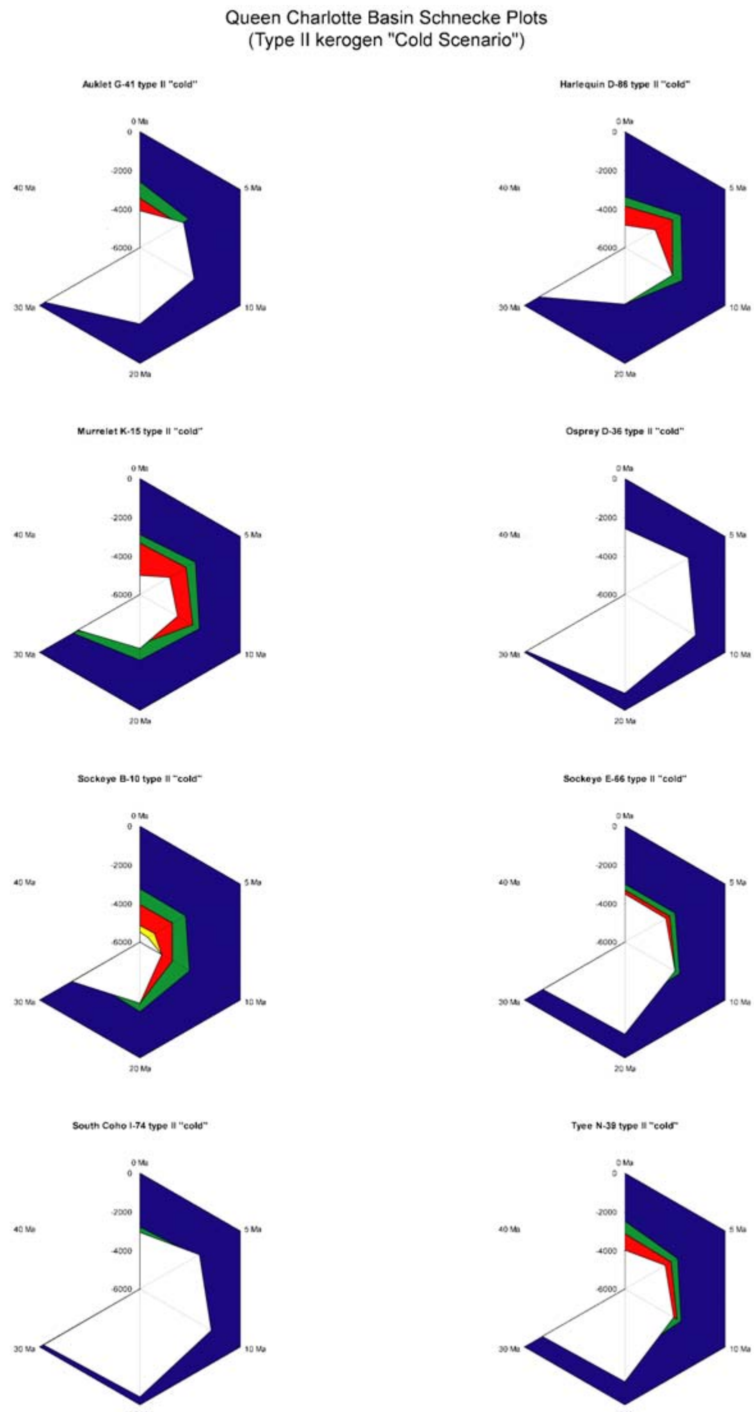

Figure B1. Comparative depth plots of oil and gas zones for 8 offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type II kerogen "Cold" Scenario/

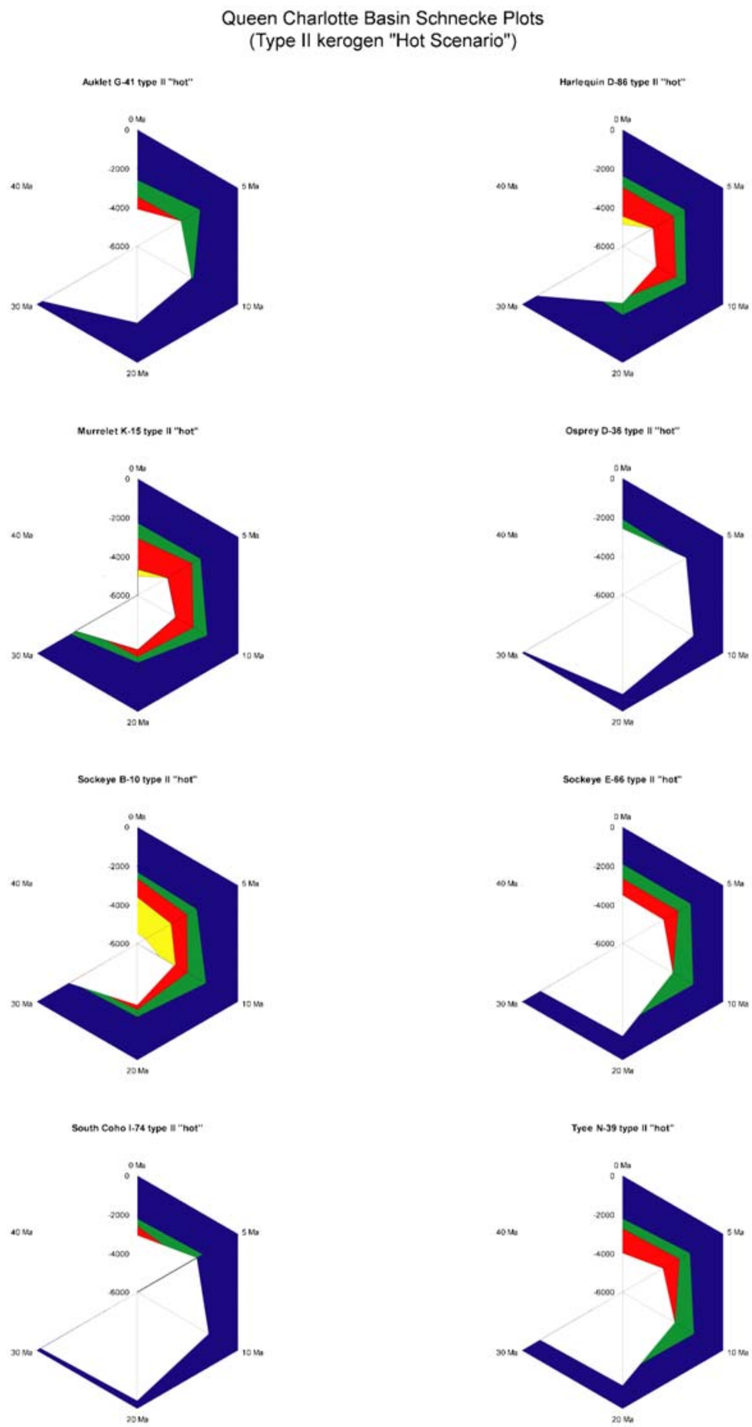

Figure B2. Comparative depth plots of oil and gas zones for 8 offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type II kerogen "Hot" Scenario.

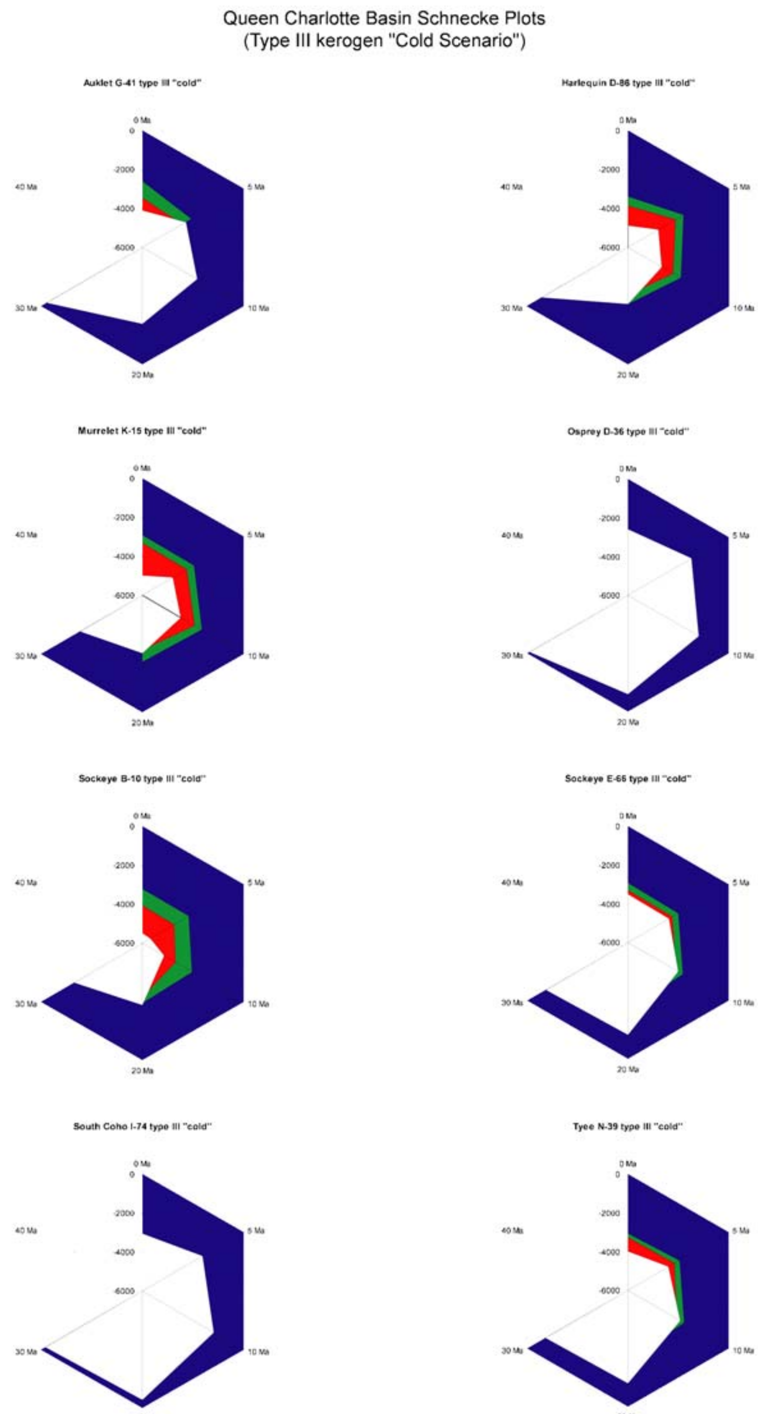

Figure B3. Comparative depth plots of oil and gas zones for 8 offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type III kerogen "Cold" Scenario.

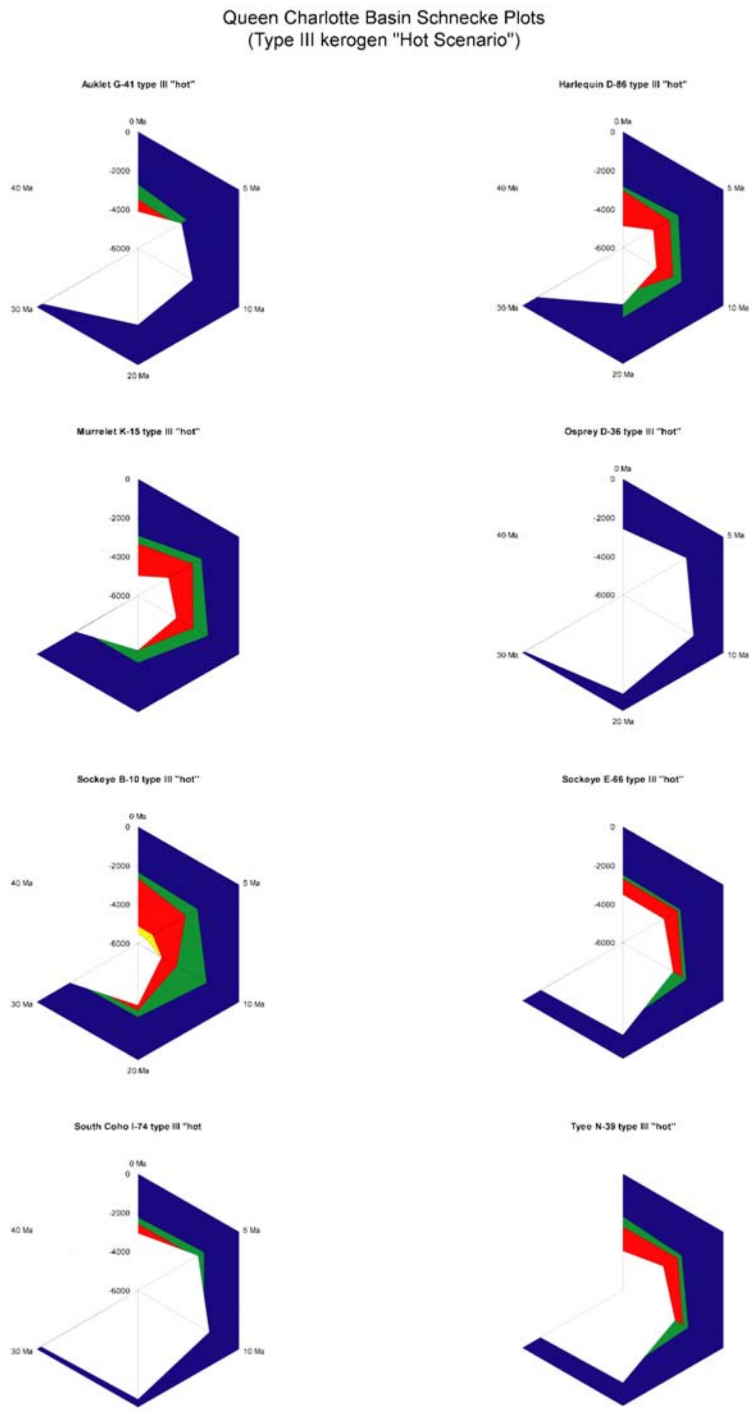

Figure B4. Comparative depth plots of oil and gas zones for 8 offshore QCB wells for various time slices (30 Ma to present), based on modelled data – Type III kerogen "Hot" Scenario

Appendix C. Stratigraphy of Shell Canada Wells in Queen Charlotte Basin

The following is a summary of a basic stratigraphy for the 8 offshore Queen Charlotte Basin (QCB) wells. The information is extracted from the original Shell well history reports, (Shell Canada Ltd., 1968a, b, c, d, e, f, 1969a, b) and augmented by other authors. We believe that significant improvements can be made on the ages and stratigraphic assignments, and that there are some inconsistencies in the interpretation that may require additional work.

Accompanying this summary is Figure C1 showing an along-axis stratigraphic cross-section of the QCB connecting the 8 offshore wells. It was generated largely from the Shell well reports, and hence is subject to considerable revision. As such it represents the view of the basin stratigraphy typically used; some modifications of stratigraphy not included were done in the Murrelet, Harlequin and Osprey wells (Patterson, 1989;White et al., 1994).

C.1 Approach

Data and reports from eight wells drilled in the QCB by Shell Canada Ltd. were reviewed (Coho, Tyee N-39, Sockeye B-10 and E-66, Murrelet K-15, Auklet G-41, Harlequin D-86, and Osprey, D-36); their locations are shown above in Figure C1. These wells were drilled in the late 1960's before the current Federal and Provincial moratoria on offshore hydrocarbon exploration were in place.

In this review, Shell Canada well strata were correlated from approximately north to south (Figure C1) in an order similar to previous work (Shouldice, 1971, 1973; Young, 1981; Bustin, 1997). More emphasis in this work was placed on the interpretation, correlation, and illustration of sequence units within the Shell wells. Higgs (1991) published a similar correlation which stressed mapping syn-rift (Unit I) and post-rift (Unit II) sequences based on sonic logs and tying to outcrops on the Queen Charlotte Islands (QCI). This study provides more detail on the offshore sequences.

The data sources in this report included the archival Shell Canada paleontological and lithological reports on the cuttings and well gamma ray, sonic, spontaneous potential, resistivity, bulk density, and conductivity log data. Microflora and fauna intervals indicated (Figure C1) were colour-coded to the International Stratigraphic Chart standard, were from the original Shell Canada reports, and were not updated to current paleontological zones/standards. To provide a biostratigraphic update, review of the original taxa and microslides would have been necessary (most were not available) or new materials would need to be processed and studied from the well cuttings.

Inherent problems with the Shell Canada well cuttings from the QCB were their poor quality due to the lithified nature of the sediments, a rapid drill penetration rate, and potential down well reworking or spalling. Also, some well log interpretations of coarsening-up sequences could be masked by feldspathic sandstones that have a "shaly" response (e.g. Galloway, 1974; Cant, 1984; Higgs, 1991); therefore, it was important to review and compare all well log data. It was assumed that Shell Canada biostratigraphic studies used last appearance datums to address the down well spalling issue. Higgs (1991) emphasized the importance of comparing outcrop and well data to provide the needed detail to interpret large scale sedimentary features (e.g. hummocky cross-stratification) and dispersed features (e.g. drop stones) seen in outcrops.

The discussion on the offshore wells below includes comparisons and correlations to Higgs' Units I and II (1989 a, b; 1991) and integrates or considers where possible other important published data and results (e.g. *stratigraphy:* Sutherland Brown, 1968; Shouldice, 1971, 1983; Young, 1981; Champigny et al., 1981; Patterson, 1989; Higgs, 1989 a, b; 1991; White 1990, 1991; White et al. 1994); *tectonism, volcanism, and plutonism results:* Young, 1981; Anderson & Greig, 1989; Anderson & Reichenbach, 1989; Hickson, 1991; Hyndman and Hamilton, 1993; Woodsworth, 1991; Rohr et al., 2000); *source rock potential studies*: Vellutini and Bustin, 1991; Bustin, 1997; Hannigan et al., 2001; and *seismic interpretations and results* Rohr & Dietrich, 1991, 1992; Dietrich, 1995;).

C.2 Results of Review of Offshore Shell Canada Wells

C.2 .1 Cenozoic and Mesozoic volcanics and Mesozoic strata

Some of the Hecate Strait wells at their base penetrated Mesozoic or older rocks, showing a linkage to similar rocks on the Queen Charlotte Islands. These rocks included:

1) Mesozoic eruptions in Hecate Strait that recorded Middle Jurassic Yakoun QCI volcanism (Sockeye E-66, base of unit 1; Tyee, unit 1) (Shell Canada, 1968a, c; and
2) late Cretaceous volcanism that overlies or was interbedded with late Cretaceous strata (Sockeye B-10, units 1 to 3; Sockeye E-66, units 2 to 6; Tyee, unit 2) (Shell Canada LTD., 1968a, b, c; Shouldice, 1971; Young, 1981).

A shift to younger volcanic rocks at the base of the wells was found in the southern part of Hecate Strait and Queen Charlotte Sound (Murrelet, unit 2; and Auklet, Harlequin, and Osprey, unit 1) (Shell Canada LTD., 1968d, e, f; Young, 1981). In northern Hecate Strait, volcanics interfingered with or were deposited in Middle to lower Miocene strata; and may be equivalent to the Masset volcanics or possibly older rocks (Coho, units 1, 2; Tyee, units 3, 4) (Shell Canada LTD., 1968a, 1969a; Young, 1981; Hyndman and Hamilton, 1993; Higgs, 1991). Slickensided units (e.g. Tyee, unit 3) (Shell Canada LTD., 1968a) indicate significant faulting just below these volcanics but overlying an unconformity and Late Cretaceous strata. Some of the coarser grained volcanics may be older and reworked having been deposited in lower Miocene strata. Bentonites were common in the south indicating aerial volcanic dispersal within the lower to middle Miocene in Harlequin (units 3 and 4), and Osprey (units 2 and 3). Less common bentonites were within Miocene strata to the north in Sockeye B-10 (unit 6c(Shell Canada LTD., 1968b), and in the south, lower Pliocene in Osprey (unit 5).

C.2 .2 Skonun Formation

Up to about 5 km of marine and nonmarine siliclastics of the Skonun formation, and a small component of Pleistocene to Recent sediments overlie the volcanics and Mesozoic strata in the QCB Shell wells (Shouldice, 1971, 1973). The type section (about 470 feet exposed) of the Skonun formation at Skonun Point on the QCI was described by Mackenzie (1916) and Sutherland Brown (1968). Because the exposure was small in comparison to the onshore boreholes, Sutherland Brown correlated and recommended that the boreholes be used as a standard. Higgs (1991): 1) redefined the QCB basin fill to include the Masset volcanics in the lower basin fill (based on partial Skonun-Masset age equivalence and probable interfingering) 2) suggested that the western edge of the QCB extends to the Queen Charlotte Fault; 3) interpreted Skonun Formation facies based on exposures and borehole cores on the QCI, and two cores of the Shell Canada wells in Queen Charlotte Sound (Harlequin D-86 and Osprey D-36); and 4) discussed potential reservoirs and exploration targets. The Skonun included alluvial fan, fan delta, and fluvial facies (Higgs' Unit II, upper), overlying allogenic regressive cycles of coarsening-up shale/sand/conglomerate sequences (Higgs' Unit II, lower), and was underlain by Masset volcanics and intercalated sediments (Higgs' Unit I). Higgs postulated that syn-rift Unit I resulted from extensional block faulting where sedimentation and volcanism took place in grabens and half-grabens which are seen on seismic profiles (Rohr and Dietrich, 1992). This was followed by regional subsidence and deposition of post-rift Unit II (Higgs, 1991) from the Miocene through the Quaternary. Tidal sedimentary structures in Unit II shelf deposits were thought to correlate to uplift of the QCI which would channel strong tidal currents. Unfortunately timing of uplift on the QCI is largely unknown, but is probably most recently tied to transpression on the Pacific-North American plate boundary (Yorath and Hyndman, 1983; Hyndman and Hamilton, 1991; Rohr & Dietrich, 1992; Rohr et al., 2000) which began at 5 Ma (Atwater and Stock, 1998).

The lower Miocene strata in northern Hecate Strait consisted of interfingered volcanics and sediments (Shell Canada LTD.; 1968a, 1969a) which are probably equivalent to Higgs' (1991) Unit I in the Coho (Figure C1, units 1, 2) and Tyee (units 3 to 5) wells. Overlying strata in Coho and Tyee included interbedded clastics, coals and carbonaceous materials typical of Higgs' Unit II and a delta-plain facies (Higgs, 1991). The climate was warm temperate (Shell Canada LTD., 1968a, 1969a) and the environment was changing as indicated by the interbedded nature of the sediments and varying marine and non-marine conditions also seen in outcrop and boreholes on Graham Island (Martin and Rouse, 1966; Sutherland Brown, 1968; Higgs, 1991). Some of this coal production may have been associated with a general global warming trend and an early to middle Miocene transgression (Prothero and Berggren, 1992; Shell Canada LTD. 1968a, 1969a).

In the Tyee well (Shell Canada LTD. 1968a) there was a more basinal trend indicated by increased calcareous intervals, fining-up sequence sets (Fig C1, units 8, 10-12), and a strong marine indicator in unit 9 with shells and fish teeth that may be a lag or turbidite. The upper Miocene/lower Pliocene boundary at about 6200 feet in the Tyee well was near the transition from maximum regression (units 6b top, 6c and 7) to the start of regional subsidence (unit 8) which continued through unit 12. Near this boundary there is a change from the warm and moist temperate lower to middle Miocene flora (e.g. *Metasequoia* flora) to the cool and drier temperate upper Pliocene conifer flora (Martin & Rouse, 1966; Shouldice, 1971; Hopkins, 1975, 1981; White et al., 1994). This cooling is an indication of the commencement of regional glaciation in the late Pliocene. Overlying sediments (units 13, 14, 15 base) contain an unconsolidated sand of uncertain origin that is correlative with Coho unit 11 and possibly part of the Pliocene sand units in onshore Cape Ball, Tlell and Gold Creek boreholes (see Sutherland Brown, 1968).

In Sockeye B-10 (Shell Canada LTD., 1968b) Higgs' Unit I (1991) containing coarse-grained volcanics is apparently absent because the volcanics (Figure C1, unit 3) dated by Young (1981) indicated a Late Cretaceous age (84$\pm$10 Ma) and the overlying strata included the coaly and interbedded clastic sequences (units 4 to 6d) typical of Higgs' lower Unit II (1991). Bentonites were observed in unit 6c and are most likely a signature of Cenozoic volcanic events, similar to the Masset. The interbedded clastics/coals/carbonaceous materials in Sockeye B-10 have an increased thickness in comparison to the other wells perhaps representing more time and older strata near the base. Paleontological evidence was sparse and uncertain in this interval indicating undiagnostic Cenozoic and no Upper Cretaceous taxa. The presence of glauconite and pyrite indicate quiet deposition in a marine basinal environment (units 6b to 6d); this differs from Shouldice's 1971 interpretation of nonmarine conditions. The basin was still shallow enough to have interbedded sediments and changing conditions. Above this (units 6e to 7) strata are more clastic and less coaly; interbedded strata show a coarsening-up trend that reached maximum regression in units 6f and 7. Higher in the section the transition from Higgs' Unit I to II (1991) occurs; predominantly sands are followed by sands and silts with a gradual fining-up trend in units 8 and 9 as regional subsidence progressed in the lower Pliocene.

The pattern seen in Sockeye B-10 (Shell Canada LTD., 1968b) is correlative to Sockeye E-66 (units 7 to 10; Figure C1) but the strata in the latter are more condensed indicating a position on the basin edge and/or a structural high. It is not known if there are missing units in the Miocene interbedded clastic and coaly sequences (equivalent to Unit II, lower; Higgs, 1991) that overlay Cretaceous volcanics (Young, 1981; 118$\pm$7 Ma) and Mesozoic strata. Above, clastic sandstone and siltstone units (unit 10) dominated showing a very gradual overall fining-up sequence with no coaly intervals. This was followed by gradual clastic fining-up (unit 11) with carbonaceous and occasional calcitic/marine intervals indicating gradual subsidence in the lower Pliocene that is correlative with Sockeye B-10 units 8 and 9.

Moving south, a change in sub-basin and structure at the base of the Murrelet well (Shell Canada LTD., 1969b) is indicated by the presence of Cenozoic volcanics in unit 2 (Figure C1) (39 Ma, Young, 1981), and the apparent absence of Mesozoic volcanics and strata. Although the nature of unit 1is unknown; it is possibly Mesozoic or Cenozoic (Shell Canada LTD., 1969b; Shouldice 1971, 1973). Overlying sediments (unit 3) were Miocene interbedded calcareous marine clastics with some coals that were more prominent basally indicating a correlation with Higgs' Unit II, lower (1991). Unit 4 contained mainly sandstones with some finer-grained intervals and coals that showed a slight fining-up signature indicating commencement of gradual regional subsidence within Higgs' Unit II, upper (1991). The presence of foraminifers in the basal part of the well (unit 3) indicates an early to middle Miocene neritic environment (Shell Canada LTD., 1969b; Patterson, 1989) with decreasing calcareous intervals above in units 4 and 5 in the transition through to the lower Pliocene.

The Auklet well (Shell Canada LTD., 1968d) (Figure C1, unit 1) penetrated Cenozoic volcanics at its base (36±4 Ma, Young, 1981; 36.7±8 Ma, Hyndman and Hamilton, 1991) although the rocks are so altered that these dates are probably unreliable. Overlying Miocene strata (units 2 to 4) are correlative to similar units in the Murrelet and other wells further north. They differ by being sandier, variously calcareous, and with fewer coals showing the tidal-shelf association described by Higgs (1991). A structural high may be indicated with more condensed Miocene and lower Pliocene units than in the Murrelet to the north and a more condensed Miocene than in the Harlequin to the south.

Features that highlight the Harlequin well (Shell Canada LTD. 1968f) are the: 1) volcanics at the base (42±2 Ma, Young, 1981; 42.8±4 Ma, Hyndman and Hamilton, 1991) (Figure C1, unit 1) although, again alteration may make these dates unreliable; 2) the presence of lower to middle Miocene interbedded carbonaceous (less coal) and calcareous clastic units (unit 3) are probably correlative with Unit II (lower) but with tidal-shelf associations (Higgs, 1991) or a neritic environment (Hopkins, 1975, 1981; Patterson, 1989); 4) thick overlying, sands and occasional silts/shales with a slight fining-up trend (units 4 and 5) that were occasionally calcareous and glauconitic but less so upwards into the Pliocene indicating a structural high during the Pliocene and/or possibly erosion; and 6) the presence of bentonites in units 3 and 4.

The Osprey well (Shell Canada LTD., 1968e) penetrated several intervals of interfingered sedimentary units and various aged Cenozoic volcanics (from <10 to 57.7±7 Ma based on 5 dates) (Young, 1981; Hyndman and Hamilton, 1991) although these dates are probably unreliable due to alteration. Overlying strata were marine interbedded clastics containing lower Miocene slope foraminifers (unit 3) (Shell Canada LTD., 1968e; Patterson, 1989) and units indicating a storm-dominated shelf facies (Higgs, 1991) with fewer marine indicators into the Pliocene. Bentonites were reported in Miocene units 2 and 3 and the lower Pliocene unit 5.

C.3 Summary and Discussion

The Queen Charlotte Basin fill as defined by Higgs (1991) contained Cenozoic volcanics (Masset) intercalated with the sedimentary Skonun formation strata [Unit 1] and deposited in an extensional graben/half-graben environment active in the Miocene and possibly originating earlier. This is overlain by a sequence set of Miocene clastics, coals and carbonaceous materials that coarsen-upwards [Unit II, lower] to a maximum regression for that sequence in the upper Miocene/lower Pliocene. This was then overlain by a sequence set of gradual fining-up strata within a mainly lower Pliocene subsiding basin. Higgs (1991) recognized facies associations including delta-plain, tidal-shelf, and storm-dominated shelf with an overall general north to south deepening pattern across Hecate Strait and Queen Charlotte Sound. More uplift and erosion of Cenozoic strata occurred in south western QCI than in the northeast. Basin faulted structural high and low features were interpreted in Hecate Strait from seismic surveys, and Shell Canada well logs and reports (Shouldice, 1971, 1973; Young, 1981; Rohr and Dietrich, 1992, and others). Most of the previous study results are in agreement with this analysis and correlation. However, the following differences or issues require further comment.

- In comparison to Shouldice (1971, 1973), additional potential marine indicators (e.g. glauconite, calcite, pyrite; Figure C1) have been recognized in the Hecate Strait wells. These suggest a potential for more marine conditions within the interbedded units of clastics, coals, and carbonaceous materials that would be equivalent to Unit II, lower of Higgs (1991). Also, Higgs (1991) recognized marine intervals in the onshore strata and boreholes. Of particular interest are the conglomerate beds in the Cinola gold property strata interpreted as mass-flow or turbidity current deposits into a fan-delta slope (Higgs, 1991). The presence of a variety of mainly lower to middle Miocene interbedded clastic lithologies and coals, bitumen, and carbonaceous materials in the Higgs Unit II (lower) strata overlying Mesozoic volcanic and sedimentary and/or intercalated Cenozoic volcanic/sedimentary units could provide possible hydrocarbon exploration targets under the right conditions of source, reservoir and seal units.
- The late Miocene/early Pliocene boundary indicated by a change in flora taxa (Shell Canada Ltd., 1968a, b, c, d, e, f, 1969a, b; Martin & Rouse, 1966; Shouldice, 1971; Hopkins, 1981, 1975; White et al., 1994) was variably positioned within fining-up in the offshore wells. This boundary frequently has been used by Shouldice (1971, 1973) and others for correlation and interpretation of the QCB well strata. The boundary occurs in changing environment depths and conditions over time in response to overall basin subsidence affected by smaller regional uplift, faulting, and/or other events.
- Inconsistencies exist with interpretations of the position of lower Pliocene strata within the Sockeye B-10 well (e.g. Shell Canada LTD., 1968b; 803-4600'; Dietrich 1995, Figure 3, 8; Rohr and Dietrich, 1992; Hannigan et al., 2001, fig 9). These inconsistencies may be resolved by trying to correlate various strata (see above) or by the absence of upper Pliocene strata in the well.
- Volcanics indicated in the Shell Canada reports (1968a;1969a) near the base of Coho (units 1, 2) and Tyee (units 3 to 5) may be correlative with Masset volcanics and intercalated sediments observed in outcrop and boreholes on the QCI.
- Further subdivision of the lower Pliocene may be possible with more detailed documentation of lithology and well log interpretation. The signature variation is most evident in the northern Hecate Strait wells and is of interest with its interbedded clastic, coal, and carbonaceous units (Coho and Tyee) and hydrocarbon shows in the Sockeye B-10 well.

- The upper Pliocene was commonly absent in the Shell wells but when present, it contained common sands with rare to no flora/fauna indicators (e.g. Osprey [unit 6b], and questionable sands near the top of Coho [unit 11] and Tyee [units 13-15] (Shell Canada LTD., 1968a, e; 1969a). This interval correlates with significant cooling and commencement of regional glaciation (Clague et al., 1982) and development of an associated unconformity. Pleistocene to Recent units at the top of the wells were commonly interbedded, mixed, and coarse to very fine grained.

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