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PETROLEUM RESOURCE POTENTIAL OF SEDIMENTARY BASINS ON THE PACIFIC MARGIN OF CANADA

By

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Abstract

There are three major sedimentary basins on the Pacific margin of Canada: the Tofino Basin, which overlies the present convergent plate margin west of Vancouver Island; the Queen Charlotte Basin, a transtensional basin lying adjacent to the transform boundary between the North American and Pacific plates; and the Georgia Basin, a sedimentary basin with foreland affinities in Late Cretaceous to Eocene time, which in the southeast is overlain by the Fraser River delta. The location of these sedimentary basins at complex plate margins has resulted in a variety of depositional settings that have affected source rock potential and reservoir development. The plate interactions have resulted in a highly variable and complicated tectonic history, which has influenced trap formation, maturation history and petroleum migration. Limited gas production from Pleistocene sediments in the Fraser delta, a good gas show in a well on the Olympic Peninsula and numerous seepages and other indications of hydrocarbons at surface, in wells and on seismic sections throughout the area, all point to an unrealized hydrocarbon potential. The probabilistic assessment of oil and gas potential for the sedimentary basins on the Pacific margin indicates that the total median estimate of in-place hydrocarbon volumes for all west coast basins is in the order of 1560 million m^3 (9.8 billion barrels) of oil and 1228 billion m^3 (43.4 TCF) of gas. There are no discovered reserves in these west coast plays, but some 97 gas pools larger than 3000 million m^3, and two oil pools larger than 160 million m^3, are expected to be present. Several of the conceptual plays have significant potential with respect to undiscovered gas volume, particularly the Pliocene and Miocene gas plays in Queen Charlotte Basin and the Tertiary structural play in the Tofino region. Estimates for oil potential are less optimistic.

Summary

The oil and gas resource potential in Cenozoic and Mesozoic strata of the sedimentary basins on the Pacific margin of Canada are described in this report. The overall appraisal of the hydrocarbon potential of these west coast basins constitutes one of a series of reports from an ongoing comprehensive update of the total petroleum resource for all the sedimentary basins of Canada. The previous Canada-wide assessment was described in a 1983 Geological Survey of Canada paper (Procter et al., 1983). These subsequent "updated" reports contain major revisions and new estimates of petroleum potential for most parts of Canada. Several additional reports on other sedimentary basins, similar to this volume, are planned.

A petroleum play is defined as a group of prospects forming a common geological population linked by one or more factors such as stratigraphy, structure, reservoir type, or source-rock type. For the west coast basins of Canada (the Queen Charlotte, Georgia, Tofino and Winona basins), ten conceptual plays were defined on the basis of various geological controls, with most plays identified from stratigraphic considerations (e.g., Tertiary and Cretaceous plays). Once defined, the ten plays were each statistically analysed to estimate their petroleum resource potential. Resource numbers (total potential and field sizes) quoted in this report are all median value estimates of in-place hydrocarbon volumes.

The oil and natural gas potential of conceptual plays is calculated using a subjective assessment technique termed *conceptual play analysis*. Conceptual plays are defined as those plays that do not yet have discoveries or established reserves, but which may exist according to geological analyses. Conceptual play analysis assumes that the individual sizes of "pools" in a properly defined play form a natural geological population and that the distribution of pool sizes within that population is lognormal. Judging by previous studies using the *discovery process model* for mature play analysis, lognormal distributions adequately represent geological populations in most cases. Also, if lognormal distributions of individual reservoir parameters are entered into the standard "pool-size" equation, a lognormal distribution of pool or prospect size is derived. The distribution of pool sizes is then combined with an additional distribution describing the number of prospects and the marginal probabilities of risk factors to calculate an estimate of both play

potential and individual undiscovered pool sizes. In conceptual plays, where detailed engineering studies of petroleum reserves are missing, it is proper to identify these accumulations as fields rather than pools. Fields in this context are characterized as one or more oil or gas pools in a single structure or trap.

The estimated undiscovered potential for all plays in the west coast basins of Canada is 1560 million m^3 (9.8 billion bbls.) of in-place oil and 1228 billion m^3 (43.4 TCF) of in-place gas. No reserves have been established in the area; 100 per cent of the resource quoted remains to be discovered.

Results of the conceptual play analysis indicate that three plays have high potential for containing significant amounts of gas. These are: 1) the Pliocene gas play in the Queen Charlotte Basin region; 2) the Queen Charlotte Miocene gas play; and 3) the Tofino structural gas play.

Total estimated in-place oil and gas potential for the six Queen Charlotte conceptual plays (i.e., oil and gas components in three defined plays) is 1560 million m^3 (9.8 billion bbls.) and 734 billion m^3 (25.9 TCF), respectively. Estimated oil resource in three of the Queen Charlotte plays is slightly less abundant than gas in terms of energy-equivalent volumes. The combined presence of abundant reservoir strata, good petroleum source rock, numerous and diverse structural traps and the common occurrence of oil and gas shows reflect the significant potential for petroleum accumulations. The most prospective areas occur in Neogene strata within the Queen Charlotte Basin, beneath eastern Graham Island and in the offshore shelf areas of Dixon Entrance, Hecate Strait and Queen Charlotte Sound. Forty-one undiscovered gas fields with in-place gas volumes of 3000 million m^3 (~ 100 BCF) or larger are predicted to be present in these three gas plays. Also, two fields greater than 160 million m^3 (1 billion bbls.) of original in-place oil are anticipated for the three oil plays. Considerable potential is recognized in at least two gas plays in the Queen Charlotte area, making renewed exploration attractive. The current assessment indicates a substantially greater petroleum resource potential for the Queen Charlotte Basin region than previously thought (Procter et al., 1983).

The total estimated potential for three Georgia Basin conceptual plays is 185 billion m^3 (6.5 TCF) of in-place gas. Available geochemical information indicates there is little oil potential in the Georgia Basin or Tofino regions and as such no oil play assessments were prepared for these areas. Eighteen undiscovered gas fields with in-place gas volumes of greater than 3000 million m^3 are predicted to occur in two gas plays. Significant potential is predicted for the Georgia Cretaceous structural play even with substantial risk assigned to adequacy of reservoir and source rock. The presence of large closed structures and large play area increases play potential.

The Tofino Basin region has a single defined play. The potential for the play is 266 billion m^3 (9.4 TCF) of in-place gas. Thirty-eight fields with more than 3000 million m^3 gas volume are predicted to occur, indicating considerable gas potential in this single play. Substantial risk was assigned to reservoir facies and source rock in this play, but the abundance of large structures across a vast area provide the framework for a moderately favourable resource estimate.

INTRODUCTION

Scope

Regional petroleum resource assessments have been prepared periodically for various sedimentary basins in Canada by the Geological Survey of Canada. These studies incorporate systematic basin analysis and statistical resource evaluations (Podruski et al., 1988; Wade et al., 1989; Sinclair et al., 1992; Reinson et al., 1993; Bird et al., 1994; Dixon et al., 1994). This report summarizes the assessment of oil and gas potential in the Queen Charlotte Basin and environs, as well as the Tofino, Winona, Juan de Fuca and Georgia basins surrounding Vancouver Island. These basins constitute the principal hydrocarbon-prospective sedimentary accumulations along the Pacific margin of Canada. It is important to note that while both oil and gas resources were evaluated in the Queen Charlotte Basin region, only gas plays were estimated in the remainder of the Pacific coast area. Geochemical data indicate the Georgia and Tofino basins are probably gas-prone, with little if any oil potential.

Based on geographic and tectonic considerations, the basins and sub-basins along the west coast of Canada were grouped into three general assessment regions: Queen Charlotte, Georgia, and Tofino. The Queen Charlotte assessment region includes the Queen Charlotte and Hecate basins and surrounding smaller sub-basins in Dixon Entrance and near Banks Island in onshore and continental shelf areas, and the deep-water Queen Charlotte Terrace west of the Queen Charlotte Islands (Figs. 1, 2). The Georgia assessment region includes the onshore–offshore Bellingham, Nanaimo, Comox and Suquash sub-basins and surrounding unnamed smaller sub-basins. These sub-basins encompass the Fraser River lowlands and delta, the Strait of Georgia, the Gulf Islands, and the eastern shore of Vancouver Island in southwestern British Columbia and Whatcom County in northwestern Washington State (Figs. 1, 2, 3). The Tofino assessment region includes the Tofino Basin and Juan de Fuca sub-basin beneath the continental shelf, and the deep-water Winona Basin and accretionary wedge seaward of the continental shelf edge (Figs. 1, 2). Some of the basins and sub-basins within the assessment regions extend into the United States (Washington State in the south, Alaska in the north). Relevant geological information from American parts of the basins were evaluated during the assessment studies, and total resource estimate numbers apply to the combined Canadian and American areas. Estimates for Canadian areas only are given later in the report.

Purpose

The objective of this report is to provide an overview of the petroleum geology of Canada's west coast basins and to present quantitative estimates of the oil and gas resources contained therein. This geological and resource framework will assist government agencies in evaluating land-use and moratorium issues, and petroleum industry companies in pursuing future exploration opportunities.

Terminology

The terminology and procedures used in this report follow those outlined in Reinson et al. (1993) and are summarized below.

Oil is defined as any naturally occurring liquid that, at the conditions under which it is measured or estimated, is primarily composed of hydrocarbon molecules and is readily producible from a borehole.

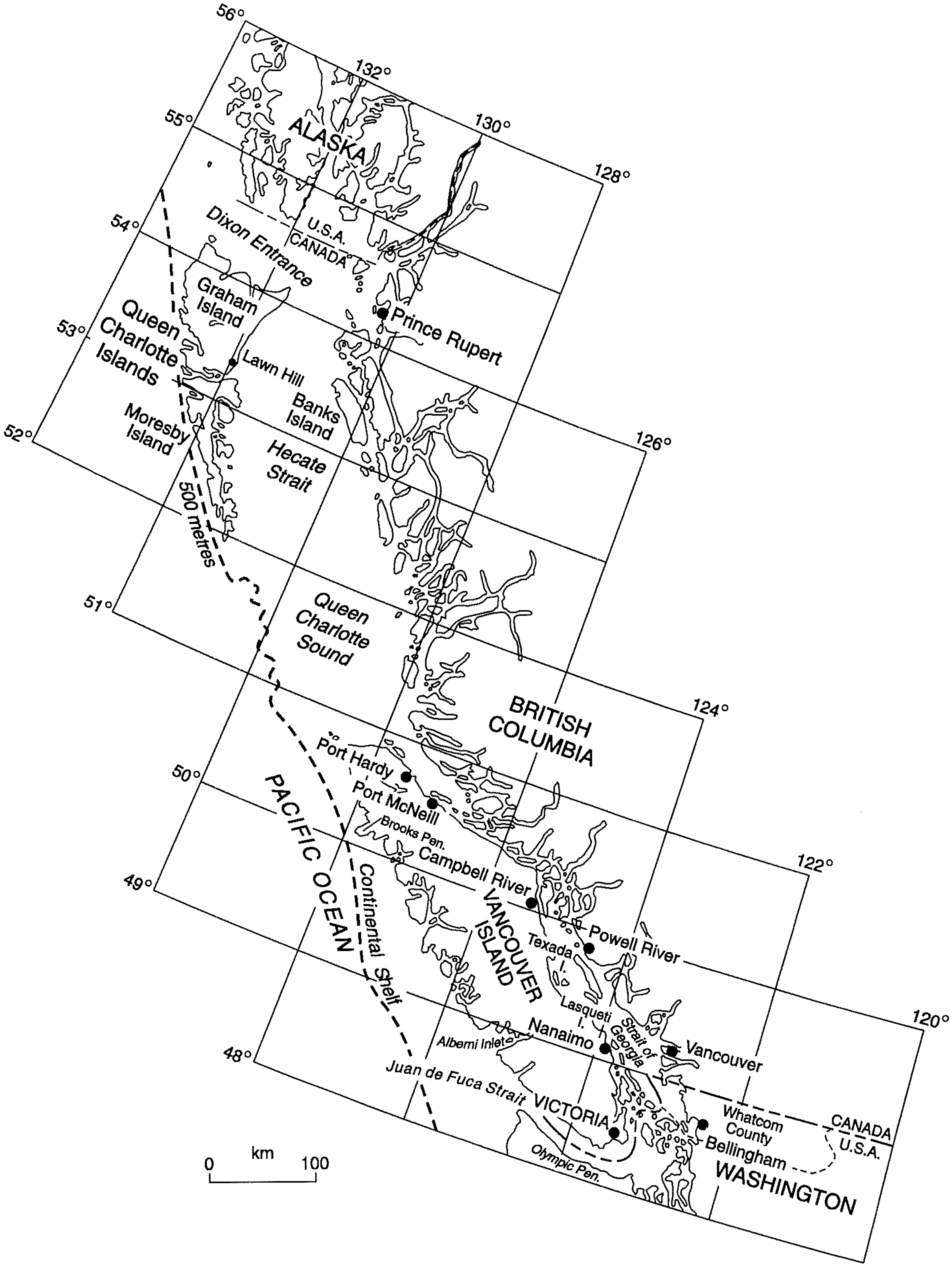

Figure 1. Geographic setting of the west coast region of Canada. Place names and geographic features mentioned in text are shown.

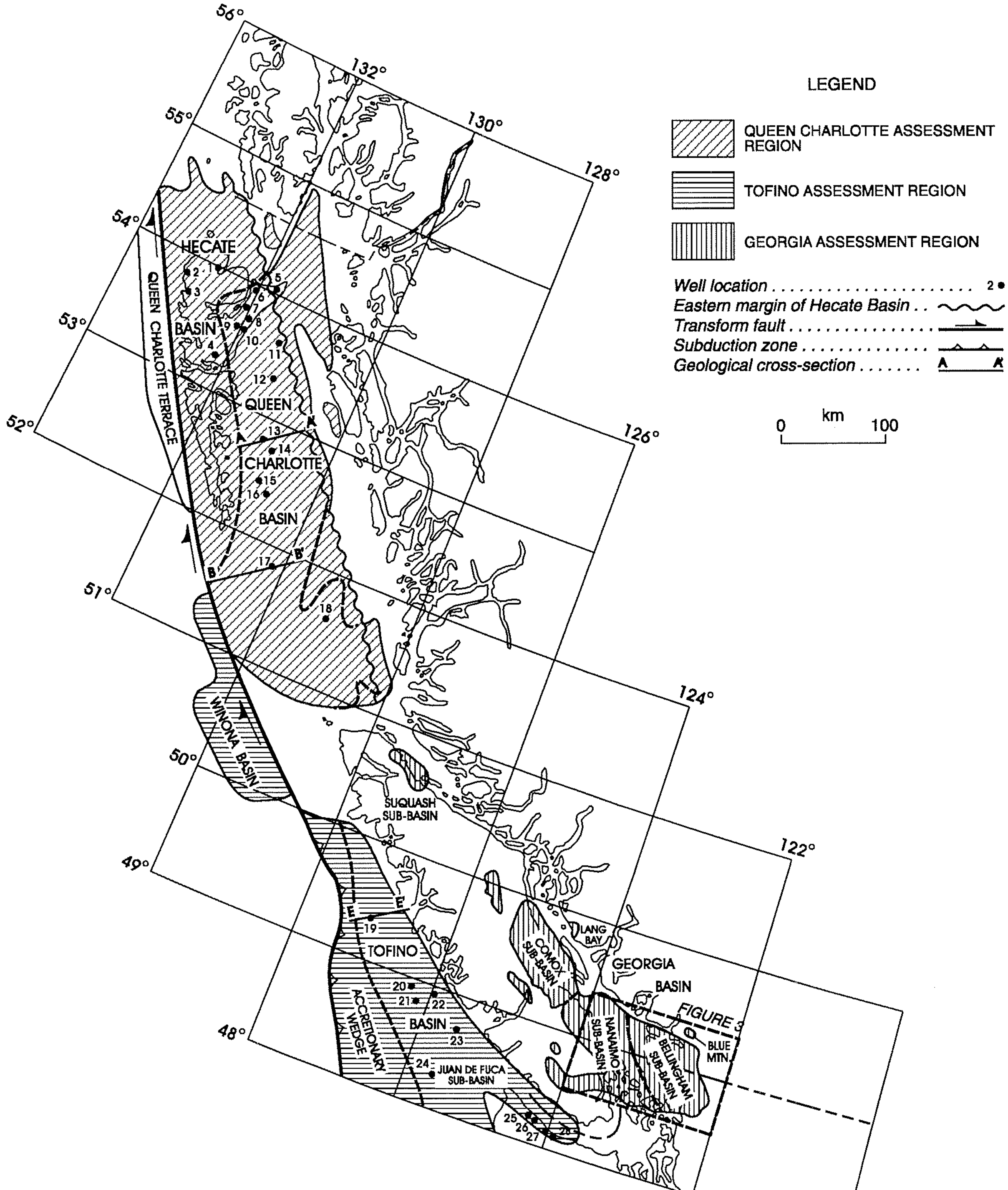

Figure 2. Regional setting and basin outlines of the west coast region of Canada. Assessment regions are shaded. Eastern edge of Hecate Basin modified from Haggart (1993). Well names are listed in Table 1 and cross-sections **A-A´**, **B-B´** and **E-E´** are discussed in text.

Table 1: Well reference numbers

QUEEN CHARLOTTE BASIN (Fig. 2)	
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
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
TOFINO BASIN	
19	Shell Anglo Apollo J-14
20	Shell Anglo Zeus I-65
21	Shell Anglo Zeus D-14
22	Shell Anglo Pluto I-87
23	Shell Anglo Prometheus H-68
24	Shell Anglo Cygnet J-100
JUAN DE FUCA SUB-BASIN	
25	Merrill-Ring No. 1
26	R. D. Merrill No. 1
27	Merrill & Ring No. 25-1
28	Twin River State No. 30-1

Natural gas is defined as any gas (at standard pressure and temperature, 101.33 kPa and 15°C) of natural origin comprising mostly hydrocarbon molecules producible from a borehole (Potential Gas Committee, 1990). Natural gas may contain significant amounts of non-hydrocarbon gas such as H_2S, CO_2 or He. In this study, non-hydrocarbon gas was not considered because of a lack of information on gas compositions in these basins.

Raw gas is unprocessed natural gas, containing methane, inert and acid gases, impurities and other hydrocarbons, some of which can be recovered as liquids. *Sales gas* or *marketable gas* is natural gas that meets specifications for end use. This usually requires processing that removes acid gases, impurities and hydrocarbon liquids. *Nonassociated gas* is natural gas that is not in contact with oil in a reservoir. *Associated gas* is natural gas that occurs in oil reservoirs as free gas. *Solution gas* is natural gas that is dissolved in crude oil in reservoirs. In this report, insufficient information is available to differentiate nonassociated, associated, and solution gas. All gas figures reported represent initial raw gas volumes.

Resource indicates all hydrocarbon accumulations known or inferred to exist. *Resource, resource endowment* and *endowment* are synonymous and can be used interchangeably. *Reserves* are that portion of the resource that have been discovered, while *potential* represents the portion of the resource not yet discovered but inferred to exist. The terms *potential* and *undiscovered resources* are synonymous and may be used interchangeably. Since no oil or gas pools or fields have yet been discovered in any west coast basin, all of the hydrocarbon volumes presented in this report represent potential or undiscovered resource figures.

Gas-in-place indicates the gas volume found in the ground, regardless of what portion is recoverable. *Initial in-place volume* is the gross volume of raw gas, before production. *Recoverable in-place volume*

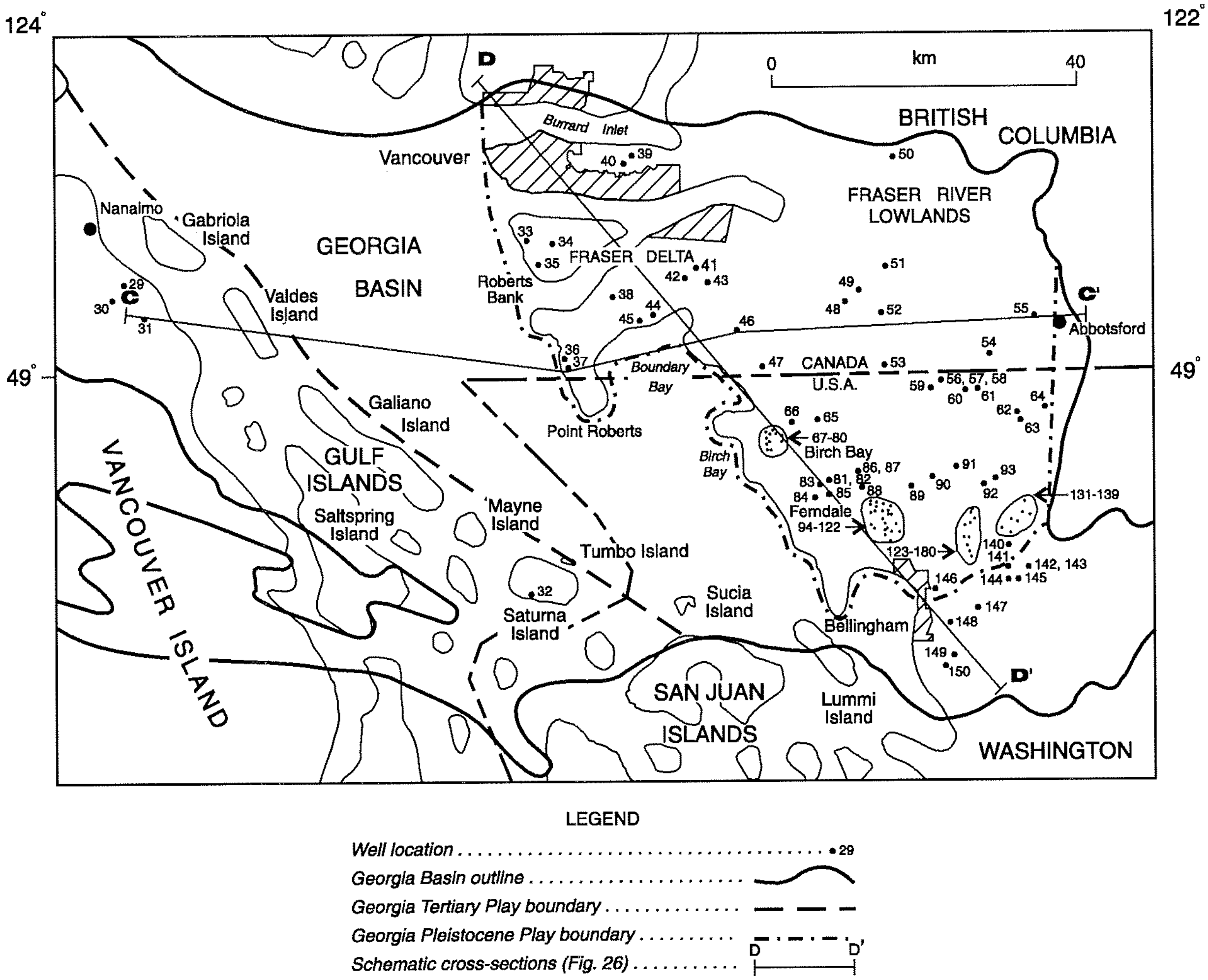

Figure 3. Detail map of Georgia Basin in Vancouver area, the Fraser River lowlands and delta, southeastern Vancouver Island and Gulf Islands of British Columbia and northwestern Washington. Well names are listed in Table 2 and cross-sections **C-C′** and **D-D′** are discussed in text. Place names and geographic features mentioned in text are shown.

represents the volume expected to be recovered with current technology and costs. These definitions can be applied to oil volumes as well.

A *prospect* is defined as an untested exploration target within a single stratigraphic interval; it may or may not contain hydrocarbons. A prospect is not synonymous with an undiscovered pool. An undiscovered pool is a prospect that contains hydrocarbons but has not been tested as yet. A *pool* is defined as a discovered accumulation of oil or gas, typically within a single stratigraphic interval, that is separate, hydrodynamically or otherwise, from another hydrocarbon accumulation. A *field* consists of one or more oil and/or gas pools within a single structure or trap. Similar to most frontier regions, the assessment of west coast petroleum resources is based on estimates of field rather than pool sizes. A *play* is defined as a family of pools and/or

Table 2: Well reference numbers

GEORGIA BASIN (Fig. 3)			
CANADA			
29	BP Laurel Harmac c-36-F	43	Noble Francis No. 1
30	Novacorp Cedar b-29-F	44	Conoco Dynamic Mud Bay
31	BP Yellow Point d-84-C	45	Boundary Bay No. 3
32	Charter et al. Saturna No. 1	46	Richfield Pure Sunnyside 16-13
33	Gulf Ridge No. 1	47	Royal Can-Van Tor Big Horn Kuhn No. 1
34	Royal City No. 1	48	Outwest d-89-A
35	Fritts (Steveston well)	49	Conoco Dynamic Murray Creek
36	Great Basins No. 1	50	Port Haney
37	Richfield Pure Point Roberts 6-3-5	51	Siloam No. 1
38	Smith Savage No. 1	52	Empire No. 3
39	Spartan No. 2	53	Conoco Dynamic Stateside Campbell River
40	Spartan No. 1	54	Hercon Key Evans No. 1
41	Allenbee South Brazeau No. 1	55	Richfield Pure Abbotsford 16-17-16
42	Surrey Dome No. 1		
UNITED STATES			
56	Ridgeway-Heppner No. 1	104	Lingbloom No. 3
57	Ridgeway-Heppner No. 1A	105	Lingbloom No. 1 (Chamber of Commerce No. 1)
58	Ridgeway-Heppner No. 2	106	Peoples No. 1 (P.G.O. Lingbloom No. 1)
59	Kris Whatcom No.	107	Lingbloom No. 2 (Chamber of Commerce No. 2)
60	Stremler No. 2	108	Lingbloom No. 4 (Chamber of Commerce No. 4)
61	Lynden (Stremler) No. 1	109	Beyers No. 1
62	Ives No. 1	110	Bettsinger No. 2
63	Ives No. 2	111	Harden No. 1 (Hunter No. 1)
64	Thom No. 1	112	Bettsinger No. 1
65	Selien No. 1	113	Hunter No. 3
66	International No. 6	114	Harden No. 2 (Hunter No. 2)
67	AHEL Birch Bay No. 1	115	Chamber of Commerce No. 5
68	Heinrich No. 1	116	King No. 1 (Hale No. 1)
69	Johnson No. 1	117	Peoples No. 3
70	Seline No. 1	118	Peoples No. 4
71	Dahle No. 2	119	Peoples No. 6
72	Dahle No. 1	120	Peoples No. 5
73	Hillje No. 2	121	Shale Oil & Gas No. 1
74	Hillje No. 1	122	Hanson No. 1
75	Anderson	123	Holman Water Well No. 2
76	Home Birch Bay No. 1	124	Holman Water Well No. 1
77	Mills No. 1	125	Holman No. 3
78	Home No. 1	126	Water Well
79	Standard Ferndale (Community)	127	International No. 3
80	Hart No. 1	128	Jepson Water Well
81	Acme No. 1	129	Ridge No. 1
82	Acme No. 2	130	Ridge No. 2
83	Soderberg No. 1	131	Water Well
84	AHEL Terrell No. 1	132	Erickson Water Well
85	Sherman No. 1	133	Bellingham Natural Gas Company No. 1
86	Enterprise No. 1	134	Bellingham Natural Gas Company No. 2
87	Enterprise No. 2	135	Bellingham Natural Gas Company No. 3
88	Greenacres Water Well	136	Green Water Well
89	Sinnes Water Well	137	Water Well
90	International No. 5 (Laurel)	138	Barnhart Water Well
91	Hillebrecht No. 1	139	Water Well
92	International No. 4	140	Diamond Drill Hole
93	Russler No. 1	141	Molin No. 1
94	AHEL Ferndale No. 1	142	Ross No. 1
95	Lange No. 1	143	El Paso Ross No. 1
96	Lange No. 2	144	Can Am Squalicum No. 1
97	Lange Coal Test	145	Jensen No. 1
98	Livermore No. 1	146	Stewart-Hamilton
99	Cowden No. 1	147	Luce Water Well
100	Whatcom No. 2	148	Pelican Dome No. 1
101	Whatcom No. 1 (Lange No. 3)	149	Clark Water Well
102	North Coast No. 1	150	Happy Valley (Fairhaven)
103	Peoples No. 6		

prospects that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration.

Plays are grouped into two categories; *established* and *conceptual* plays. *Established plays* are demonstrated to exist by the discovery of pools with established reserves. *Conceptual plays* are those that have no discoveries or reserves, but which may exist, according to geological analyses. Established plays are categorized further into *mature* and *immature* plays depending on the adequacy of play data for statistical analysis. Mature plays are those plays that have sufficient numbers of discoveries within the discovery sequence so that the *discovery process model* of the PETRIMES assessment procedure is of practical use (Lee and Tzeng, 1989; Lee and Wang, 1990; Lee, 1993). Immature plays do not have a sufficient number of discoveries with established reserves to properly apply the model. Conceptual play analysis was applied exclusively in this study because of the lack of any discovered pools with established reserves.

Method and content

This report incorporates two essential components: geological basin analysis and statistical assessment. Basin analysis fundamentally describes and characterizes the exploration play. Fields and prospects in a play form a natural geological population that can be delimited areally. Once a play is defined, a numerical and statistical resource assessment is undertaken using field or prospect data from that specific play.

The analysis of oil and gas potential in the Queen Charlotte, Georgia, Tofino, Winona and Juan de Fuca basins entailed the delineation and the systematic evaluation of 10 conceptual petroleum plays. These plays are summarized with respect to play definition, geology, exploration history and estimated resource potential. This study is based on reviews of published and unpublished data and reports, interpretations and mapping from marine seismic reflection data, evaluation of well history records and logs, modelling of thermal maturation histories, and probabilistic analyses of the plays.

Previous assessments

Based on early drilling results and initial accounts of the regions's geological setting (Sutherland Brown, 1968; Shouldice, 1971), a quantitative assessment of petroleum potential in the West Coast region was prepared by the Geological Survey of Canada (Haimala and Procter, 1982). That assessment produced estimates of recoverable petroleum resources of 38.5 million m^3 (241 Mbbl) of oil and 265 billion m^3 (9.4 Tcf) of gas (mean values). Slightly modifying the 1982 estimates, Procter et al. (1983) presented west coast petroleum potential estimates (average expectations) of 50 million m^3 (315 Mbbl) and 270 billion m^3 (9.5 Tcf) of recoverable oil and gas, respectively. By frontier basin standards, these estimates suggest a small resource potential.

Since publication of the early 1980's assessments, numerous studies have been undertaken in the region and considerable amounts of new geological and geophysical data collected. Qualitative assessments of petroleum potential in the Queen Charlotte Basin region have been presented in a number of recent papers incorporating results from the Geological Survey of Canada's Frontier Geoscience Program. Yorath (1987) stated that the Queen Charlotte Basin contains the highest potential for hydrocarbon accumulation; Georgia and Tofino basins have less potential as a result of porosity and source rock risks in the sedimentary succession. Gordy (1988) concluded that Georgia Basin is gas-prone with a high likelihood for the presence of closed hydrocarbon-bearing structures. Thompson et al. (1991) presented a generally positive view on petroleum potential by comparing the geology of the Queen Charlotte Islands area to the petroleum-producing Cook Inlet Basin of Alaska. In an assessment of the southern Queen Charlotte Islands and adjacent shelf areas, Dietrich et al. (1992) identified tracts of varying petroleum potential, including low potential for onshore and nearshore areas and moderate-to-high potential of offshore areas in Hecate Strait. Lyatsky and Haggart (1993) concluded that the Queen Charlotte Sound area has high petroleum potential, based on interpretations of regional distributions of reservoir and source rocks.

Tectonic setting

Prior to general acceptance of the plate tectonic theory in the early 1970s, the Canadian Cordillera was divided into two belts using the classical geosynclinal hypothesis (Daly, 1912; Kay, 1951; White, 1959; King, 1969). An eastern belt consisting of sedimentary rocks with lesser volcanic and intrusive rocks was classified as a miogeosyncline, while the western belt, containing abundant volcanic, plutonic and metamorphic rocks, comprised the eugeosyncline. Knowledge of plate tectonic processes was used by Monger et al. (1972) to identify five major morphogeological belts in the Cordillera. The five belts, from east to west, are Foreland, Omineca, Intermontane, Coast and Insular. Pertinent to this study are the Insular Belt and, to a lesser extent, the Coast Belt. Individual belts may encompass numerous tectonic settings, such as ancient volcanic arcs, plutonic–metamorphic complexes, oceanic crust, shelf and slope deposits and successor basins. Coney et al. (1980) identified a series of fault-bounded lithotectonic terranes within the Cordillera that may be "suspect" with respect to North American paleogeography. These exotic terranes are believed to have been accreted to the western continental margin of ancestral North America during the Mesozoic (Monger et al., 1982). Sometimes, these exotic terranes were amalgamated outboard of the continent to form superterranes prior to attachment to the continent. Subsequent to accretion, these terranes became disrupted along major dextral transcurrent faults. Tipper et al. (1981) divided the Canadian Cordillera into tectonic assemblages. These assemblages bounded by regional faults reflect a specific depositional or tectonic event. Wheeler and McFeely (1991) published a tectonic assemblage map of the Canadian Cordillera that incorporates the current interpretation of the regional tectonic setting. Basins containing thick sedimentary successions that formed during or subsequent to terrane accretion are important elements with respect to petroleum geology in the Cordillera.

The continental–oceanic plate boundary along the west coast of southern Vancouver Island is marked by the Cascadia subduction zone. North of Brooks Peninsula, on the northwest coast of Vancouver Island, the boundary is defined by a dextral transform fault displaying oblique convergence located on the continental shelf edge west of Queen Charlotte Sound and the Queen Charlotte Islands (Fig. 2). The plate boundary is located at or near the present-day shelf edge (approximated by the 500 m isobath, Fig. 1).

The Queen Charlotte Basin region encompasses the Insular Belt within the North American plate and part of the Pacific plate. The Queen Charlotte Terrace overlies Pacific plate oceanic crust. The Georgia Basin region occurs entirely within the North American plate, encompassing parts of the Insular Belt and adjacent Coast Belt. The Tofino Basin region encompasses the outermost parts of the North American plate (including the Pacific Rim and Crescent terranes and other fossil accretionary wedges) and parts of the Explorer and Juan de Fuca plates. The Winona Basin and accretionary wedge overlie oceanic crust of the Explorer and Juan de Fuca plates, respectively.

The Insular Belt comprises several terranes, the largest of which are the Wrangellia and Alexander terranes. Alexander Terrane extends from the St. Elias Mountains in southwestern Yukon to the Coast Mountains north and east of Hecate Strait. Wrangellia constitutes most of the remainder of the belt; that is, the remaining portion of the Queen Charlotte Island region and most of Vancouver Island. Wrangellia also exists in parts of the southwestern Coast Belt. Beneath western and southern Vancouver Island, the Pacific Rim and Crescent terranes have been emplaced beneath Wrangellia along major northwesterly and westerly thrust faults (Fig. 4). The Pacific Rim Terrane, comprising melanges and volcanics, was emplaced against and beneath western and southern Wrangellia in latest Cretaceous or earliest Tertiary time. Subsequently, the ophiolitic Crescent Terrane was accreted beneath the Pacific Rim Terrane commencing in Late Eocene time (Yorath, 1991). According to multichannel seismic profiles (Campbell et al., 1991), even younger terranes have been accreted to the base of Wrangellia. This emplacement and underplating of terranes along with subsequent and current accretion of the modern subduction complex has resulted in both uplift of western Vancouver Island and subsidence of Georgia Basin to the east (Campbell et al., 1991). Timing constraints imposed by apatite fission track dating of the Cowichan fold and thrust system of southern Vancouver Island imply a temporal linkage between the formation of the fold and thrust system during the Middle Eocene and continued accretion of the Pacific Rim and Crescent terranes against Wrangellia at about 45 Ma (England et al., 1997).

RESOURCE ASSESSMENT PROCEDURE

Geological play definition

Definition of play type and play area are essential objectives of the geological basin analysis that precedes any numerical resource evaluation procedure. A properly defined play will possess a single population of pools and/or prospects that satisfies the assumption that geological parameters within a play can be approximated by a family of lognormal distributions. A mixed population derived from an improperly defined play adds uncertainty to the resource estimate. Pools and/or prospects in a specific play form a natural geological population characterized by one or more of the following: age, depositional model, structural style, trapping mechanism, geometry, and diagenesis. Prospects or areas within a basin or region can be assigned to specific plays on the basis of a commonality of some or all of these geological elements.

Compilation of play data

Since conceptual plays have no defined pools or discoveries, probability distributions of reservoir parameters such as prospect area, reservoir thickness, porosity, trap fill, and hydrocarbon fraction are needed. Prospect size can then be calculated using the standard "pool"-size equation. Seismic, well, and outcrop data prove particularly useful in identifying the limits for sizes of prospect area and reservoir thickness as well as porosity limits. Geochemical data are useful in identifying prospective areas as well as the composition of the hydrocarbon accumulations, that is, oil vs. gas proneness. Research in similar hydrocarbon-bearing basins is also important in order to provide reasonable constraints on reservoir parameters as well as contributing further information on other aspects of petroleum geology that may prove useful for the study.

Conceptual play analysis

There are several methods for estimating the quantity of hydrocarbons that may exist in a play, region or basin (White and Gehman,1979; Masters, 1984; Rice, 1986; Lee, 1993). Petroleum assessments undertaken by the Geological Survey of Canada are currently based on probabilistic methods (Lee and Wang , 1990), developed in the Petroleum Exploration and Resource Evaluation System, PETRIMES (Lee and Tzeng, 1989). The conceptual hydrocarbon plays defined in the West Coast region were analysed by applying a subjective probability approach to the reservoir parameters. The lognormal option in PETRIMES was utilized since experience indicates that geological populations of pool parameters can be adequately represented by lognormal distributions.

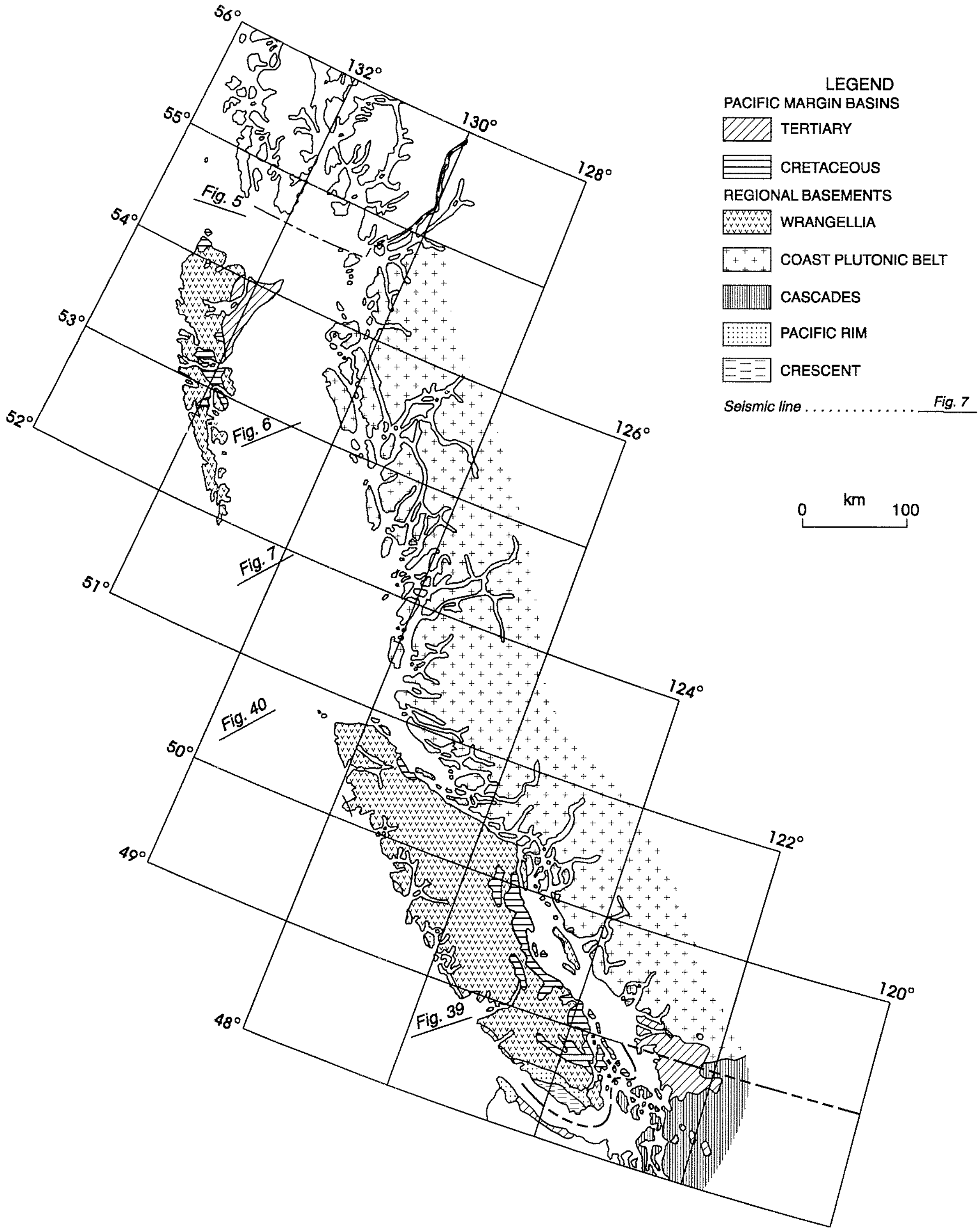

Figure 4. Tertiary and Cretaceous onshore sedimentary basins, west coast region of Canada. Regional basements with respect to basins are illustrated. Example seismic lines are indicated illustrating structural styles in certain areas.

Conceptual resource assessments in the frontier regions use field-size estimates rather than pool-size predictions as derived from mature and immature play analysis. A field consists of one or more oil or gas pools or prospects in a single structure or trap. Probability distributions of oil and gas field sizes are computed by combining probability distributions of reservoir parameters, including prospect area, reservoir thickness, porosity, trap fill, hydrocarbon fraction, oil shrinkage, and gas expansion.

Probability distributions of oil and gas field sizes were combined with estimates of numbers of prospects (from seismic and play area mapping) and exploration risks, to calculate play potential and to estimate sizes of undiscovered fields.

Exploration risks at a play or prospect level are determined on the basis of the presence or adequacy of geological factors necessary for the formation of petroleum accumulations. Essential factors are reservoir, seal, source rock, timing of hydrocarbon generation, trap closure and preservation. Appropriate marginal probabilities are assigned to each geological parameter to obtain risk factors. All of the Queen Charlotte and Vancouver Island plays have a high probability of existing (low risk). Within each play, certain prospect-level risks are high and these are assigned appropriate risk factors. Exploration risk is an estimate, incorporating all risk factors, of the percentage of prospects within a play expected to contain hydrocarbon accumulations.

Because of the nature of conceptual assessment results and since no discovered pool sizes can be used to constrain sizes of undiscovered accumulations, the uncertainty of oil and gas play potential and pool size estimates for a given range of probabilities is necessarily greater than the limits derived by discovery process analysis used in assessing mature plays.

QUEEN CHARLOTTE ASSESSMENT REGION

Exploration history and regional studies

The major phase of offshore exploration in the region was undertaken by Shell Canada Ltd. from 1965 to 1969. Several thousand line-kilometres of marine seismic reflection data were acquired. Shouldice (1971) combined this seismic data with that from aeromagnetic surveys and studies of outcrop geology on the shoreline margins of the Queen Charlotte Basin to analyse and describe the region's geological setting. The overall basin geometry, the gentle folds within the Tertiary sediments and the onlap of Tertiary sediments onto basement were first interpreted from these data. Additional marine seismic surveys were carried out by Chevron Canada Ltd. in 1971. Stacey (1975) used gravity data obtained between 1963 and 1967 by the Canadian government to identify and interpret the geometry and relationships of Upper Tertiary sediments to underlying Mesozoic volcanics and sediments in the offshore Queen Charlotte Basin. One thousand kilometres of marine reflection data were recorded in 1988 by the Geological Survey of Canada in the Queen Charlotte Basin (see Fig. 4 for location of example lines; Figs. 5, 6 and 7) (Rohr and Dietrich, 1990, 1991). Interpretation of these data inferred that the Tertiary sediment succession is highly variable in thickness and the basin fill and underlying basement are extensively faulted to form a complex pattern of sub-basins and half-grabens (Rohr and Dietrich, 1992) (Figs. 5, 6 and 7). These structural features imply a transtensional tectonic setting. A seismic refraction survey (Spence et al., 1991), was also carried out in 1988 by the Geological Survey of Canada. These data were used to estimate crustal thickness in Queen Charlotte Sound. Lyatsky (1991) combined regional magnetic and gravity surveys with physiographic lineaments to construe that the lateral crustal movements accompanying the formation of Tertiary Queen Charlotte Basin were probably small and consequently, no rift-related structures were formed. Lyatsky concluded that a fault-block tectonic pattern likely dominated during the Mesozoic and Cenozoic in the area. An integrated geophysical approach was utilized in the Queen Charlotte Basin by Lowe and Dehler (1995)

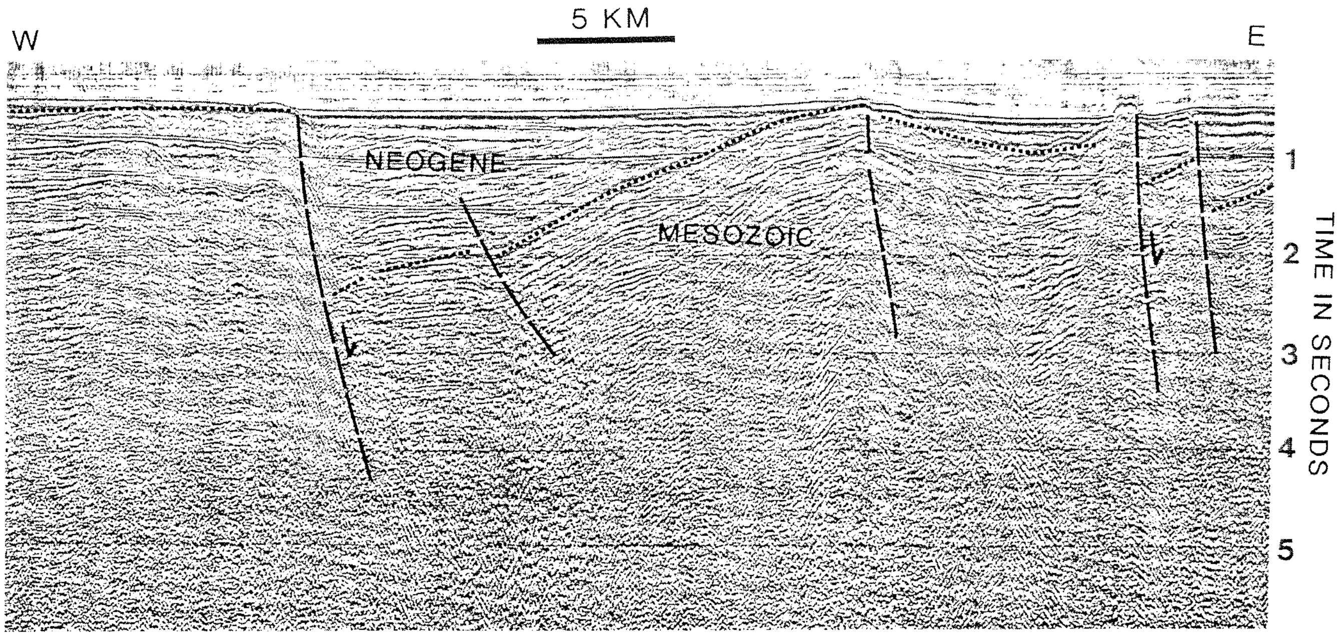

Figure 5. Seismic reflection profile, Dixon Entrance, northern Queen Charlotte Basin (data from Rohr and Dietrich, 1990). Neogene half-grabens and tilted fault blocks are associated with down-to-east normal faults. Neogene sedimentary strata overlie a variable Mesozoic complex of sedimentary, volcanic and plutonic rocks.

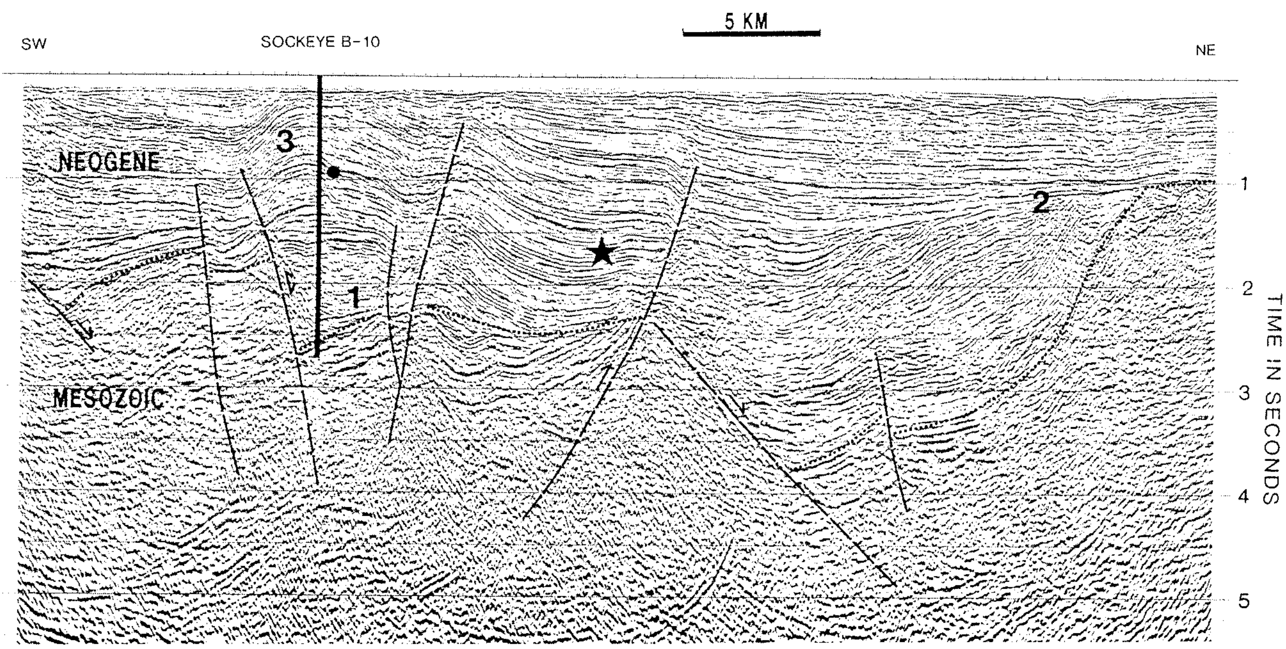

Figure 6. Seismic reflection profile, Hecate Strait, central Queen Charlotte Basin (data from Rohr and Dietrich, 1990). Structural features include Mesozoic half-grabens and rift blocks [and associated normal faults (1)], a Late Miocene unconformity [apparent at profile's east end (2)], and Pliocene reverse faults and inversion folds (3). Solid circle indicates stratigraphic position of oil show (in Miocene sandstones) encountered by the Sockeye B-10 well. Star indicates position of interpreted hydrocarbon indicators.

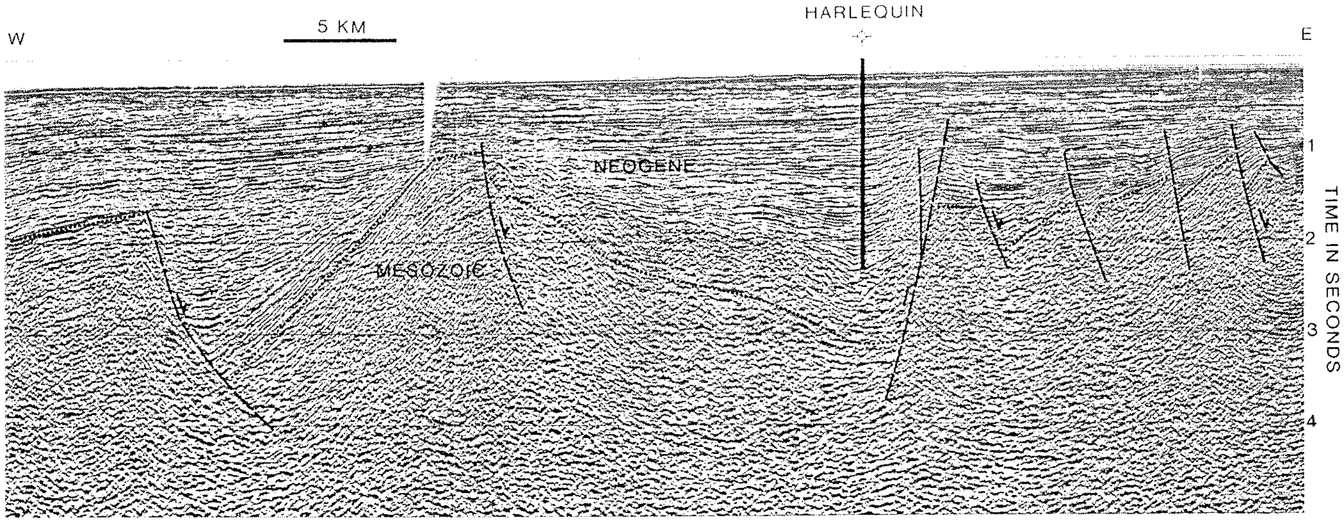

Figure 7. **Seismic reflection profile, Queen Charlotte Sound, southern Queen Charlotte Basin (data from Rohr and Dietrich, 1990). Miocene half-grabens and tilted fault blocks are overlain by relatively undeformed Pliocene strata. The Harlequin well encountered numerous thick sandstones within the Neogene section, many of excellent reservoir quality.**

to calculate crustal thickness. They considered both the deep marine seismic reflection and refraction data collected by the Geological Survey of Canada in 1988 and integrated it with gravity and bathymetry data.

The first petroleum exploration well in the Queen Charlotte Basin region (Tian Bay) was drilled in 1913 on the west coast of Graham Island (see Fig. 2 for well locations and Table 1 for well listings). Eight more wells were drilled onshore (Graham Island) between 1949 and 1971 (Fig. 2) . Richfield Oil Corporation completed six of the wells. The Royalite Oil Company and Union Oil Company each drilled one well (Table 1). Eight offshore wells were completed by Shell Canada Ltd. between 1965 and 1969 (Table 1). Six were drilled in Hecate Strait (Coho, Tyee, Sockeye B-10 and E-66, Murrelet and Auklet) (Shell Canada Ltd., 1968 a,b,c,e , 1969b,c) and two in Queen Charlotte Sound (Harlequin and Osprey) (Fig. 2) (Shell Canada Ltd., 1968d, 1969a). In 1972, the Canadian federal government imposed an indefinite moratorium on petroleum exploration of federal lands in the Pacific offshore in response to environmental concerns. Since that time, petroleum exploration has been limited in the area, with only one onshore well completed on Graham Island (Bow Valley Industries 1984, Naden well).

Regional geology

Geological setting and tectonic evolution

The Queen Charlotte and Hecate basins were previously interpreted as overlying both Wrangellia and Alexander terranes (Yorath and Chase, 1981). The Paleozoic to Lower Mesozoic Wrangellia and Alexander terranes accreted to the North American plate margin in mid-Jurassic time (van der Heyden, 1992). The location of the boundary between the two terranes has important implications for petroleum potential because Wrangellia Terrane contains the region's principal oil source rocks. More recent studies addressing the terrane boundary question indicate that Wrangellian rocks probably occur across most or all of the assessment region (Woodsworth, 1988; Thompson et al., 1991; Wheeler et al., 1991). Hecate Basin is a plate-margin parallel, Cretaceous forearc basin (Dietrich, 1995), that developed in response to post-terrane accretion convergence and orthogonal subduction of the Pacific plate beneath the continental margin. Basin-fill sediments were derived from uplifted coast mountains to the east. Hecate Basin underlies part of the Queen Charlotte Basin and all of Queen Charlotte Islands (Fig. 2). The Queen Charlotte Basin is an upper Tertiary strike–slip basin that developed in response to transtensional and transpressional Pacific–North America plate interactions. Queen Charlotte basin-fill sediments were derived from variable source areas and directions. The Queen Charlotte Terrace is a Plio-Pleistocene sedimentary prism that developed in response to oblique transpression of the Pacific plate against the Queen Charlotte Islands crustal block (Prims et al., 1997).

The Neogene Queen Charlotte Basin is the largest basin on the west coast, encompassing some 40,000 square kilometres. The basin underlies eastern Graham Island and large portions of the continental shelf of Dixon Entrance, Hecate Strait and Queen Charlotte Sound. Northernmost parts of the basin extend into offshore areas of southeast Alaska (Risley et al., 1992). The basin is underlain by Mesozoic and Tertiary volcanic, plutonic and sedimentary rocks, with a geological history linked to evolution of the Pacific continental margin and associated convergent, transcurrent and possible extensional plate interactions (Lewis et al., 1991; Rohr and Dietrich, 1992; Rohr and Currie, 1997). In detail, the Queen Charlotte Basin consists of a series of separate or partly coalesced strike–slip sub-basins, which developed across a 150 km-wide, plate margin–parallel shear zone (Rohr and Dietrich, 1992; Dietrich, 1995). The sub-basins are commonly half grabens bound by northwest- or north-trending normal or oblique–slip faults (Figs. 5, 6, 7). The sub-basins contain syn-rift clastic sediments, and local volcanic flows, characterized by considerable local variability in lithology and thickness. Overlying these deformed sediments is a Pliocene sequence that is relatively undisturbed. These sediments drape the deeper structures and are more laterally continuous. Relatively recent compression and shortening in Hecate Strait is reflected by evidence of reactivation of the block faults and deformation of the sediments. Some erosional truncation of folds at the seafloor suggests very recent deformation (Rohr and Dietrich, 1991).

Stratigraphy and structure

Volcanic rocks of the Wrangellian Triassic Karmutsen Formation are several thousand metres thick and represent "basement" for petroleum exploration in the Queen Charlotte Basin region (Fig. 8). On Queen Charlotte Islands, the Karmutsen Formation is conformably overlain by up to 1000 m of Upper Triassic and Lower Jurassic limestones, sandstones, and shales of the Kunga and Maude groups (Fig. 8). The Kunga Group consists of 200 m of massive carbonate overlain by thin-bedded fossiliferous limestones (Monger et al., 1991). In the uppermost Kunga, the limestone is overlain by argillite of Early Jurassic age with lesser interbedded sandstone and tuff. This unit is up to 400 m thick and is similar to the coeval Harbledown Formation on Vancouver Island. The Lower and Middle Jurassic Maude Group consists of 400 m of shale, shaly limestone, coquinoid sandstone and minor tuff and tuffaceous siltstone. Upper Kunga limestones and argillites and lower Maude shales contain oil source rocks. These rocks are deposited in a stable shelf setting. Principal structures in Lower Mesozoic rocks are northwest-trending folds and thrust faults of Middle Jurassic age (Thompson et al., 1991; Lewis et al., 1991). Karmutsen, Kunga and Maude rocks accumulated in intra-oceanic and island arc settings, as part of the exotic terrane, Wrangellia.

The Wrangellian (Lower Mesozoic) succession is unconformably overlain by several hundred metres of volcanic and volcaniclastic rocks of the Middle Jurassic Yakoun and Moresby groups (Fig. 8). The Yakoun Group comprises of 480 m of volcanic breccia, lapilli tuff, and agglomerate with minor lenticular sandstone and siltstone (Monger et al., 1991). The overlying siliciclastic sediments of the Middle Jurassic Moresby Group consist of siltstones, shales and sandstones with minor pebble conglomerates. The succession varies in thickness from 45 to 200 m. Middle Jurassic and older rocks are locally intruded by late Middle to Late

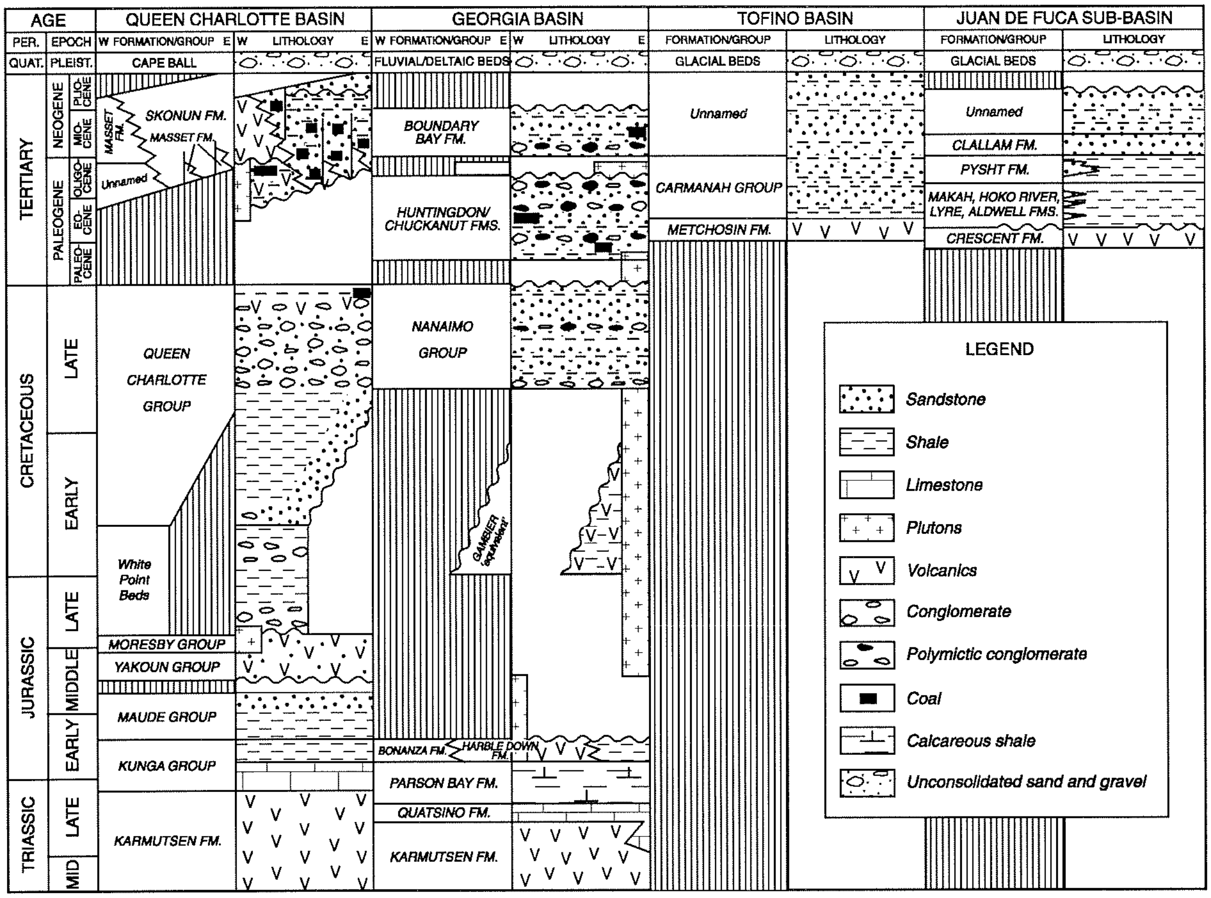

Figure 8. Simplified stratigraphic column for Queen Charlotte, Georgia, Tofino and Juan de Fuca sub-basin regions (modified from Niem and Snavely, 1991; Haggart, 1992, 1993; Mustard and Rouse, 1994). Potential reservoir strata occur in the Skonun Formation and at the base of the Queen Charlotte succession in Queen Charlotte Basin, in coarse clastics of the Huntingdon Formation and Nanaimo Group in Georgia Basin, and in thin coarse clastic intervals in Tofino and Juan de Fuca basins. Petroleum source rocks occur in upper Kunga–lower Maude, lower Skonun, and (?) Upper Queen Charlotte Group strata in Queen Charlotte Basin. Considerable variability exists in the distribution and thickness of all stratigraphic units.

Jurassic plutons of intermediate to felsic compositions. These plutonic bodies are aligned on northwesterly and northerly trends (Sutherland Brown, 1968). They range in composition from hornblende diorite to quartz diorite and dip steeply eastward. The enclosing host rocks, specifically Karmutsen Formation, are metamorphosed to fine grained amphibolites in restricted contact aureoles (Yorath et al., 1991). Unconformably overlying Moresby–Yakoun rocks are up to 2500 m of Upper Jurassic–Cretaceous sandstone, shale and conglomerate of the White Point beds and Queen Charlotte Group. The White Point beds, also known as the Longarm Formation (Haggart, 1993), have both a proximal and a distal facies. Proximal facies-type rocks present in southeastern Moresby Island consist of boulder, pebble and granule conglomerates as well as coarse grained sandstones. The unit is about 180 m thick. There is a pronounced angular unconformity between the White Point beds and underlying Kunga Group rocks in the area. Andesitic clasts similar in composition to the Yakoun Group are found in the conglomerates. Distal facies of the 500 m thick succession include calcareous siltstones, fine to medium grained greywackes and argillites. The greywackes and argillites represent deep-water turbidites. There are also minor andesitic agglomerates and porphyritic flows within the succession. Overlying the White Point beds, probably unconformably, is the mid- to Upper Cretaceous Queen Charlotte Group consisting of shales, sandstones, conglomerates and minor coaly fragments. The basal part of the Queen Charlotte Group consists of a time-transgressive succession (up to 200 m thick) of shallow-marine sandstones and granule conglomerates (Haggart, 1991). Some sandstones and conglomerates in this unit have good reservoir characteristics and are potential petroleum reservoirs. The coarse grained deposits are overlain by several hundred metres of siltstone and carbonaceous shale. Upper parts of the Queen Charlotte Group locally contain volcanic rocks and conglomeratic beds. Structures in Jurassic and Cretaceous strata include northwest-trending contractional folds of early Tertiary age (Lewis et al., 1991).

The Mesozoic succession is locally intruded by Late Eocene to Oligocene plutons and overlain by Upper Eocene to Pliocene clastic sedimentary strata and volcanic rocks (Fig. 8). Unnamed Eocene–Oligocene sedimentary and volcanic rocks form a minor component of the lower Tertiary succession, attaining a maximum thickness of a few hundred metres. Sandstones, shales, argillites and coals with laterally equivalent volcanic rocks are present in this unit.

Neogene volcanic and sedimentary rocks of the Masset and Skonun formations unconformably overlie the Paleogene and older rocks in the Queen Charlotte Basin region and comprise the bulk of the upper Tertiary succession. Neogene volcanic rocks range up to 2000 m in thickness. Basalt and rhyolite flows, pyroclastics and related intrusions constitute the Masset Formation. The Formation is both overlain by and locally interbedded with the Neogene Skonun Formation. The Skonun Formation consists of interbedded sandstone, shale, conglomerate and coal, and is up to 6000 m in thickness in some offshore locations. These rocks were deposited in both marine and nonmarine settings throughout the basin. Structural features within the Queen Charlotte Basin developed in association with Miocene transtensional and Plio-Pleistocene transpressional tectonics (Rohr and Dietrich, 1992). Miocene structures include north- and northwest-aligned normal and oblique–slip faults (Figs. 5, 6, 7, 9; see Fig. 2 for cross-section locations and Fig. 4 for seismic line locations). Pliocene structures in basin-fill strata include reverse faults (commonly developed as inversions of Miocene normal faults), contractional folds and combination fault–fold flower structures (Figs. 6, 9). Pleistocene structural features in the Queen Charlotte Basin and Queen Charlotte Terrace include local folds and tilted, truncated Neogene strata. Pleistocene folding of strata in the Queen Charlotte Terrace occurred in association with transpression of the Pacific Plate against the Queen Charlotte Islands.

Petroleum geology

Reservoirs

Mesozoic

The Upper Jurassic–Cretaceous White Point beds and Queen Charlotte Group (Fig. 8) contain thick sections of sandstone and conglomerate, portions of which have reservoir potential. The best reservoir qualities occur in shallow-marine sandstones and granule conglomerates within the basal part of the Queen Charlotte Group. This time-transgressive unit, referred to as "basal transgressive lithofacies" (Haggart, 1991), contains texturally mature, arkosic sandstones (compositional data in Sutherland Brown, 1968; Fogarassy and Barnes, 1991). The basal transgressive strata were deposited along northwest–southeast aligned paleoshorelines in the Queen Charlotte Islands area and probably the western parts of Dixon Entrance, Hecate Strait and Queen Charlotte Sound (Haggart, 1991; Lyatsky and Haggart, 1993). Fogarassy and Barnes (1991) described the reservoir characteristics of outcrop sections of the basal lithofacies on the Queen Charlotte Islands. Porosity averages 5 to 10%, with values locally exceeding 15%, in the 30 to 190 m thick unit. The observed porosity is a combination of preserved intergranular porosity and appreciable secondary porosity due to calcite dissolution. Permeability is considered fair to good as a result of well-rounded framework grains and lack of clay cements.

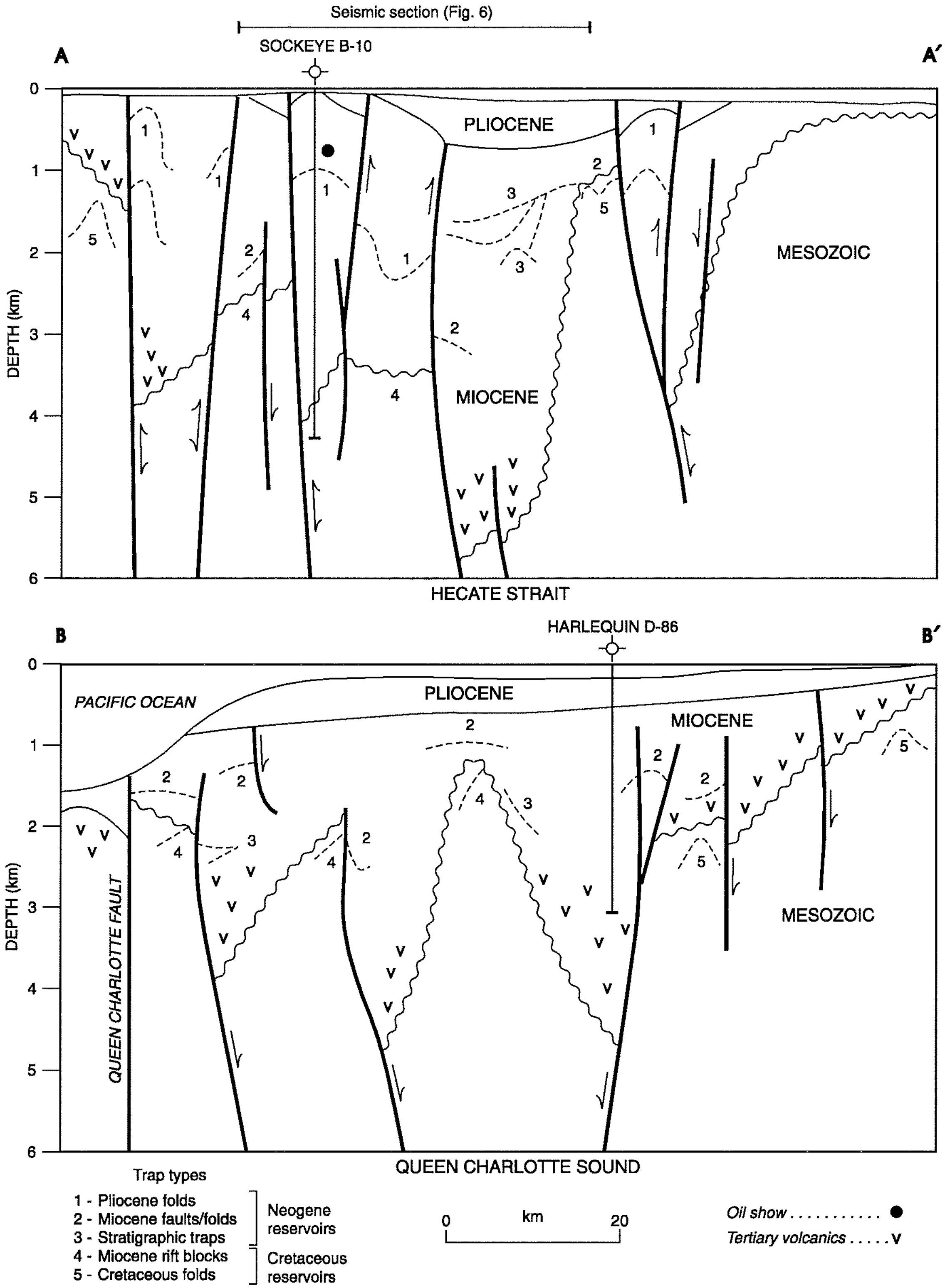

Figure 9. Geological cross-sections (derived from seismic and well data) across Hecate Strait (A-A′) and Queen Charlotte Sound (B-B′; locations in Fig. 2). Numbers (1 to 5) indicate possible petroleum trap types within and beneath the Neogene Queen Charlotte Basin (from Dietrich, 1995).

Other marine sandstones and conglomerates within the Upper Jurassic–Cretaceous succession, while of considerable thickness locally, are characterized by more lithic (commonly volcanic) compositions and have generally poor reservoir potential (Fogarassy and Barnes, 1991). Cretaceous nonmarine strata occur in the subsurface along the east side of Hecate Strait (Fig. 1). Three offshore wells in Hecate Strait (Tyee and Sockeye B-10 and E-66; Figs. 2, 6, 9) penetrated probable Upper Cretaceous coal-bearing nonmarine strata (Haggart, 1991; J. M. White, pers. comm., 1992). Sandstones are abundant in the nonmarine Cretaceous sections penetrated in offshore wells, but in all cases well logs indicate low porosity and permeability (Shell Canada, 1968a, b, c). Although known surface and subsurface occurrences of Cretaceous sandstones (apart from basal transgressive units) are characterized by poor reservoir qualities, Cretaceous strata in parts of Hecate Basin may have improved reservoir potential associated with local developments of secondary porosity (Fogarassy and Barnes, 1991).

Paleogene

Paleogene sedimentary strata in the western Queen Charlotte Basin region may have limited reservoir potential. The Port Louis well on western Graham Island (Fig. 2) penetrated a 575 m thick section of Eocene–Oligocene volcaniclastic sandstone, conglomerate and shale beneath Masset Formation volcanic rocks (White, 1991). Similar sedimentary strata of probable Paleogene age occur in outcrop on Hippa Island, southwest of the Port Louis well location (not shown on Fig. 1; Higgs, 1989; Lewis et al., 1991). Sandstones and conglomerates in both areas are characterized by poor reservoir qualities, as a result of occlusion of pores by decomposition products of volcanic and feldspar grains (Higgs, 1989). Three drillstem tests of low porosity sandstones in the Port Louis well had insignificant recoveries (Union Oil, 1971). Paleogene sedimentary strata undoubtedly occur beneath Masset volcanic rocks in other parts of Graham Island and perhaps elsewhere in the region. These rocks could have locally improved reservoir potential if sandstone compositions differ from known sections (Higgs, 1989). Until additional subsurface control is available, however, assessments of Paleogene reservoir potential will remain equivocal.

Neogene

The Neogene Skonun Formation (Fig. 8) contains large volumes of sandstone and conglomerate that were deposited in a wide range of nonmarine and marine depositional environments, including alluvial fan, fan delta, delta plain, shelf and marine slope settings (Higgs, 1991; Dietrich et al., 1993). Most or all Neogene sub-basins contain a mix of nonmarine and marine strata, with northern sub-basins beneath Graham Island and Hecate Strait containing larger percentages of nonmarine deposits. The wide geographic distribution, large volume and commonly good reservoir characteristics of Skonun sandstones and conglomerates make them the principal petroleum exploration targets in the region. Skonun sandstone and conglomerate beds are up to tens of metres thick, comprise 25 to 75 per cent of the total Neogene sedimentary section, and attain cumulative thicknesses of up to 2000 m in some sub-basins. In the 14 exploration wells that penetrated Skonun strata, only five drillstem tests were completed, all in onshore wells, with the best flow rates recorded from the Tow Hill well (450 barrels of water/day; Richfield Oil Corporation, 1958).

Skonun sandstones are predominantly arkoses and lithic arkoses and generally have the highest mineralogical maturity of all arenaceous rocks in the region (Shouldice, 1971). At depths of less than 2000 m, Skonun sandstones have generally good reservoir qualities, characterized by very high porosity (25 to 35%) and fair to very good permeability (10 to 1500 md) (Dietrich, 1995, figs. 5, 6). At depths from 2000 to 3000 m, Skonun sandstones have high porosity (20 to 30%) and fair permeability (10 to 100 md) (Dietrich, 1995, figs. 5, 7). Skonun reservoir potential is limited below depths of about 3000 m, because of low permeability.

The wide range of permeability in Skonun sandstones and limited correlation between permeability and porosity (Dietrich, 1995, fig. 5) reflect composition-related diagenetic variations. Less permeable sandstones contain greater amounts of pore-bridging clays, products of feldspar grain decomposition (Shouldice, 1971; Fogarassy and Barnes, 1988). Tidal-shelf and storm-dominated shelf sandstones are commonly the most permeable Skonun reservoirs, as a result of advanced textural and compositional maturity (Higgs, 1991). Shelf sandstones occur throughout the Queen Charlotte Basin and are abundant in the southern Queen Charlotte Sound half of the basin and in post-rift sections in the northern half of the basin.

In some areas, Neogene sections contain volcaniclastic sandstones and conglomerates characterized by poor reservoir qualities, even at shallow depths. Low porosity and permeability in volcaniclastic strata are due to advanced cementation associated with diagenesis of volcanic rock fragments (Galloway, 1974). Volcanic and volcaniclastic rocks occur in some (but not all) sub-basins and, where present, usually occur in the oldest syn-rift sections adjacent to basin-bounding faults (Fig. 9). From a regional perspective, volcaniclastic strata comprise a relatively small portion of the basin's total sediment volume.

Seals

Cretaceous and Tertiary reservoir strata are interstratified with shale, siltstone, and volcanic rocks that may provide effective seals for petroleum accumulations. Basal Cretaceous sandstone units are commonly overlain by thick Upper Cretaceous shale sections. In the Graham Island area and parts of the offshore, Neogene volcanic rocks may form seals for Cretaceous or Paleogene reservoirs. The Queen Charlotte Basin contains thick successions (commonly between 1000 and 3000 m depth) of interbedded Neogene reservoir and seal rocks, providing potential for entrapment of oil or gas at many stratigraphic intervals. Impermeable strata are least common in shallow Neogene sections (above 1000 m depth) in the northern half of the basin. Fault-related seals for Tertiary or Cretaceous reservoirs may be associated with impermeable fault zones or cross-fault juxtaposition of permeable and impermeable strata (Figs. 6, 9).

Traps

Table 3 lists the various petroleum trap types expected to occur within the west coast basins according to stratigraphic succession. A variety of potential structural and stratigraphic petroleum traps occurs in Cretaceous and Tertiary strata within and beneath the Queen Charlotte Basin (Fig. 6; numbers 1 to 5 in Fig. 9). Traps involving Cretaceous strata include Late Cretaceous folds and extensional fault blocks (numbers 4 and 5 in Fig. 9). The fault-block traps may be associated with Cretaceous subcrop patterns at the sub-Neogene unconformity (example in Fig. 6, at 2.5s, SP 700). Neogene reservoir strata occur in Miocene to Pleistocene age structural and stratigraphic traps. Miocene structures include tilted fault blocks, fault-related rollover and drag closures and low-relief drape anticlines (number 1 in Fig. 6; number 2 in Fig. 9). Stratigraphic traps may occur in Miocene strata that onlap onto or subcrop below local unconformities, or within cone-shaped alluvial fan or fan delta deposits banked against fault scarps or pinching out updip within half-grabens (number 2 in Fig. 6; number 3 in Fig. 9). Pliocene structural traps, restricted to the northern half of the basin (Hecate Strait and Dixon Entrance), include abundant large-amplitude folds, commonly cut by steep-dipping reverse faults (number 3 in Fig. 6; number 1 in Fig. 9). Most of the Late Pliocene folds in Neogene strata (including the Sockeye anticline, Fig. 6), are structurally detached from underlying Mesozoic rocks. Structural decoupling results in lateral separation of closures in Neogene and Cretaceous strata. Stratigraphic traps may also be locally present in shallow parts of the Queen Charlotte Basin where tilted Neogene strata are unconformably overlain by Quaternary mudstones.

Table 3: Petroleum trap types in west coast basins

Assessment region	Petroleum trap types
Queen Charlotte	
Cretaceous	simple compressional anticline, structural complex subthrust fault (rift blocks)
Miocene	simple compressional anticline, faulted anticline (fault-related rollover), thrust fault (drag closure), tilted fault block, subcrop unconformity, onlap unconformity, alluvial fan against fault scarp, porosity/permeability pinchout
Pliocene	simple compressional anticline, faulted anticline (reverse fault), subcrop unconformity
Georgia	
Cretaceous	simple compressional anticline, faulted anticline (fault-related rollover), normal fault, thrust fault (drag closure), porosity/permeability pinchout, subcrop unconformity
Tertiary	simple compressional anticline, faulted anticline (fault-related rollover), normal fault, thrust fault (drag closure), porosity/permeability pinchout, subcrop unconformity
Pleistocene	porosity/permeability pinchout
Tofino	
Tertiary	simple compressional anticline, faulted anticline (fault-related rollover), normal fault, thrust fault (drag closure), shale diapir, porosity/permeability pinchout

Based on seismic mapping and outcrop information and related extrapolations into limited-data areas, the number of structural traps alone within the assessment region is estimated to be in the hundreds. The largest structural closures involve Neogene strata within Pliocene folds, some of which exceed 50 square kilometres in area.

Source rocks

Good to excellent hydrocarbon source rocks have been identified in Upper Triassic–Lower Jurassic Kunga and Maude strata (Fig. 8), from analyses of outcrop and shallow onshore corehole samples (Macauley, 1983; Vellutini and Bustin, 1991a). Upper Kunga limestones and thin-bedded argillites and lower Maude shales contain oil-prone Type I and oil-and gas-prone Type II organic matter, with total organic content (TOC) averaging 1 to 4% in sections up to several hundred metres thick. Organic-rich shales with 5 to 10% TOC occur in beds up to 10 m thick. Measured hydrocarbon yields from organic-rich beds from the central Queen Charlotte Islands area are up to 50 to 100 mg HC/g rock, indicating excellent oil source potential (Macauley, 1983). The subsurface distribution of Kunga–Maude strata is largely unknown but is expected to be highly irregular, because of varying effects of episodic Middle Jurassic to Tertiary erosion. Cretaceous uplift and erosion was probably widespread in areas close to or landward (east) of the Hecate Basin margin (Fig. 2). Kunga–Maude strata are most likely preserved in greatest abundance in the southwestern half of the region, beneath Graham Island and western parts of Dixon Entrance, Hecate Strait and Queen Charlotte Sound (Thompson et al., 1991; Lyatsky and Haggart, 1993).

Sedimentary strata within the Upper Jurassic–Cretaceous succession contain Type III (gas-prone) organic matter, with generally poor hydrocarbon source potential (TOC less than 1%; Vellutini and Bustin, 1991a). In offshore areas, carbonaceous beds and coal seams in nonmarine Upper Cretaceous strata may have some gas potential (Fig. 8).

The Neogene Skonun Formation and unnamed upper Paleogene strata (Fig. 8) contain coal beds and dispersed Type III organic matter, with good gas and fair to good oil source potential (Bustin et al., 1990; Vellutini and Bustin, 1991a). Organic content in Skonun strata averages 0.5 to 1.5% TOC, with higher TOC values (5 to 25%) occurring in coal-bearing zones. Coal beds are abundant in the northern half of the Queen Charlotte Basin, where nonmarine deposits are thick and widespread. Neogene coal and carbonaceous beds locally contain resinite (fossil tree sap), a potential source of oil and condensate in otherwise gas-prone strata (Snowdon et al., 1988). Skonun shales and siltstones locally contain Type II organic matter, with up to 2.5% TOC, with good oil and gas source potential (Vellutini and Bustin, 1991a). Overall, Tertiary strata are lower in source rock quality than Kunga–Maude rocks, but occur in greater volume and distribution.

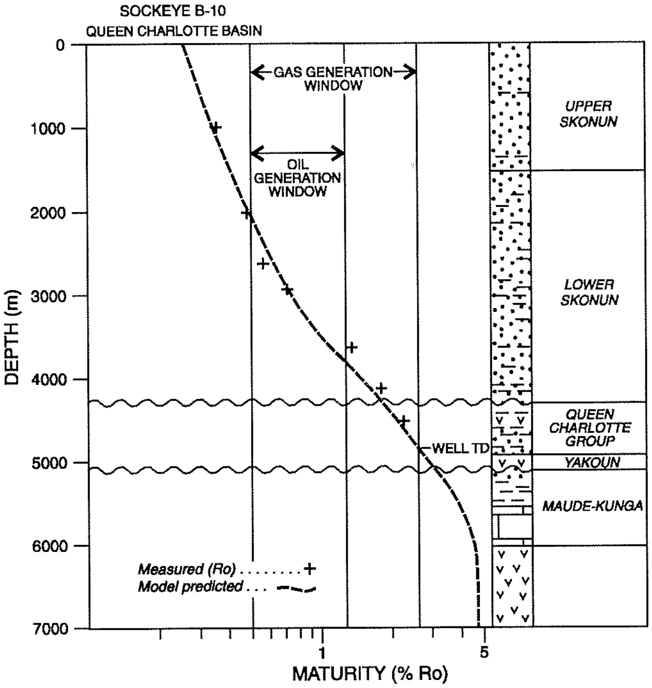

Figure 10. **Maturation–depth profile of strata in the Sockeye B-10 location, Queen Charlotte Basin (see Fig. 2 and Table 1 for well location). Mesozoic stratigraphy below well TD has been inferred from seismic data and onshore geology. Measured maturation values from Yorath and Hyndman (1983) and Bustin et al. (1990), the latter as vitrinite reflectance equivalent of pyrolysis TMAX data. Model-predicted maturation profile based on illustrated stratigraphy and heat-flow model depicted in Figure 14. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995).**

Source rock maturation

Present-day thermal maturation conditions of Mesozoic and Tertiary strata are known from pyrolysis TMAX data (Bustin et al., 1990), vitrinite reflectance measurements (Vellutini and Bustin, 1991b) and conodont alteration indices (Orchard and Forster, 1991) from outcrop and well samples. For the following discussion (and Figs. 10, 11), oil and gas windows are defined by vitrinite reflectance levels of 0.5 to 1.3% Ro and 0.5 to 2.6% Ro, respectively. References to mature source rocks imply oil window maturation levels for Kunga–Maude strata (Types I-II organic matter) and gas window maturation levels for Cretaceous and Tertiary strata (Type III organic matter).

Kunga–Maude rocks are overmature on the southwestern Queen Charlotte Islands, because of proximity to Jurassic and Tertiary plutons and dyke swarms (Orchard and Forster, 1991). In contrast, Kunga–Maude strata are marginally mature to mature on the central and northern Queen Charlotte Islands, reflecting reduced effects of magmatic heating (Vellutini and Bustin, 1991b). Maturation levels of Kunga–Maude strata in offshore areas are unknown, but are expected to vary from mature to overmature. As examples, measured and model-predicted maturation profiles for two offshore wells (Sockeye B-10 and E-66; Figs. 10, 11) indicate that Kunga–Maude strata, if present below well drill-depths, will be overmature at the B-10 location (Fig. 10) and mature to overmature at the E-66 location (Fig. 11). Model-predicted maturation differences in Mesozoic strata in the two Sockeye wells reflect differences in burial depths (Figs. 10, 11). For the Sockeye area and probably many parts of central Hecate Strait, these maturation trends indicate

Kunga–Maude sections will be within the oil window at depths above 3000 m. For other offshore areas, including Queen Charlotte Sound, subsurface well data are insufficient to estimate maturation levels for Kunga–Maude strata.

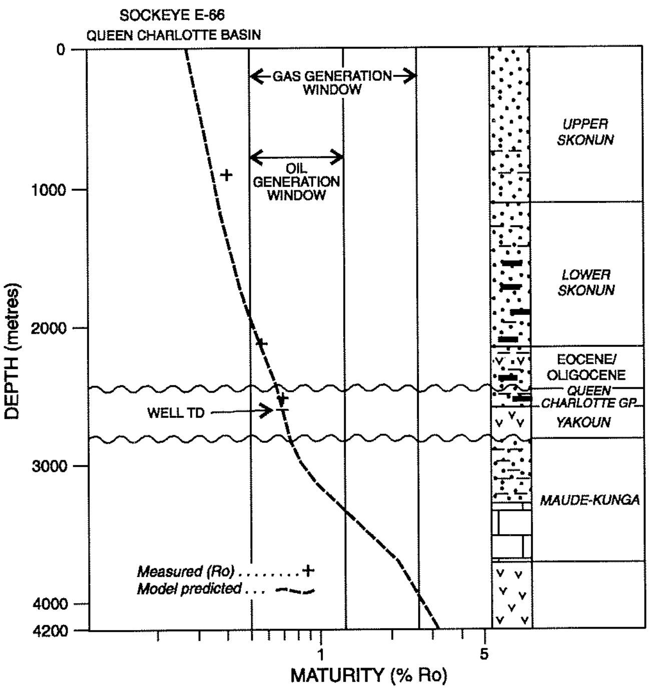

Figure 11. **Maturation–depth profile of strata in the Sockeye E-66 location, Queen Charlotte Basin (see Fig. 2 and Table 1 for well location). Mesozoic stratigraphy below well TD has been inferred from seismic data and onshore geology. Measured maturation values are vitrinite reflectance equivalent of pyrolysis TMAX data. Model-predicted maturation profile based on illustrated stratigraphy and heat-flow model depicted in Figure 14. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995).**

Neogene strata within the Queen Charlotte Basin are immature to mature, with an estimated 30 to 40 per cent of the total basin fill occurring at maturation levels within oil or gas generation windows. The depth to the top of the hydrocarbon generation window (0.5% Ro) in Neogene strata occurs typically at 2000 to 2500 m. In the Sockeye B-10 well, coal-bearing Skonun strata are mature from depths of about 2000 m to the base of the formation at 4300 m; the base of the oil window occurs at about 3700 m (Fig. 10). Skonun strata are marginally mature at the base of the Sockeye E-66 well (Fig. 11). Other offshore wells exhibit similar depth-maturation trends in Neogene Skonun strata (R.M. Bustin, pers. comm., 1993).

Timing of hydrocarbon generation

Maturation of source rock within the Queen Charlotte Basin region was controlled to varying degrees by heat flow associated with Jurassic and Tertiary magmatism, and Late Tertiary rifting and subsidence. Temporal and spatial variations in heat flow resulted in substantial variability in timing of source rock maturation and hydrocarbon generation across the region. Time-temperature modelling of stratigraphic sections from different parts of the Queen Charlotte Islands (Vellutini and Bustin, 1991b) indicates Kunga–Maude strata entered the oil generation window at various times from Late Jurassic to Late Miocene, with a general geographic trend to younger times for oil generation onset in the central and the northeastern parts of the archipelago. This reflects greater distances from plutonic and volcanic centres. Paleogene sedimentary strata entered the oil window in the Pliocene in the western Graham Island area (wells 1, 2 and 3, Fig. 2). With the exception of the deepest part of the Tow Hill well (well 5 of Fig. 2, Table 1), Neogene strata penetrated by onshore wells along eastern Graham Island (wells 4, 6-10) have yet to enter the oil window.

Similar variations in maturation history and timing of hydrocarbon generation occurred offshore. As part of this study, subsidence and hydrocarbon generation models were calculated for a number of different offshore locations, using known or interpreted stratigraphy from well and seismic data. Two of the models (Figs. 12, 13) serve to illustrate how timing of hydrocarbon generation from Kunga–Maude and Skonun source rock units may have varied within a local area. The first model (Fig. 12) is based on the Sockeye B-10 well location, where 4500 m of Miocene strata unconformably overlie Mesozoic rocks (Fig. 10). The second model is based on a seismically defined location near the Sockeye E-66 well (Fig. 13) where 2000 m of Neogene strata unconformably overlie the flank of a Mesozoic fault block. The heat-flow history (Fig. 14) used for hydrocarbon generation modelling was derived by iteratively matching kinetic model-calculated and observed maturation conditions in the Sockeye B-10 well, the deepest well in the region (Fig.10). The best-fit heat-flow model was temporally variable, with a critical thermal control on maturation being associated with a late Tertiary period of rifting and high heat flow (Fig. 14). The Sockeye area hydrocarbon generation models (Figs. 12, 13) derived from this heat-flow model illustrate dramatically different results. The Sockeye B-10 model indicates hydrocarbon generation occurred from middle Jurassic to earliest Miocene time in Kunga–Maude strata and from early Miocene to Recent time in lower Skonun strata. In contrast, the Sockeye E-66 model (10 km from Sockeye model B-10) indicates Kunga–Maude hydrocarbon generation from early Miocene to Recent time and no Skonun hydrocarbon generation. These hydrocarbon generation models, and others not illustrated here, indicate the potential for a variable and complex hydrocarbon charge history, even within local areas.

Hydrocarbon shows

The potential for significant petroleum accumulations in the Queen Charlotte Basin region is perhaps best demonstrated by the common occurrence of oil and gas shows. Over 50 sites of oil, tar, or natural gas seeps have been identified on the Queen Charlotte Islands (Hamilton and Cameron, 1989). Most of the surface seeps occur in Cretaceous and Tertiary volcanic and sedimentary rocks, many of which are in the Masset Formation. Geological and geochemical studies indicate the seeps are migrated conventional oils, sourced from both Jurassic (Kunga–Maude) and Tertiary sedimentary strata (Fowler et al., 1987; Hamilton and Cameron, 1989). One of the more areally extensive surface oil seeps occurs in Masset volcanic rocks and fractured Cretaceous shales at Lawn Hill on the southeast coast of Graham Island (Fig. 1). The geology and geochemistry of the Lawn Hill seeps indicate the hydrocarbons were probably sourced from underlying or subjacent Jurassic rocks, with migration into the host rocks in late Neogene time (Snowdon et al., 1988; Hamilton and Cameron, 1989). The Lawn Hill area is part of a high-standing block within the westernmost Queen Charlotte Basin. Cretaceous or Neogene reservoir strata in surrounding or basinward areas may be highly prospective for conventional accumulations of similar oils.

Subsurface hydrocarbon shows were encountered in several petroleum and mineral exploration wells, including gas flows from the Tian Bay well (Hamilton and Cameron, 1989), oil staining in Tertiary volcanic rocks in the Port Louis and Naden wells (Union Oil Company, 1971; Bow Valley Industries, 1984), oil staining in Cretaceous sandstones in the Queen Charlotte well (Royalite Oil, 1949), and oil staining in Neogene sandstones in the Tow Hill and Sockeye B-10 wells (Richfield Oil Corporation, 1958; Shell Canada, 1968b). The best subsurface hydrocarbon show was encountered in the Sockeye B-10 well, which penetrated 40 m of live-oil-stained Miocene sandstones. Geochemical analysis (gas chromatography–mass spectrometry) of a saturate fraction from the Sockeye oil show indicated the presence of a biomarker compound diagnostic of Jurassic Kunga Group rocks (M. Fowler, pers. comm., 1991). The same biomarker compound is indicated in similar analyses of Kunga outcrop samples from the Queen Charlotte Islands. Other geochemical characteristics of the Sockeye oil show indicate a probable derivation from carbonate rocks. The recognition of a probable Jurassic Kunga source for the Sockeye oil show is an important finding that links the region's principal source and reservoir rocks. The modelled timing of Kunga hydrocarbon generation for the Sockeye area (Figs. 12, 13) suggests the oil may have migrated laterally into the Sockeye structure, a Late Pliocene inversion anticline, (Fig. 6) from an adjacent Mesozoic fault block. Kunga source rocks are overmature beneath the B-10 well location, but may be mature in surrounding area (Figs. 10, 11).

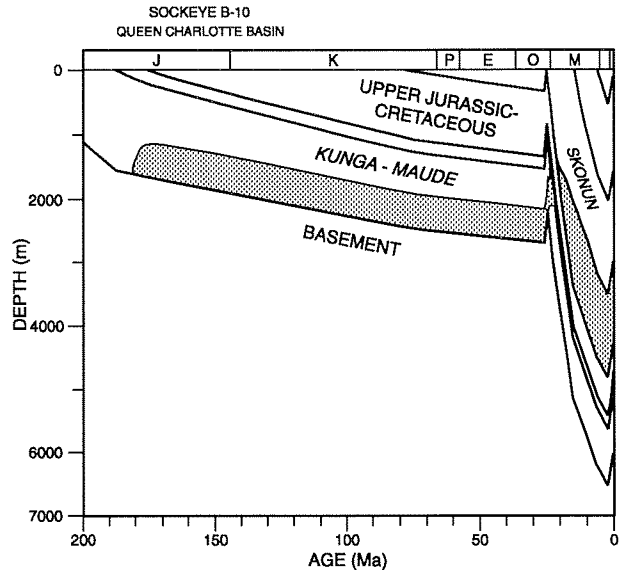

Figure 12. Subsidence and hydrocarbon generation model for the area of Sockeye B-10 well, central Hecate Strait, Queen Charlotte Basin. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995). Hydrocarbon generation models based on standard (BasinMod) kinetic parameters for organic matter types (Types I–II in Kunga–Maude strata and Type III in Skonun strata). See Figure 14 for heat-flow input of this model. See text for discussion.

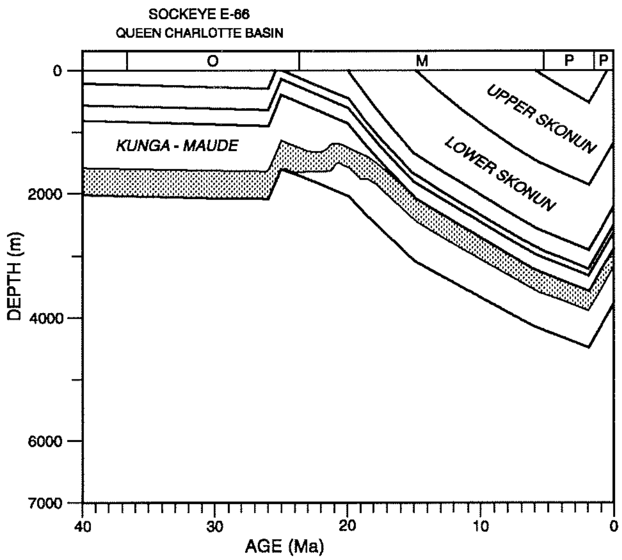

Figure 13. Subsidence and hydrocarbon generation model for the area of Sockeye E-66 well, central Hecate Strait, Queen Charlotte Basin. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995). Hydrocarbon generation models based on standard (BasinMod) kinetic parameters for organic matter types (Types I–II in Kunga–Maude strata and Type III in Skonun strata). See Figure 14 for heat-flow input of this model. See text for discussion.

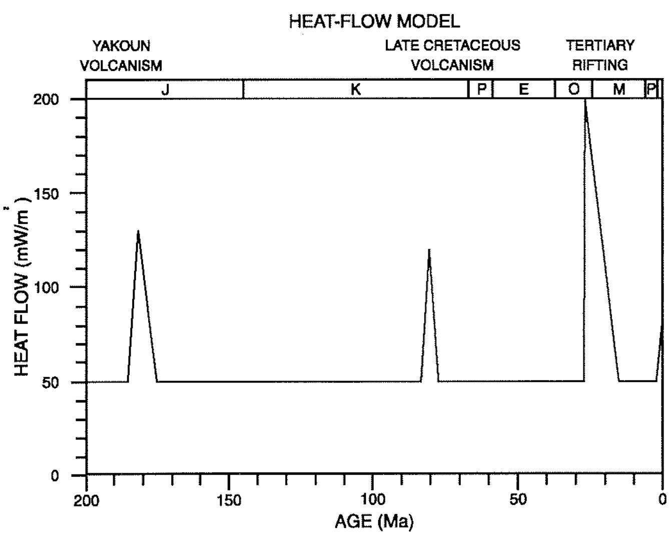

Figure 14. Heat-flow model for central Hecate Strait, Queen Charlotte Basin (input for hydrocarbon generation models of Figs. 12, 13). Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995).

The Sockeye B-10 well also encountered numerous shows of gas-cut mud in coal-bearing zones in Skonun and Cretaceous strata below 3000 m depth (Fig. 10).

Offshore subsurface gas accumulations are inferred to be directly indicated in marine seismic reflection data. Shallow gas in upper Neogene and Quaternary strata have been inferred in many locations beneath Hecate Strait, from acoustic anomalies on high resolution seismic profiles (Barrie, 1988). Indications of possible deep gas accumulations in Neogene strata have been identified on conventional seismic profiles, in several offshore locations (Dietrich, 1995). One such example (star in Fig. 6), illustrates a possible direct hydrocarbon indicator as a subhorizontal, low-frequency reflection at the crest of a fault-bound structure. The direct hydrocarbon indicators occur at a stratigraphic level similar to the Sockeye B-10 well show (Dietrich, 1995).

Petroleum assessment

The West Coast petroleum assessment was undertaken in order to provide quantitative estimates of total oil and gas potential and possible sizes of undiscovered fields in the region. Petroleum assessments of basins or regions are usually based on analyses of a number of exploration plays. The Queen Charlotte assessment involved analysis of three, regional-scale conceptual plays. Based on considerations of source rock types and hydrocarbon shows, all of the Queen Charlotte plays were considered to have both oil and gas resource components. Appendix I lists all input data used for statistical analysis for each play. Probability distributions of reservoir parameters and marginal probabilities for prospect and play level risks are tabulated.

Petroleum plays

Queen Charlotte Cretaceous oil and gas play

Play definition. This oil and gas play involves all structures and prospects within Cretaceous strata beneath and adjacent to Queen Charlotte Basin. The Cretaceous play area encompasses most of the Queen Charlotte Islands and adjacent shelf areas, extending as far east as the Hecate Basin margin (Figs. 2, 15).

Geology. Potential hydrocarbon traps involve Cretaceous sandstones, principally within the basal units of the Queen Charlotte Group, in fault block or anticlinal structures (Table 3). Onshore areas have been mapped where Cretaceous reservoir strata directly overlie Kunga–Maude source rocks (Thompson et al., 1991), an optimum stratigraphic relationship that probably occurs in some fault blocks in the subsurface. The most prospective part of the play area occurs in a southeast-trending fairway from central Graham Island to southwestern Queen Charlotte Sound, an area where the main reservoir facies was deposited (Fig. 15). The play includes areas (such as Graham Island) where potential reservoir strata underlie thick Tertiary volcanic rocks. This play is characterized by relatively small structures and single reservoir zones.

Exploration risks. All of the Queen Charlotte plays are believed to have a high probability of existing (i.e., low play risk). However, within each play, risks associated with individual prospects are considered high. A major prospect-level risk in all Queen Charlotte plays is the possible local absence of or inadequate maturation conditions for source rocks (Appendix I, Tables I.1-6b). In addition, a significant risk factor associated with Cretaceous prospects, in particular, is the possible absence of adequate reservoir facies (Appendix I, Tables I.1,2b). The subsurface distribution and reservoir characteristics of Cretaceous strata are expected to be erratic, with little subsurface control currently available. Prospects involving Cretaceous

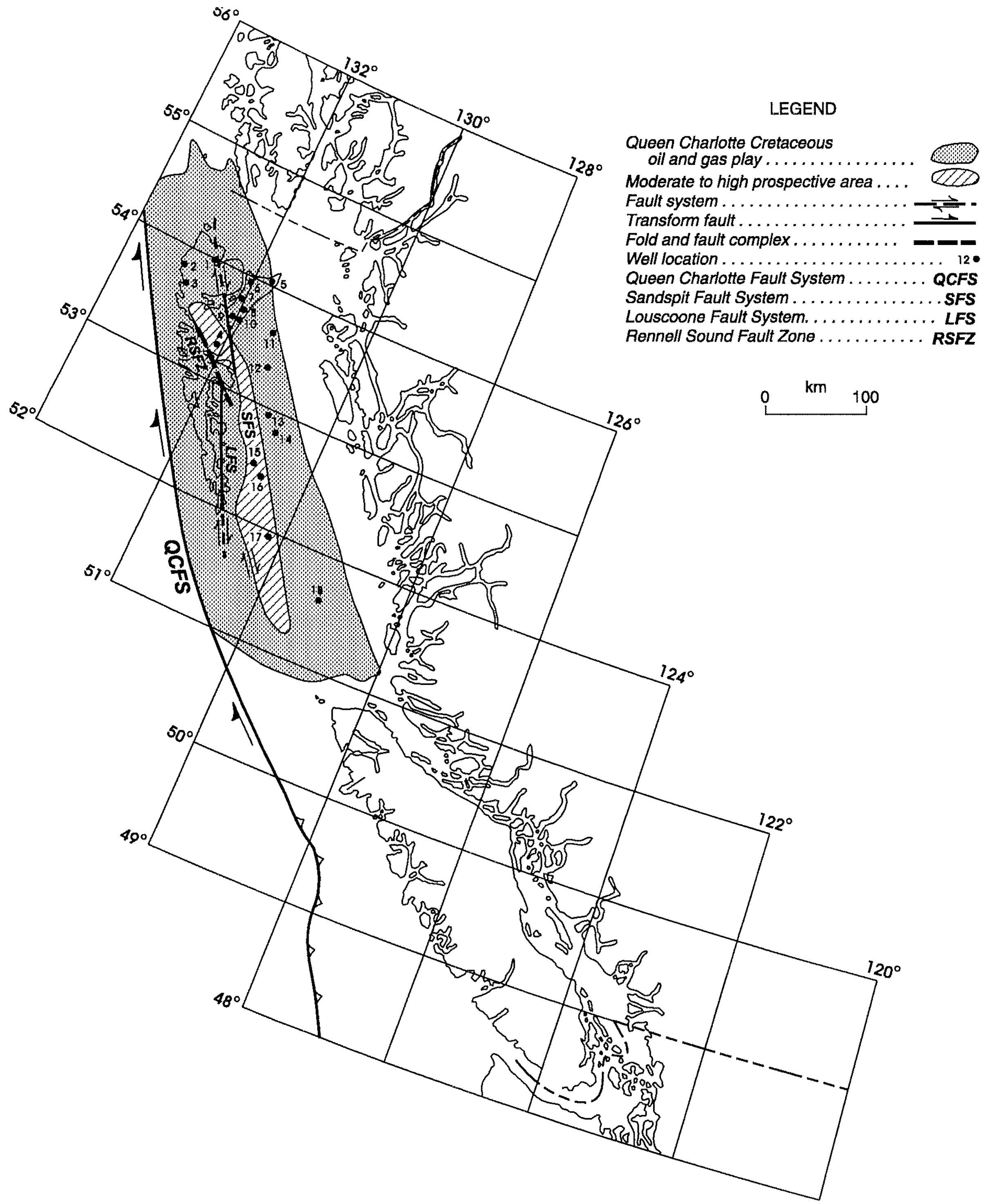

Figure 15. Queen Charlotte Cretaceous oil and gas play area. Major structural elements are illustrated. Area of moderate to high prospectivity is depicted and discussed in text.

strata may be difficult to map seismically in areas (such as Graham Island) where overlying Masset volcanic rocks are thick and extensive. Assigned exploration risk for Cretaceous plays are 0.11 for oil and 0.09 for gas, with a significant component of the risk associated with the presence of reservoir facies. These exploration risks imply that oil and gas accumulations will occur in about 11 per cent or 9 per cent (respectively) of all prospects within the play.

Play potential. The Cretaceous play is characterized by numerous, small, structurally complex prospects and reservoir zones. This play has an estimated in-place median oil potential of 392 million m^3 (Fig. 16). The mean value of the number of predicted fields is 62. The largest undiscovered field is expected to contain 96 million m^3 of oil (median value). Potential for the Cretaceous gas play is 75 billion m^3 (median in-place value) (Fig. 17). The estimate assumes a total field population of 50 (mean value), with the largest undiscovered field having an initial in-place volume of 21 billion m^3 of natural gas (see Table 4 for listing of plays, mean and median of potential, and median of the largest pool size).

Queen Charlotte Miocene oil and gas play

Play definition. Neogene strata within the Queen Charlotte Basin were assessed in two plays, each play with an oil and gas component, differentiated on the basis of trap type and timing of trap formation (Miocene and Pliocene plays). The Miocene oil and gas play occurs basinwide in an area of about 40,000 km^2 and involves all extensional structure and stratigraphic traps found within Neogene strata that developed during the transtensional phase of basin development (Fig. 18).

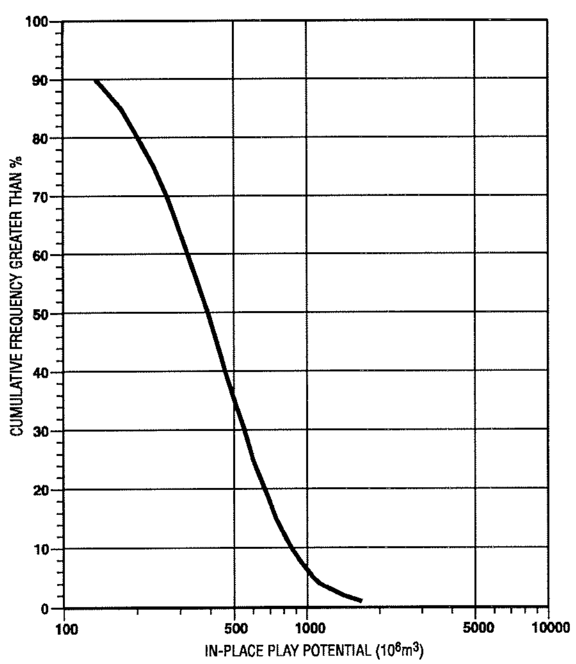

Figure 16. Estimate of in-place oil potential of the Cretaceous play in Queen Charlotte Basin. Median value of probabilistic assessment is 392 million m^3 of in-place oil distributed in 62 fields.

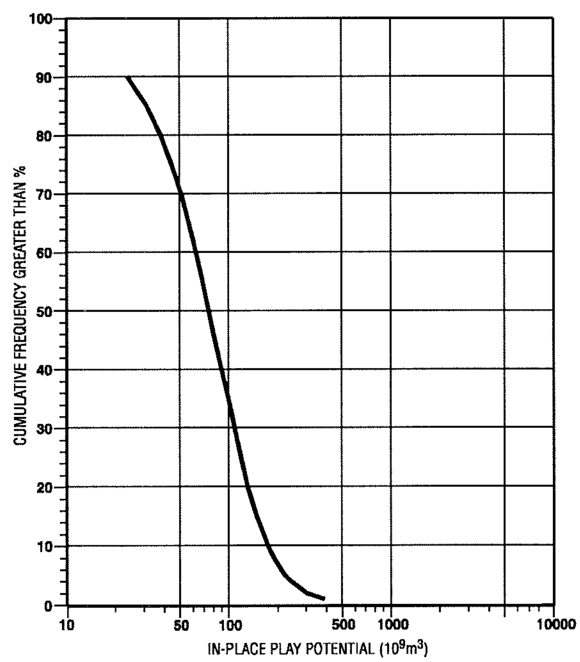

Figure 17. Estimate of in-place gas potential of the Cretaceous play in Queen Charlotte Basin. Median value of probabilistic assessment is 75 billion m^3 of in-place gas distributed in 50 fields.

Table 4: Oil and gas potential in Queen Charlotte, Georgia, and Tofino regions (O=oil; G=gas)

Play name	Expected no. of fields (mean)	Median play potential (in-place) (million m^3)	Mean play potential (in-place) (million m^3)	Median of largest field size (in-place) (million m^3)
Queen Charlotte Region				
Cretaceous oil	62	392	478	96
Cretaceous gas	50	75,435	94,336	20,675
Miocene oil	28	574	668	165
Miocene gas	40	285,710	317,080	71,190
Pliocene oil	13	398	652	233
Pliocene gas	30	321,750	389,710	95,774
Total	103 (O); 120 (G)	1559.8 (O); 733,760 (G)		
Georgia Region (gas only)				
Georgia Pleistocene stratigraphic	92	207	217	10
Georgia Tertiary structural	93	59,329	65,483	9803
Georgia Cretaceous structural	45	118,500	146,780	31,977
Total	230	185,150		
Tofino Region				
Tofino Tertiary structural	41	266,003	266,590	25,982
Total	41	266,003		
Total West Coast basins	103 (O); 283 (G)	1559.8 (O); 1,228,300 (G)		

Geology. Prospects involve Miocene sandstones and conglomerates and structural or stratigraphic traps. Structural traps include tilted fault blocks, fault-related rollover and drag features and drape anticlines (Table 3). Potential stratigraphic traps are associated with intra-Tertiary unconformities (onlap or subcrop), and updip pinchouts within half-grabens and against fault scarps (Table 3). The Tertiary plays incorporate areas or structures where reservoir strata are in direct stratigraphic or structural contact with Mesozoic rocks, providing favourable conditions for local hydrocarbon charging from Kunga–Maude source rocks.

Exploration risks. Along with the significant risk attached to all Queen Charlotte plays concerning inadequate maturation conditions of source rocks, there is a significant risk in the Miocene play associated with the inadequacy of seal (Appendix I, Tables I.3,4b). Neogene structures are commonly faulted and shallow parts of many northern sub-basins contain high percentages of permeable sandstone. The Miocene play is assigned an exploration risk of 0.10 for oil and 0.15 for gas, with most of the risk associated with source rock, presence of closure, and seal (Appendix I, Tables I.3,4b).

Play potential. Estimates of the potential for the Miocene oil play show a median in-place volume of 574 million m^3 distributed in 28 fields (mean value) (Fig. 19, Table 4). The largest undiscovered oil field is predicted to contain 165 million m^3 (median value). The Miocene gas play predicts a mean value of

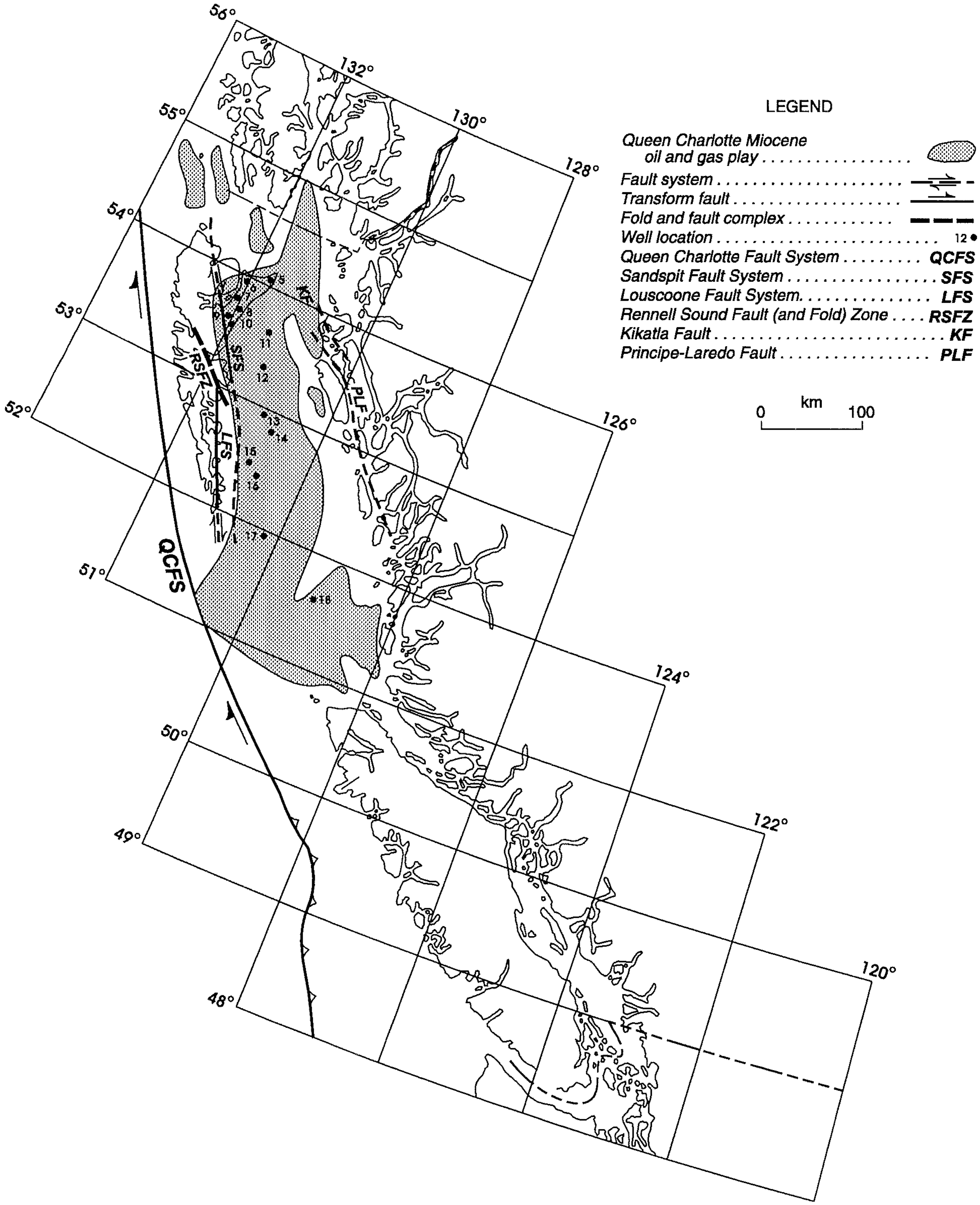

Figure 18. Queen Charlotte Miocene oil and gas play area. Major structural elements are illustrated.

40 fields with a median in-place potential of 286 billion m^3 (Fig. 20, Table 4). The largest estimated gas field is 71 billion m^3 (median in-place volume).

Queen Charlotte Pliocene oil and gas play

Play definition. This petroleum play includes all structural traps in Neogene reservoirs formed during contractional deformation associated with late Pliocene transpression. The play area is restricted to the northern half of the Queen Charlotte Basin (Fig. 21).

Geology. Similar to the Miocene play, Skonun sandstones and conglomerates constitute the principal reservoir in the Pliocene petroleum play. The Pliocene play is differentiated from the Miocene play on the basis of structural style and timing of trap development. Pliocene structures include large-amplitude folds and faulted anticlines (flower structure) (Rohr and Dietrich, 1992) (Table 3). Many of the Pliocene antiforms are structurally detached from underlying Mesozoic rocks. In comparison to Miocene prospects, the Pliocene prospects are generally larger in area and involve thicker (multi-zone) reservoir sections. Like the Miocene play, the Pliocene play includes many prospects where reservoir strata are in direct structural contact with Mesozoic rocks, which locally include Kunga–Maude source units.

Exploration risks. The major prospect-level risk in the Pliocene play is associated with source rock (Appendix I, Tables I.5,6b). A source rock timing risk of particular significance to Pliocene prospects is the

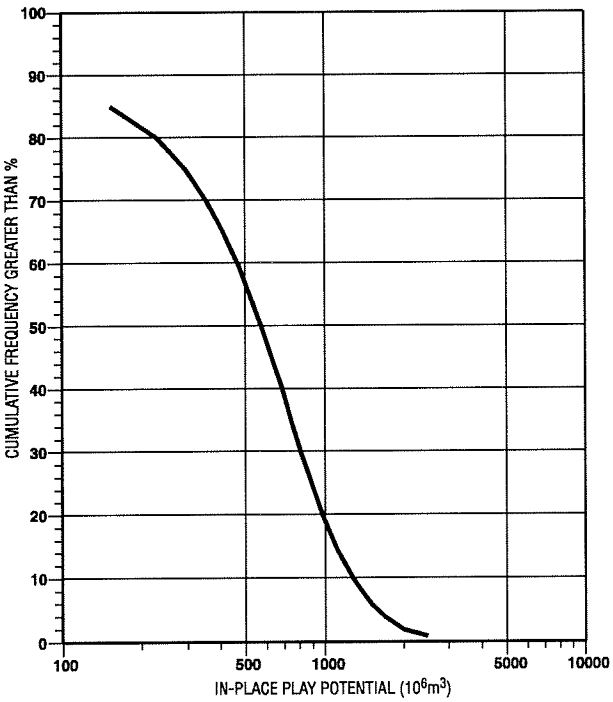

Figure 19. Estimate of in-place oil potential of the Miocene play in Queen Charlotte Basin. Median value of probabilistic assessment is 574 million m^3 of in-place oil distributed in 28 fields.

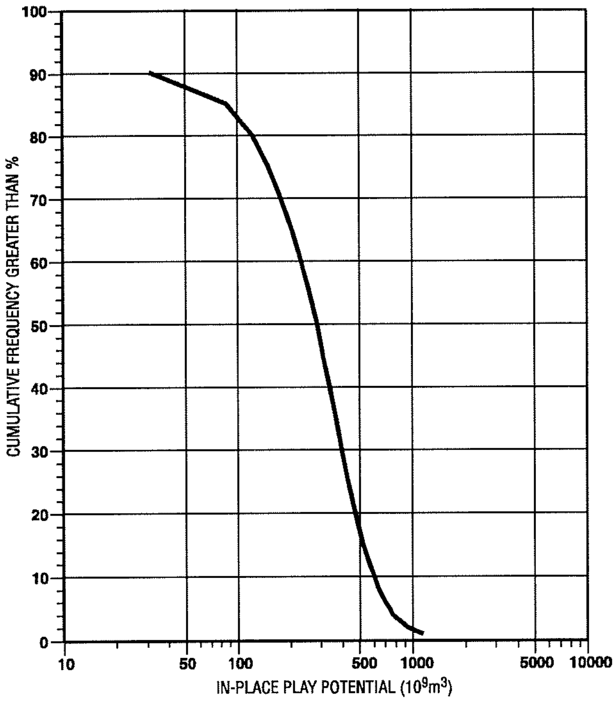

Figure 20. Estimate of in-place gas potential of the Miocene play in Queen Charlotte Basin. Median value of probabilistic assessment is 286 billion m^3 of in-place gas distributed in 40 fields.

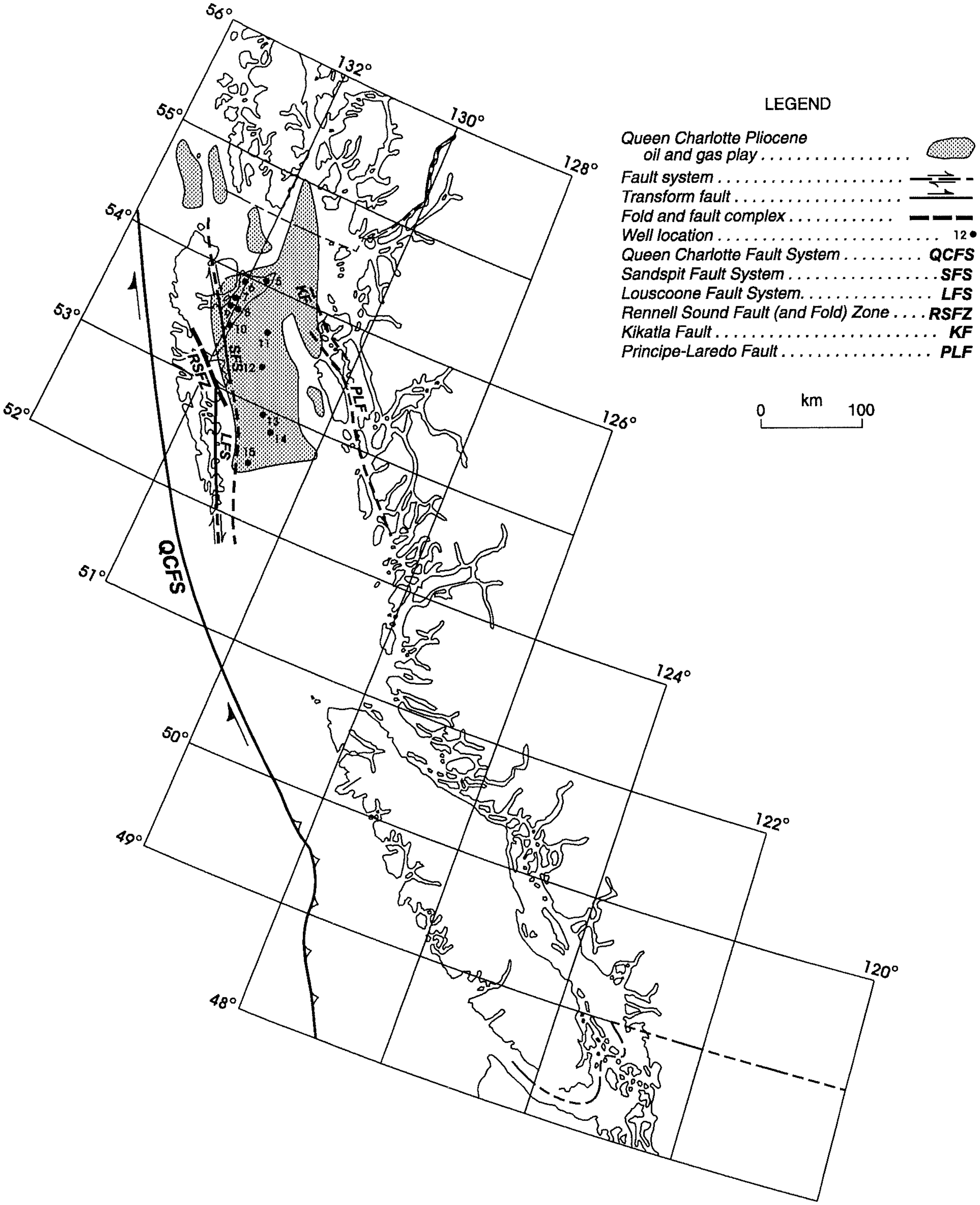

Figure 21. Queen Charlotte Pliocene oil and gas play area. Major structural elements are illustrated.

possibility that Kunga–Maude oil generation and migration occurred prior to late Pliocene trap formation. Another significant assigned risk factor is the inadequacy of seal. Many Pliocene prospects are extensively faulted (hydrocarbon leakage possibility) or involve stratigraphic sections with high percentages of permeable sandstone.

The Pliocene play has an exploration risk of 0.07 for oil and 0.16 for gas, with the most significant risk components associated with adequacy of source rocks and seals. The difference in oil and gas risk factors reflects the greater uncertainty for the presence of oil source rocks.

Play potential. The Pliocene play has a median oil potential of 398 million m^3 distributed in 13 fields (in-place volume) (Fig. 22, Table 4). The largest undiscovered field has a predicted volume of 233 million m^3 of oil (median value). The predicted median gas resource within the Pliocene play is 322 billion m^3, in 30 fields (Fig. 23, Table 4). A median value of 96 billion m^3 of gas is predicted for the largest field.

Discussion of assessment results

Resource potential. Median estimates of total petroleum potential for the Queen Charlotte Basin region (from all plays) are 1.56 billion m^3 (9.8 Bbbl) of in-place oil and 734 billion m^3 (25.9 Tcf) of in-place gas (Table 4; Figs. 24, 25) (Note that the total median estimates for assessment regions are not derived arithmetically by adding together the median hydrocarbon potentials of individual plays. These numbers are summed using statistical techniques). High confidence (90% probability) and speculative (10% probability) estimates of total oil potential are 657 and 3088 million m^3 (6.3 and 19.4 Bbbl), respectively. High confidence and speculative estimates of gas potential are 338 and 1351 billion m^3 (12 and 48 Tcf), respectively (Figs. 24, 25). Individual field-size estimates display similar probability-dependent variations. The wide range of estimates of total potential and field sizes are typical of frontier region assessments and reflect the geological uncertainties in quantifying lightly explored or conceptual exploration plays.

Resource distributions. The highest oil potential (volume) occurs in the Miocene play and highest gas potential in the Pliocene play (Table 4). The largest individual oil and gas fields are predicted to occur in the Pliocene play, with median size estimates of 233 million m^3 (1466 Mbbl) of in-place oil and 96 billion m^3 (3.3 Tcf) of in-place gas. Field size rankings for all plays suggest that about 60 per cent of the region's total petroleum resource is expected to occur in the five largest oil and gas fields. This resource distribution indicates a moderately concentrated hydrocarbon habitat, typical of large convergent and transform plate margin basins (Klemme, 1984).

The assessment results indicate the Neogene Queen Charlotte Basin is expected to contain about 80 per cent of the region's total petroleum resource volume and nine of the ten largest fields, a concentration reflecting the greater abundance and quality of reservoirs within the Neogene Skonun Formation. In terms of general geographic areas within the basin, southern Hecate Strait is considered the most prospective, followed, in order, by the Queen Charlotte Sound, eastern Graham Island, northern Hecate Strait, and Dixon Entrance areas (Figs. 1, 2). The high potential for the southern Hecate Strait area reflects the optimum combination of abundant Neogene reservoir strata, numerous large structures, and presence of Neogene and, at least locally, Jurassic source rocks. Outside the Queen Charlotte Basin margins, the western Graham Island and adjacent shelf areas have some potential in Cretaceous and to a lesser extent, Paleogene prospects. Very little or no petroleum potential is expected in the onshore and inter-island areas of the southern Queen Charlotte Islands and adjacent Pacific continental shelf, because of limited distribution of reservoir strata and the overmature source rocks (Dietrich et al., 1992).

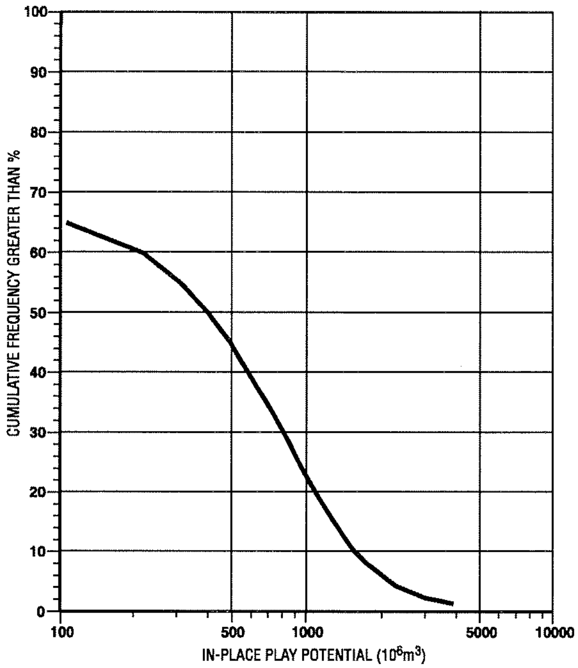

Figure 22. Estimate of in-place oil potential of the Pliocene play in Queen Charlotte Basin. Median value of probabilistic assessment is 398 million m^3 of in-place oil distributed in 13 fields.

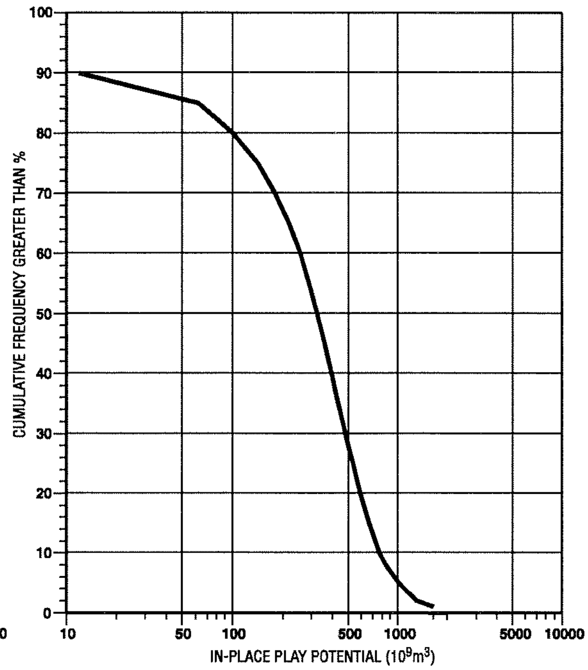

Figure 23. Estimate of in-place gas potential of the Pliocene play in Queen Charlotte Basin. Median value of probabilistic assessment is 322 billion m^3 of in-place gas distributed in 30 fields.

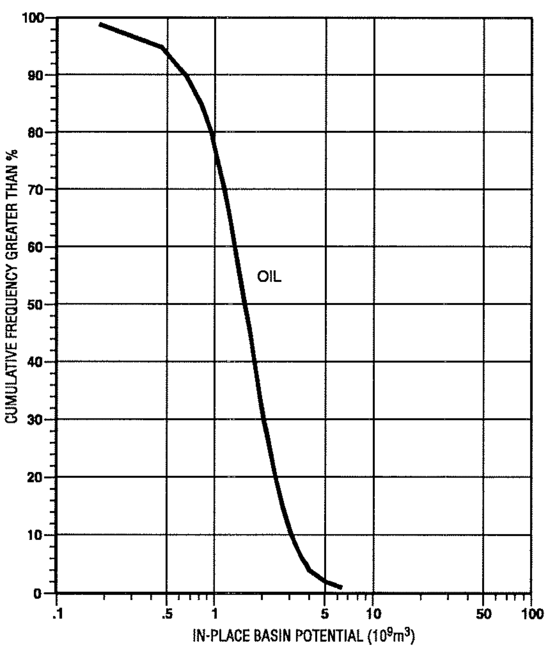

Figure 24. Estimate of total oil potential for the Queen Charlotte Basin region. Median value of probabilistic assessment is 1.6 billion m^3 of in-place oil.

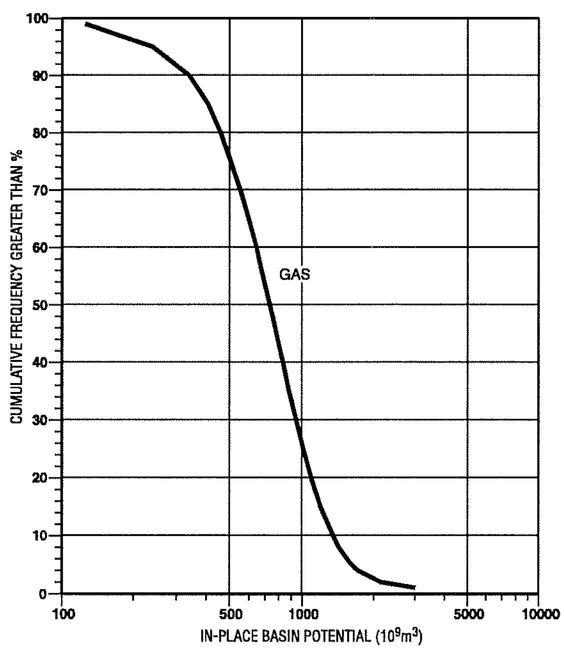

Figure 25. Estimate of total gas potential for the Queen Charlotte Basin region. Median value of probabilistic assessment is 734 billion m^3 of in-place gas.

Assessment results and exploration history. The exploration risks estimated in the assessment suggest success rates for exploratory drilling in the region should average about one in nine. The absence of discoveries in the 18 wells drilled during early phases of petroleum exploration in the Queen Charlotte Basin region may indicate a higher exploration risk than estimated here. However, many of the previous wells are considered inadequate or only partly diagnostic exploration tests. Nine of the ten onshore wells were drilled to depths of less than 2000 m, three penetrating entirely volcanic sections. Of the eight offshore wells, three were drilled as purely stratigraphic tests (Osprey, Harlequin and Auklet), three were drilled on the flanks of structures (Murrelet, Sockeye B-10 and E-66), and two tested only parts of fault-segmented anticlines (Coho and Tyee). Seismic reflection surveys used to support early exploration programs were characterized by fair or poor data quality compared to current standards. Some wells were undoubtedly drilled in less than optimum locations. Even without these considerations, 18 wells represent evaluation of only a small fraction of the total prospective area within the Queen Charlotte Basin region. Historically, the first significant hydrocarbon discovery in a frontier region is often preceded by many unsuccessful exploration wells. As examples, 36 wells were drilled in the Grand Banks region of offshore Newfoundland before the first field (Hibernia) was discovered (Sinclair et al., 1992), and 16 wells were drilled in the Cook Inlet Basin of southern Alaska before the first field (Swanson River) was discovered (Magoon and Kirschner, 1990). In the case of Cook Inlet Basin, about 15 per cent of subsequent exploration wells led to additional discoveries, an exploration success rate slightly higher than predicted for the Queen Charlotte Basin region.

GEORGIA ASSESSMENT REGION

Exploration history and regional studies

The earliest public-domain geophysical survey that encompassed the Georgia Basin region was a 1955 regional aeromagnetic study by the Geological Survey of Canada. In 1959, a gravity survey was carried out by Petcal that encompassed most of the Fraser River Valley west of Abbotsford (Petcal Company Ltd., 1959).

The first extensive seismic reflection survey was acquired by Richfield Oil Corporation in 1959. It extended from Abbotsford to the Strait of Georgia and between the Fraser River and the U. S. border (Richfield Oil Corporation, 1959a). Richfield also conducted a short seismic program in American waters off Point Roberts (Richfield Oil Corporation, 1959b). B. C. Hydro Gas Operations was interested in the potential for underground gas storage in the Lower Mainland and conducted a 322-kilometre seismic program in 1977. Conoco conducted a petroleum exploration program in the Lower Mainland in the early 1990s. About 380 km of seismic work was completed, resulting in numerous indications of structural closures and prospects. Both four-way closures and reverse fault traps were identified. Conoco also participated in a survey in the Strait of Georgia, as a result of which more prospects were identified.

South of the border, in Whatcom County, Washington State, seismic reflection work was first conducted in the early 1940s by Chevron and later in 1985 by CGG (Companie General Geophysique). In 1987, Canadian Hunter performed an extensive 160-kilometre survey in the area, identifying the structure at Birch Bay.

More than 2700 km of marine seismic data were acquired by the petroleum industry in the Strait of Georgia area in the 1960s. Canadian Superior Oil recorded approximately 245 km of gas exploder seismic data in the Strait of Georgia in 1962 (Canadian Superior Oil Ltd., 1962). British American Oil Company conducted a 1150 km-long gas exploder marine seismic survey (British American Oil Company Ltd., 1965). Texaco Exploration Canada conducted an extensive marine seismic programme in the Strait of Georgia in 1968 and 1969 (Texaco Exploration Canada Ltd., 1968, 1969) when about 300 km of marine seismic data were recorded. Two structural highs were delineated: one near Robert's Bank with an area of substantial closure, the other in central Strait of Georgia west of Vancouver. A major normal fault, paralleling the folding and down-dropped to the northeast with a throw of about 1200 m is interpreted from a reflection profile running east of Mayne Island towards Point Roberts (see Fig. 26, cross-section C-C', same fault interpreted just east of Valdes Island). On the east side of Vancouver Island, British Petroleum conducted seismic surveys totalling about 160 km. From these surveys, two wells were drilled on seismically defined structures (British Petroleum, 1987 a, b).

The first petroleum exploration wells were drilled in 1901 in Whatcom County, Washington, and in 1906 in the Fraser River valley in Canada (Johnston, 1923; McFarland, 1983). Since 1901, a total of 118 wells

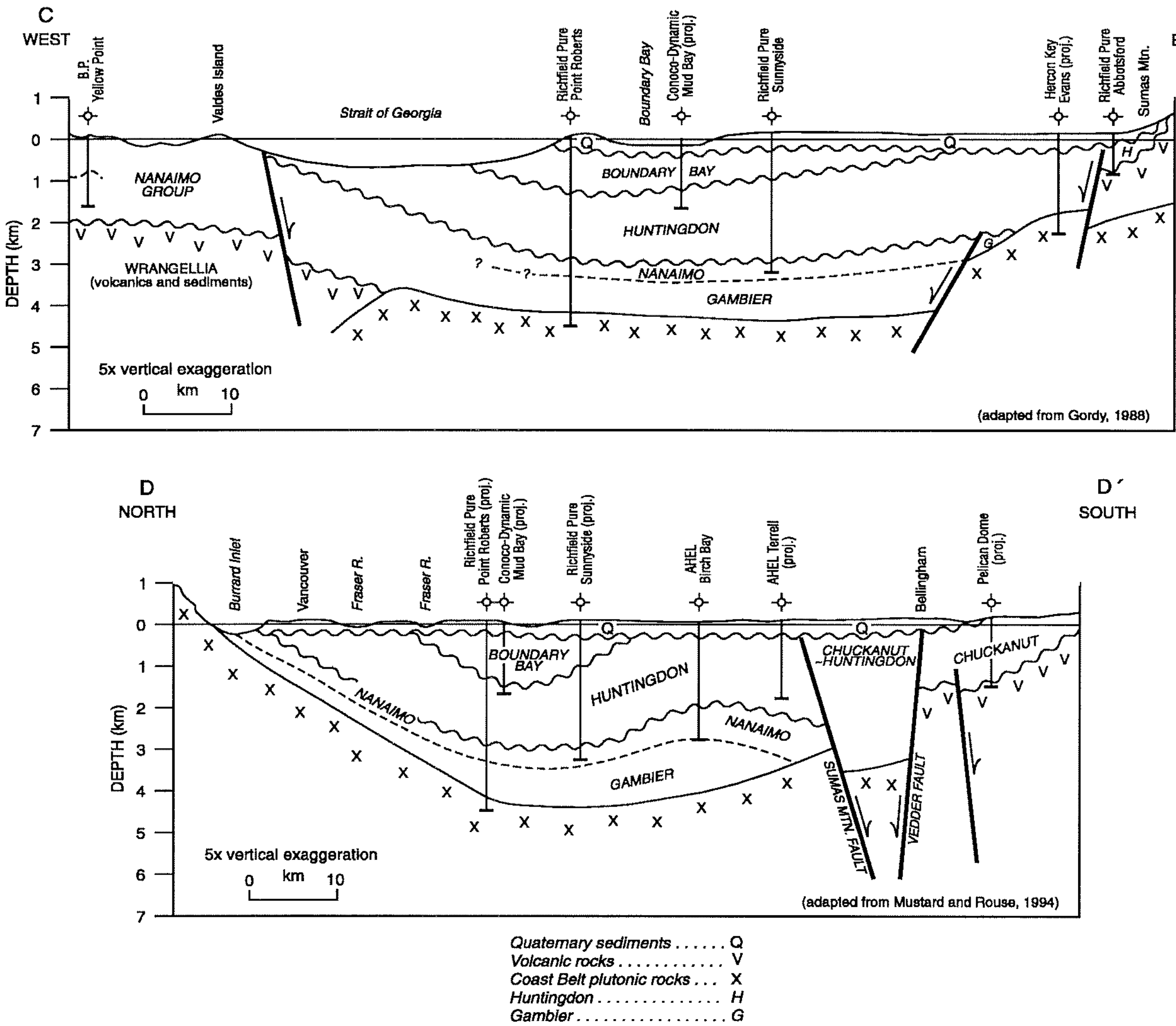

Figure 26. Geological cross-sections (derived from seismic and well data) across Strait of Georgia (**C-C'**) and parallelling the mainland coast from Burrard Inlet to Bellingham (**D-D'**; locations in Fig. 3) (modified from Gordy, 1988 and Mustard and Rouse, 1994) showing main Tertiary and Upper Cretaceous units of Georgia Basin in the area. Main faults are either projected from the surface or known from petroleum exploration seismic lines.

have been drilled for oil and gas within the Bellingham sub-basin (see Fig. 3 for well locations and Table 2 for well listings). The Bellingham sub-basin encompasses the Fraser River lowland and Whatcom County (Fig. 2). Twenty-three of these wells were completed in the lower Fraser River valley; the remaining 95 are located in Whatcom County. The vast majority of the wells are shallow (less than 300 m) and were probably originally drilled as water wells.

Most of Georgia Basin, that is, eastern Vancouver Island, Strait of Georgia, and the western portion of the Lower Mainland, is underlain by a Cretaceous sedimentary succession. Seven wells penetrated the Cretaceous succession in the area (Pacific Petroleum Ltd., 1959; Richfield Oil Corporation, 1962b, 1963; British Petroleum, 1987a, b; Hurst, 1991). The three wells drilled on the mainland penetrated Cretaceous strata underlying a thick Tertiary cover. On Vancouver Island and Saturna Island, four wells were collared in Cretaceous strata (Fig. 3, Table 2).

Regional geology

Geological setting and tectonic evolution

There has been much debate concerning the tectonic setting of Georgia Basin. Mustard (1994) speculated that the Upper Cretaceous–Tertiary Georgia Basin is a hybrid foreland and strike–slip basin that developed in response to (post-Wrangellian) terrane accretion and subduction along the Vancouver Island continental margin. The Cretaceous basin developed within a foreland tectonic setting, with significant portions of basin-fill likely derived from uplift areas to the east and southeast (Mustard, 1991, 1994). Southern parts of the basin subsequently evolved in (Tertiary) strike–slip or pull-apart tectonic regimes, with basin-fill sediments derived from multiple source areas (Johnson, 1982; Mustard and Rouse, 1994). England and Bustin (1998) designate Georgia Basin as a broad-ridged forearc basin analogous to the Great Valley forearc basin of California (Dickinson, 1976; Dickinson and Seely, 1979).

Georgia Basin occupies an area of 14,000 square kilometres in southwestern British Columbia and northwestern Washington State (Figs. 2, 3). The basin includes the Lower Fraser River area and Whatcom County as well as the Strait of Georgia and eastern Vancouver Island. There are four sub-basins within Georgia Basin. Nanaimo sub-basin encompasses the southeastern coast of Vancouver Island and adjacent Strait of Georgia as well as the Gulf Islands. Comox sub-basin is located farther north along the east-central coast of Vancouver Island and adjacent Strait of Georgia. Suquash sub-basin is located in the vicinity of Port Hardy on the northeastern shore of Vancouver Island. The Bellingham or Whatcom sub-basin includes the Fraser Delta and northwestern Washington. Upper Cretaceous to Recent sedimentary strata comprise the fill of the Georgia Basin (Figs. 8, 26).

The Upper Cretaceous and (?) lowest Tertiary Nanaimo clastic deposits in Georgia Basin represent an overlap assemblage that was eroded from rocks uplifted during terrane accretion. Monger (1991a) postulated the basin developed in a foreland setting with associated west-verging thrust faults, crustal thickening, and regional uplift of the Coast Mountains. England and Calon (1991) suggested that Nanaimo sedimentation occurred in a forearc setting related to Late Cretaceous plutonism in the Coast Mountains. Mustard (1994) interpreted a foreland basin model for the Cretaceous Georgia Basin based on recognition of Late Cretaceous thrust systems in the southern Coast Belt and northwest Cascades and syntectonic Nanaimo Group sedimentation. Recognition of multiple source areas for Cretaceous sediments, including areas to the west of the basin, suggest a foreland rather than a forearc basin setting (Mustard, 1994). England and Bustin (1998) on the other hand, interpret Georgia Basin as a forearc basin that developed between a Late Cretaceous arc in the eastern Coast Mountains and a trench or transform fault thought to be present at the time, west of Vancouver Island.

Seismic refraction profiles in the Strait of Georgia interpreted by White and Clowes (1984), indicate thickening of Cretaceous sediments to the west and no major discontinuity separating the Coast Plutonic Complex from the Insular Belt. These profiles also suggest that the Coast Range intrusives extend beneath the Cretaceous sediment layer in the Strait of Georgia.

Stratigraphy and structure

Basement rocks in Georgia Basin consist of complexly deformed assemblages of Devonian to Lower Cretaceous volcanic, plutonic and sedimentary rocks, occurring in parts of several terranes within the Insular, Coast and, in Washington, Cascade tectonic belts (Monger and Journeay, 1994; Mustard, 1994). On Vancouver Island, the Wrangellian Karmutsen Formation is up to 6000 m thick and comprises pillow basalts, breccias and massive flows (Muller, 1977). The upper part of the Karmutsen Formation is locally interbedded with carbonates of Late Triassic age (Fig. 8). The Karmutsen Formation is conformably overlain by the Quatsino Formation, which consists of 300 m of shallow-water and fossiliferous carbonates (Carlisle and Susuki, 1974). A gradational contact separates the Quatsino Formation from overlying dark siliceous and carbonaceous shales of the Parson Bay Formation. Calcareous sandstone and fine grained sandstone are lesser components of the 300 m thick Parson Bay Formation. This formation is in turn gradationally overlain by the Jurassic Harbledown Formation, a unit of thinly banded shale, siltstone and tuff about 300 m thick. The Harbledown Formation grades westward into Lower Jurassic Bonanza Group rocks; a calc-alkaline, dominantly pyroclastic volcanic assemblage with interbedded shale and siltstone. The Bonanza Group varies in thickness up to 2000 m. Comagmatic with the Bonanza Group are the Early and Middle Jurassic Island Intrusions of Vancouver Island (Muller, 1977; Isachsen et al., 1985). These intrusions are unconformably overlain by Upper Cretaceous sediments of the Nanaimo Group. A complex and composite boundary separates basement modified by tectonic, magmatic and metamorphic processes from relatively unaffected basin fill. Structures within the basement rocks include broad, northwest-aligned antiforms and northwest- and northeast-aligned thrust and strike–slip faults.

Eastern Georgia Basin strata overlie mid-Jurassic to mid-Cretaceous intrusive complexes of the Coast Belt (Monger and Journeay, 1994). Lower Cretaceous Gambier Group volcanogenic sedimentary and volcaniclastic rocks unconformably overlie the intrusive "basement" (Fig. 8) (Lynch, 1991, 1992; Monger and Journeay, 1994). Gambier Group strata consist of massively bedded intermediate to felsic volcaniclastics, local flows and interbedded, fine grained tuff and argillite (Monger, 1991b). Recent palynological studies on well cuttings from the Richfield Sunnyside and Point Roberts wells indicate an Albian to Cenomanian sedimentary succession below the Nanaimo Group (Mustard and Rouse, 1991). These rocks are equivalent in age to Gambier Group rocks exposed farther north (Mustard and Rouse, 1994). In the western Georgia Basin region, the Early Jurassic Bonanza Group of volcanics and its laterally equivalent shale unit (Harbledown Formation), are overlain unconformably by the Upper Cretaceous Nanaimo Group (Fig. 8). In eastern Georgia Basin, the Nanaimo Group unconformably overlies the volcanogenic Gambier succession. The Nanaimo Group consists of up to 4000 m of siliciclastic strata (Mustard, 1991). The succession consists of alternating coarse- and fine-grained sediments and is characterized by an overall upward progression from nonmarine to marine deposits (Mustard, 1991, 1994). Coal beds are common in the lower alluvial/fluvial facies. The largest portion of the succession is represented by deep-marine fan deposits. Fluviodeltaic and turbidite sandstones and conglomerates are potential petroleum reservoirs (England, 1991).

Paleogene strata in the Georgia Basin are represented by the Huntingdon Formation in Canada and the laterally equivalent Chuckanut Formation in Washington State (Vance, 1975; Johnson, 1984; England and Hiscott, 1992) (Fig. 8). The succession consists of nonmarine conglomerates and sandstones, with minor amounts of mudstone and coal. Paleogene strata are up to 2500 m thick and 6000 m thick in Canadian and

American parts of the basin, respectively (Johnson, 1984, 1991; Mustard and Rouse, 1994). In the subsurface, the Huntingdon Formation is interpreted as a thick fluvial sequence with laterally migrating meandering channels in a sand-dominated floodplain (Mustard and Rouse, 1994). There is no evidence of a marine component. In the Vancouver area, Georgia Basin Paleogene and older sedimentary rocks are locally intruded by Oligocene igneous dykes, sills and flows (Hamilton and Dostal, 1994; Mustard and Rouse, 1994).

The Miocene–Pliocene Boundary Bay Formation (Fig. 8) underlies the Fraser Delta area of the Georgia Basin. The Boundary Bay Formation is up to 1200 m thick and consists of interbedded fluvial sandstones and mudstones, and lesser amounts of conglomerate and coal (Mustard and Rouse, 1994). Channel and overbank, floodplain and crevasse splay deposits are recognized (Mustard and Rouse, 1994).

Pleistocene glacial and interglacial sediments blanket the Fraser Delta and Whatcom County areas. In the Bellingham sub-basin, Pleistocene sediments are up to 700 m thick (Hamilton and Ricketts, 1994). The succession consists of glacial tills, stratified fluvioglacial sands and gravels, and peat accumulations (Clague, 1994). The Holocene Fraser River Delta beneath the Strait of Georgia consists of fluviodeltaic sands and muds, in places exceeding 200 m in thickness (Johnston, 1921; Clague et al., 1983; Luternauer et al., 1994).

The principal structures deforming Cretaceous and Paleogene strata in Georgia Basin are northwest-aligned folds and thrust faults. The contractional structures are part of a regional Eocene fold and thrust belt that developed in association with terrane accretion and crustal underplating beneath western Vancouver Island (England and Calon, 1991; England et al., 1997). In parts of the Georgia Basin, strata are also disrupted by Late Eocene and younger northwest-and northeast-trending normal and strike–slip faults (Fig. 26) (Johnson, 1984; Monger and Journeay, 1994; Mustard and Rouse, 1994).

Petroleum geology

Reservoirs

Mesozoic

The oldest sedimentary rocks inferred to have significant reservoir potential in the Georgia Basin are clastics of the Upper Cretaceous Nanaimo Group. These rocks outcrop along the east coast of Vancouver Island on the Gulf Islands in the southern Strait of Georgia. Isolated outcrops occur in the Suquash sub-basin on northern Vancouver Island, the Alberni valley, and in the Lang Bay area directly south of Powell River on the mainland (Figs. 1, 2, 4). Additional isolated outliers of Nanaimo Group are located on Texada Island, Lasqueti Island and on Blue Mountain near Vancouver (Figs. 1, 2, 4). The strata on Blue Mountain were previously considered to be Tertiary (Mustard and Rouse, 1991). Rocks formerly mapped as Tertiary Burrard Formation at the margins and north of Burrard Inlet in the Vancouver area are now considered to be correlative with Nanaimo Group sediments (Mustard and Rouse, 1994). The Nanaimo Group subcrops beneath Tertiary sediments in the Strait of Georgia, western Fraser Valley and Birch Bay area of Washington State (Figs. 3, 26).

The Nanaimo Group has been subdivided into eleven mappable units (not shown on Fig. 8). The formations (in upward stratigraphic order) are: Comox, Haslam, Extension, Pender, Protection, Cedar District, De Courcy, Northumberland, Geoffrey, Spray, and Gabriola. These formations encompass variably alternating sequences of shallow- and deep-marine, marginal-marine and nonmarine clastic deposits. Sandstones, siltstones, shales, conglomerates and coal seams are present throughout the succession, which varies in thickness between 300 and 4000 m. Neritic to bathyal marine depositional environments are represented by outer shelf deep-marine turbidites, submarine fans, and slope facies. Shallow-marine and littoral facies associations represent marginal-marine deposition. Terrestrial deposition includes fluvial–alluvial deltaic and lagoonal deposits. Coal measures are important features of the Extension–Pender–Protection formations.

Sandstones and conglomerates comprise potential reservoir units within the Nanaimo Group. Coarse clastics constitute about 50 per cent of the Nanaimo Group succession, of which five to eight per cent are considered reservoir quality. Six wells penetrate the Nanaimo Group in Georgia Basin. Most coarse clastic beds are tight in these wells. There are, however, minor thin sandstone or conglomerate beds with slight to moderate porosity. An 8% porosity was used as a cutoff for marking reservoir-quality facies. Decomposition of feldspar and volcanic grains within the coarse grained arkosic and lithic sediments resulted in an increased clay content and a subsequent occlusion of pores and reduction in porosity and permeability. Sediments derived from the Coast Plutonic Belt to the east are feldspar-rich. Sands and conglomerates derived from Vancouver Island to the west also produce reservoirs of poor to intermediate quality due to poor sorting and feldspar content. England (1990) made porosity measurements on surface outcrops of the Nanaimo Group on eastern Vancouver Island. His measurements varied from 0 to 11.5% with 8 out of 78 samples exhibiting greater than 8% porosity. Porosities are generally low in Nanaimo Group surface samples (below 5%; Yorath, 1987). Secondary fracture porosity has not been reported with respect to Nanaimo Group rocks. Permeabilities are very low in these rocks in the subsurface (0.01 to 0.06 md). Total reservoir thickness within the 4000 m Cretaceous succession varies from 10 to 200 m, averaging 60 m.

Tertiary

Tertiary rocks underlie the western Fraser Valley, northwestern Washington, and southern Georgia Strait (see Fig. 26). Miocene Boundary Bay clastic rocks unconformably overlie Paleogene Huntingdon/Chuckanut sediments in the Fraser Valley and northwestern Washington State (Fig. 8). These rocks are mainly exposed in scattered outcrops along the lower Fraser River valley and east and northeast of Bellingham in northwestern Washington. Tertiary rocks also outcrop on Tumbo, Sucia, Lummi and Lasqueti islands in the Strait of Georgia. The succession is estimated to be about 2500 m thick in the Fraser Lowland and thickens to 6000 m near Bellingham. The thickness of the prospective succession (interval containing reservoir-quality material), however, seems to be restricted to the upper 2000 m. Sands below 2000 m depth tend to have lower porosities and lack permeability.

Porous sands are generally thin, the majority varying in thickness between 0.6 to 5 m. There are occasional 10-m thick reservoir-quality sands and very rare 30-m porous sands. Potential reservoir sands represent about seven per cent of the total succession. Within individual structures, a succession of stacked reservoirs are present. Gordy (1988) indicated that prospective sands in southwestern British Columbia vary in porosity from 8 to 34%, with an average of 15%. In Washington State, porous sands have an average porosity of 12 to 15%. There is evidence of secondary fracture porosity due to significant water and gas flows below 2000 m depth, where primary matrix porosity is negligible. Significant permeability measurements have been obtained within the Tertiary succession. In the AHEL Birch Bay No. 1 well, permeability is reduced below 1370 m. However, good quality reservoir rock is present above this depth (>100 md/ft.) (Hurst, 1991).

The Paleogene Chuckanut and equivalent Huntingdon formations are nonmarine fluvial and alluvial-type clastic deposits (Johnson, 1984). Medium- to coarse-grained arkosic and lithic sandstones and conglomerates are the principal rock-types with lesser shales, mudstones, siltstones and lignite (Richfield

Oil Corporation, 1962a). Potential reservoir facies include coarse clastic deposits preserved in braided stream channels and alluvial fans. Feldspars and lithic fragments in Paleogene sandstones are less degraded, contain little silica cement and show less compaction compared to Nanaimo Group sediments. Reservoir-quality rocks are more likely to occur in Tertiary sediments than in the Nanaimo Group.

Core analysis of Miocene sediments of southwestern British Columbia reveal that there is a general fining-upward character of quartz and feldspar grains in a cement matrix. Microporosity within the cements (rather than intergranular porosity) characterizes these rocks. The percentage of clay in Miocene sediments generally decreases with depth, resulting in some improvement in reservoir quality in deeper parts of the succession. Porosities vary from 8-21% and permeabilities increase with enlargement of pore size. Reservoir quality is defined as poor to good in Miocene rocks.

Pleistocene

Biogenic gas has been produced from the Pleistocene sands and gravels on the Fraser River delta of British Columbia and the Bellingham sub-basin in northwestern Washington State. Highly porous (15-20% estimate) lenticular gravels and sands within the tills constitute potential reservoir facies within the succession. Gas is likely trapped stratigraphically against impermeable clays. Estimated fraction of reservoir-grade gravels and sands compared to total thickness of Pleistocene deposits is 30 per cent.

Seals

In general, adequate lateral and top seals for Cretaceous and Tertiary reservoir strata are provided by numerous interbedded and overlying shale units in Georgia Basin. Structure-related seals may be present where sandstone and shale units are in fault contact. Seal potential may be reduced for Paleogene strata as a result of an overall high sand content for the units (England, 1991). As mentioned previously, potential gas in unconsolidated gravels and sands in Pleistocene glacial material on the mainland may be trapped laterally and/or vertically by clay-rich boulder clays and tills. However, a greater prospect-level risk for seal was assigned to the Pleistocene interval because of nondeposition of sealing material in some prospective areas.

Traps

Potential petroleum traps found in Upper Cretaceous Nanaimo Group rocks are simple compressional anticlines, faulted anticlines (e.g., Birch Bay; Hurst, 1991), normal faults, drag closures, sandstone pinchouts and unconformity truncations (Table 3). The structural traps were formed during mid- to Late Eocene time. Seismic sections and/or seismic structural contour maps reveal a minimum of approximately 60 identifiable structures or prospects. The largest closure area is 50 km^2.

Traps within the Tertiary succession of Georgia Basin are simple compressional folds, reverse faults, normal faults, sandstone pinchouts and unconformity truncations, singly or in combination (Table 3). An older trend of northwest-aligned compressional folds and minor faults of probable Late Eocene age are cut by a younger set of northeast- to east-trending high-angle normal and reverse faults with apparent dip–slip offsets. These younger structures are interpreted as having formed in mid-Tertiary and older strata (Mustard and Rouse, 1994). The Sumas Mountain and Vedder faults bound a graben structure filled by Quaternary and Recent sediments (Fig. 26). At least 60 structures or prospects in Tertiary strata have been identified from seismic mapping in the area. The identifiable prospects are either four-way closures or traps formed against reverse faults. The largest closure observed covers an area of 50 km^2. Structures occur at various levels in the Tertiary sequence.

Thin, lenticular, sand and gravel body pinchouts against glacial till constitute the stratigraphic trap type in Pleistocene deposits of the Georgia Basin (Table 3). Numerous traps are preserved as a result of the complex stratification of glaciofluvial sands within impermeable boulder clays and tills.

Source rocks

Bustin and England (1991) examined numerous samples of Nanaimo Group material for hydrocarbon potential. Generally, the strata are characterized by low TOC content (< 1%). However, elevated TOC contents do occur in some samples from the Comox, Extension, Pender and Protection formations as a result of the presence of coal seams and coaly material (Fig. 8; Bustin and England, 1991). Humic terrestrial deposits of coal and carbonaceous mudstones represent excellent gas source material. Therefore, coal measures present in these formations have good potential for gas and limited capacity for producing liquid hydrocarbons (England et al., 1989). However, significant gas-generating source material (> 5% TOC), is restricted to the northwestern part of the basin (England, 1991). These rocks have both biogenic and thermogenic gas potential. Bustin and England (1991) also measured Hydrogen and Oxygen indices in Nanaimo Group rocks. Moderate to low average Hydrogen and Oxygen indices indicate that the strata are mainly composed of Type II (oil and gas prone) and Type III (gas prone) organic matter. The low average TOC content and moderate to low Hydrogen Index values indicate poor potential for generation of liquid petroleum and greater potential for gas (Bustin and England, 1991). Liquid hydrocarbons derived from these source rocks are more likely to be condensate rather than oil (England et al., 1989). There may be better source rock potential, possibly oil-generating source material, in the central undrilled area of the basin (Georgia Strait) as a result of euxinic conditions during deposition of marine shales (England, 1991). It is also possible that source rock exists in Triassic basement of Wrangellia. According to England (1991), gas and condensate seeps are present on the western margin of Georgia Basin.

Source rocks have been identified in the Tertiary sedimentary succession. Coal seams within Eocene sediments in northwest Washington and organic-rich shales found throughout the basin are important source material for light hydrocarbons (gas and condensate). Good oil source rocks have not been identified as yet in Tertiary Georgia Basin. Even though abundant liquid-hydrocarbon-prone Type IIB kerogens have been distinguished in Eocene Chuckanut rocks, oil generation has probably been retarded by low maturity resulting from the shallow burial of Eocene strata. The Eocene Chuckanut rocks also have TOC contents up to 6% (Hurst, 1991). In Birch Bay No. 1 well (Fig. 3; Table 2), high concentrations of Type IIB kerogens are present with numerous intervals of elevated TOC content (Hurst, 1991). Rocks below 1830 m depth in the Birch Bay well contain humic Type III kerogen (gas prone) with a low TOC content. Organic shales and coal seams in Miocene sediments retain Type III kerogens with TOC varying from 1 to 17%. Gas seeps have been reported throughout the lower Fraser valley and in northwestern Washington (Johnston, 1923; McFarland, 1983; Hurst, 1991; Lingley and von der Dick, 1991).

It has been determined that reported oil shows, especially within eastern Georgia Basin, represent industrial contaminants rather than natural occurrences (Johnston, 1923; Moen, 1969; McFarland, 1983). Geochemical data indicate the area is not likely oil-prone (Gordy, 1988; England, 1991; Bustin and England, 1991; Yorath, 1987).

In summary, Georgia Basin contains good gas-source rocks in both Cretaceous and Tertiary sections, but no mature oil-source rocks have yet been identified. Thus, Georgia Basin is currently considered to be exclusively a gas/condensate hydrocarbon province.

Source rock maturation

Generally, the Nanaimo Group sediment succession is mature with respect to hydrocarbon generation (England, 1990). Nanaimo Group rocks are overmature (Ro as high as 4.6%) adjacent to Tertiary plutons or in areas of overthrusting (England, 1991; Mustard, 1994). In subthrust positions in the Cowichan Fold and Thrust Belt, vitrinite reflectance values are well into the gas window (Ro > 1.3%) (England, 1991). A depth/maturity plot for the Yellow Point well drilled entirely in Nanaimo Group strata (Fig. 27; see Fig. 3 and Table 2 for well location) reveals all the succession is in the gas generation zone (0.7 to 1.3% Ro). These sediments also occupy the oil window from surface to total depth, but lack of a suitable source rock for oil precludes oil generation. Bustin and England (1991) reported vitrinite reflectance values of Nanaimo Group rocks varying from 0.4 to 5% Ro (immature to overmature) from their sampling program on Vancouver Island. The sampling revealed that throughout the Georgia Basin proper, most of the strata have maturation levels within the oil window while in the Suquash sub-basin, the rocks are mainly immature. According to the predicted model, the Cretaceous Nanaimo and Gambier-equivalent sedimentary succession at Point Roberts is mature with respect to hydrocarbon generation where it is buried under 3000 m of Tertiary and Quaternary rocks (Fig. 28, see Fig. 3 and Table 2 for well location). Maturation levels offshore in Georgia Strait are unknown, but they are expected to vary from mature to overmature. Possible oil generation may occur in the more deeply buried marine shales found in the Nanaimo Group in Georgia Strait.

According to numerous studies of the Tertiary succession of Georgia Basin, levels of organic maturation range from immature to marginally mature, regardless of depth (Bustin, 1990; England, 1991; Hurst, 1991; Lingley and von der Dick, 1991; Mustard and Rouse, 1991). Vitrinite reflectance measurements from the Point Roberts well, for example, vary from 0.4 to 0.6% Ro from surface to 4400-m total depth. There is effectively no increase of reflectance with depth of burial (Bustin, 1990; Fig. 28). The ambiguity of this data prevents rigorous interpretation. The only conclusion is that Tertiary strata are immature to marginally mature with respect to hydrocarbon generation. Thermal alteration indices obtained from the Richfield Sunnyside well near by indicate marginally mature strata (Mustard and Rouse, 1991). Surface and subsurface samples from the Point Roberts area also reveal the TAI is in the marginal mature range. England (1991) demonstrated that surface samples of Paleogene strata at southeastern Vancouver Island and Gulf Islands are mainly immature to early mature (0.29 to 0.66% Ro). Thus, all available maturation data indicate Tertiary strata in Georgia Basin are probably too immature for the generation of large volumes of thermogenic gas. In several wells in the Bellingham sub-basin in Washington State, pyrolysis and vitrinite reflectance data indicate Tertiary strata are marginally mature, with little apparent increase in maturation levels to depths of up to 2000 m (Hurst, 1991; Lingley and von der Dick, 1991).

Timing of hydrocarbon generation

Major compressional structures formed during mid to late Eocene time. Most of the basin fill was deposited during Upper Cretaceous to lower Eocene. England (1991) suggested the timing of hydrocarbon generation with respect to structure formation due to compressional deformation poses a potential risk for the trapping of hydrocarbons in Georgia Basin. England's basin model suggests that the initial gas charge produced by normal burial metamorphism with prevailing low geothermal gradients predates trap formation. However, trap formation is inferred to postdate hydrocarbon generation in other hydrocarbon-bearing settings such as the Foothills of the Canadian Cordillera. This study considers that this timing problem does not significantly detract from the potential in the Georgia Basin, although it does increase the play risk. Secondary hydrocarbon generation can be achieved by continuous burial of Cretaceous and Paleogene strata by thick

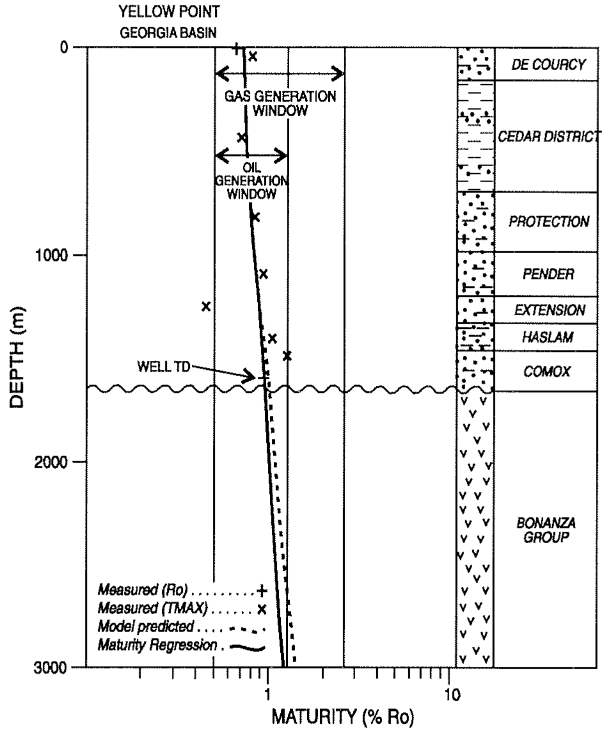

Figure 27. Maturation–depth profile of strata in the Yellow Point d-84-C location, Georgia Basin (see Fig. 3 and Table 2 for well location). Single surface vitrinite reflectance value obtained from England and Calon (1991). Measured subsurface TMAX values are from Bustin and England (1991). Model-predicted maturation profile based on illustrated stratigraphy and heat-flow model where heat flow is reduced from 40 mW/m^2 to 35 mW/m^2 at 50 Ma. Subduction of oceanic crust commencing in mid-Eocene beneath Vancouver Island produces a large overlying wedge of cool crust (Lewis et al., 1992). Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995).

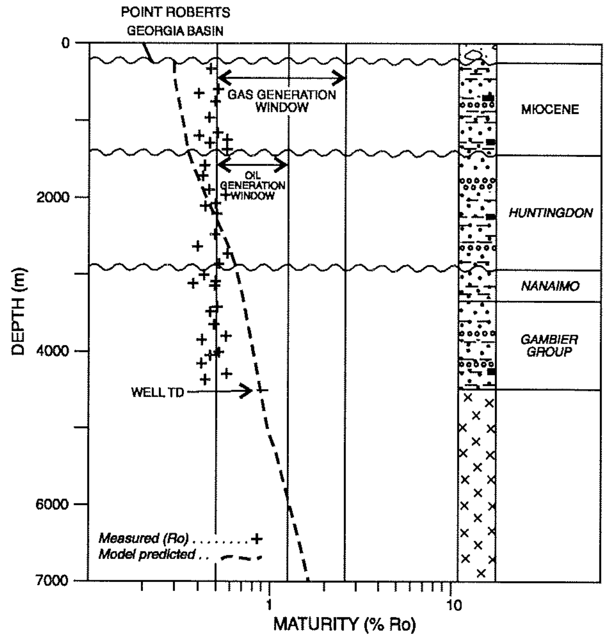

Figure 28. Maturation–depth profile of strata in the Richfield Pure Point Roberts 6-3-5 location, Georgia Basin (see Fig. 3 and Table 2 for well location). Measured subsurface vitrinite reflectance values obtained from Bustin (1990). Model-predicted maturation profile based on illustrated stratigraphy and constant heat flow of 35 mW/m^2 (heat flow derived from Lewis et al., 1992). Note ambiguous results for measured vitrinite reflectance. No apparent increase in vitrinite reflectance as a function of depth, expected with normal burial metamorphism, occurs in the subsurface. The only conclusion possible is that all strata are immature to mature with respect to hydrocarbon generation. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995).

accumulations of Neogene material in eastern Georgia Basin and by tectonic burial in subthrust positions in the Cowichan Fold and Thrust Belt (England, 1991; Mustard, 1994). Traps resulting from extensional deformation, such as normal fault traps, postdate the major hydrocarbon charge brought on by normal burial metamorphism. Deep-seated faults may provide pathways for hydrocarbon migration upsection or updip into potential traps.

In eastern Georgia Basin, modelled burial history curves indicate hydrocarbon generation occurring in the interval from late Miocene to Recent time in Gambier-'equivalent' sediments. This postdates mid-Eocene folding and faulting (Point Roberts well; Fig. 29). This model suggests that hydrocarbons will encounter numerous compressional and extensional traps. Timing is not inferred to be a problem in this area. This model assumed a constant heat flow throughout the burial history (35 mW/m^2). Published heat flow data for the southern Canadian Cordillera gives an average of 35 mW/m^2 for the Georgia Basin region (Lewis et al., 1992).

Modelling of the Nanaimo Group sedimentary succession at the Yellow Point well on southeastern Vancouver Island reveals that hydrocarbon generation commences in latest Cretaceous time and continues to Recent (Fig. 30). The mid-Eocene deformation episode provides opportunities for trapping generated hydrocarbons. Timing of trap formation with respect to hydrocarbon generation is not inferred to be a significant problem in this part of the Georgia Basin. This model assumes a reduction in heat flow at 50 Ma (mid-Eocene) (40 mW/m^2 to 35 mW/m^2) reflecting the commencement of subduction of oceanic crust beneath Wrangellia, which in turn cools the overlying crustal wedge.

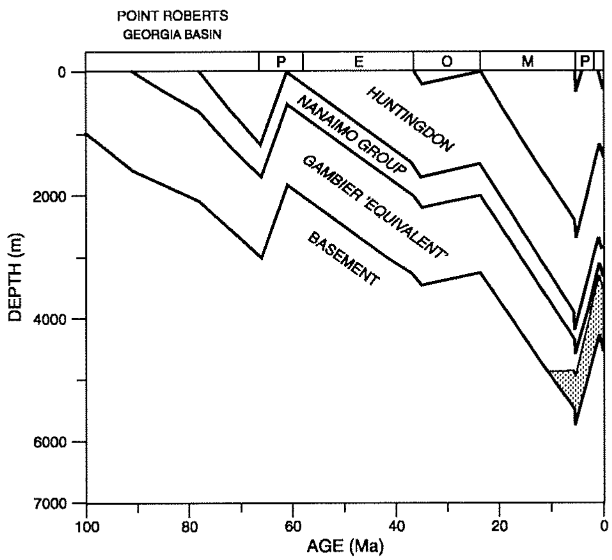

Figure 29. Subsidence and hydrocarbon generation model for the Point Roberts area, Tertiary Georgia Basin. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995). Hydrocarbon generation models based on standard (BasinMod) kinetic parameters for organic matter types (Types II–III in Boundary Bay and Huntingdon strata and Type III in Nanaimo and Gambier-equivalent strata). See text for discussion.

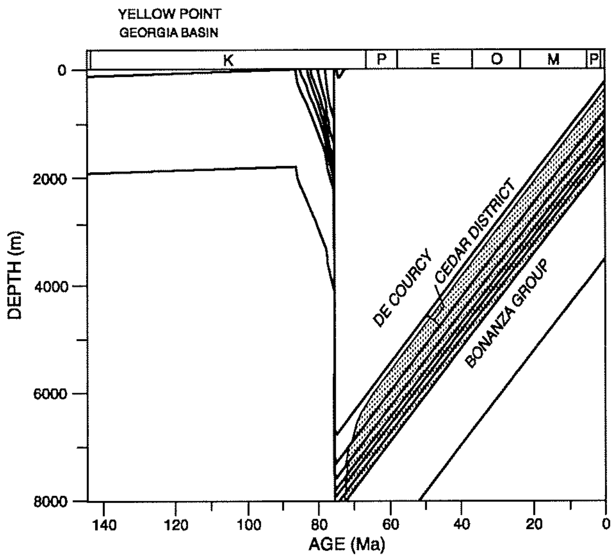

Figure 30. Subsidence and hydrocarbon generation model for Yellow Point area, Cretaceous Georgia Basin. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995). Hydrocarbon generation models based on standard (BasinMod) kinetic parameters for organic matter types (Types II–III in Protection, Pender, Extension and Comox strata and Type III in De Courcy, Cedar District and Haslam strata). See text for discussion.

Hydrocarbon shows

Numerous gas shows and limited gas production have been described in driller's logs, well history reports, geological reports and published papers (Key Oil & Gas (1955), Ltd., 1958; Pacific Petroleum Ltd., 1959; Moen, 1969; British Petroleum, 1987a; Gordy, 1988; Hurst, 1991). Gas production from glacial sands and gravels at shallow depths has been reported in the Bellingham sub-basin. Six wells near Birch Bay are all former domestic gas producers (Fig. 3). Production rates and pressures were reported for five of these wells (21,237 to 141,585 m^3 per day at 186 to 482 Kpa) (Glover, 1935; Moen, 1969). Gas analyses indicate major constituents are methane and nitrogen suggesting a dry biogenic gas source, probably coal seams (Moen, 1969). The gas derived from underlying coal seams migrated upward and accumulated in the porous glacial sands and gravels in stratigraphic traps. Gas shows have also been reported from Pleistocene sediments encountered in eight wells in Bellingham sub-basin.

Numerous gas shows have been reported from Tertiary strata in Bellingham sub-basin. More than 98 hydrocarbon shows were encountered in 84 wells that penetrated the Tertiary succession. Many old drilling reports refer to "several" or " a few" hydrocarbon shows. Miocene Boundary Bay sediments have more than 20 hydrocarbon shows of which 17 were coalbed methane 'kicks' encountered in one well. Seventy-eight shows occur in Eocene/Lower Oligocene Huntingdon/Chuckanut formations. Most shows are gas, but minor oil occurrences have been reported. It has been suggested, however, that these oil occurrences are probably contaminants or refined oil spills rather than naturally occurring accumulations (Moen, 1969; Gordy, 1988).

In the Cretaceous interval, six gas shows from six wells have been reported; most are methane gas kicks from coal seams. Hurst (1991) reported that American Hunter's well at Birch Bay encountered gas shows below 6000 feet (1830 m) depth in Cretaceous rocks. Analysis of gas seeps from old well casings revealed a thermogenic origin with some biogenic mixing (Hurst, 1991). The presence of numerous thermogenic gas shows both in Cretaceous and Tertiary sediments indicates potential for commercial quantities of gas in Georgia Basin.

Petroleum assessment

Two conceptual and one immature play are recognized in Georgia Basin. Assessment computations were performed for natural gas only in the Georgia area of the West Coast. Oil assessments were not undertaken for these plays because geochemical data suggest the area is not likely oil-prone.

Petroleum plays

Georgia Cretaceous structural gas play

Play definition. The Georgia Cretaceous gas play includes structural and structural–stratigraphic traps in Cretaceous strata in Georgia Basin (Figs. 2, 3, 31). The play area includes the western Fraser delta, Strait of Georgia, southern Gulf Islands and eastern coast of Vancouver Island.

Geology. Prospects involve single or stacked Cretaceous sandstones in anticlines or thrust fault blocks. Stratigraphic trap components include pinchouts and unconformity truncations.

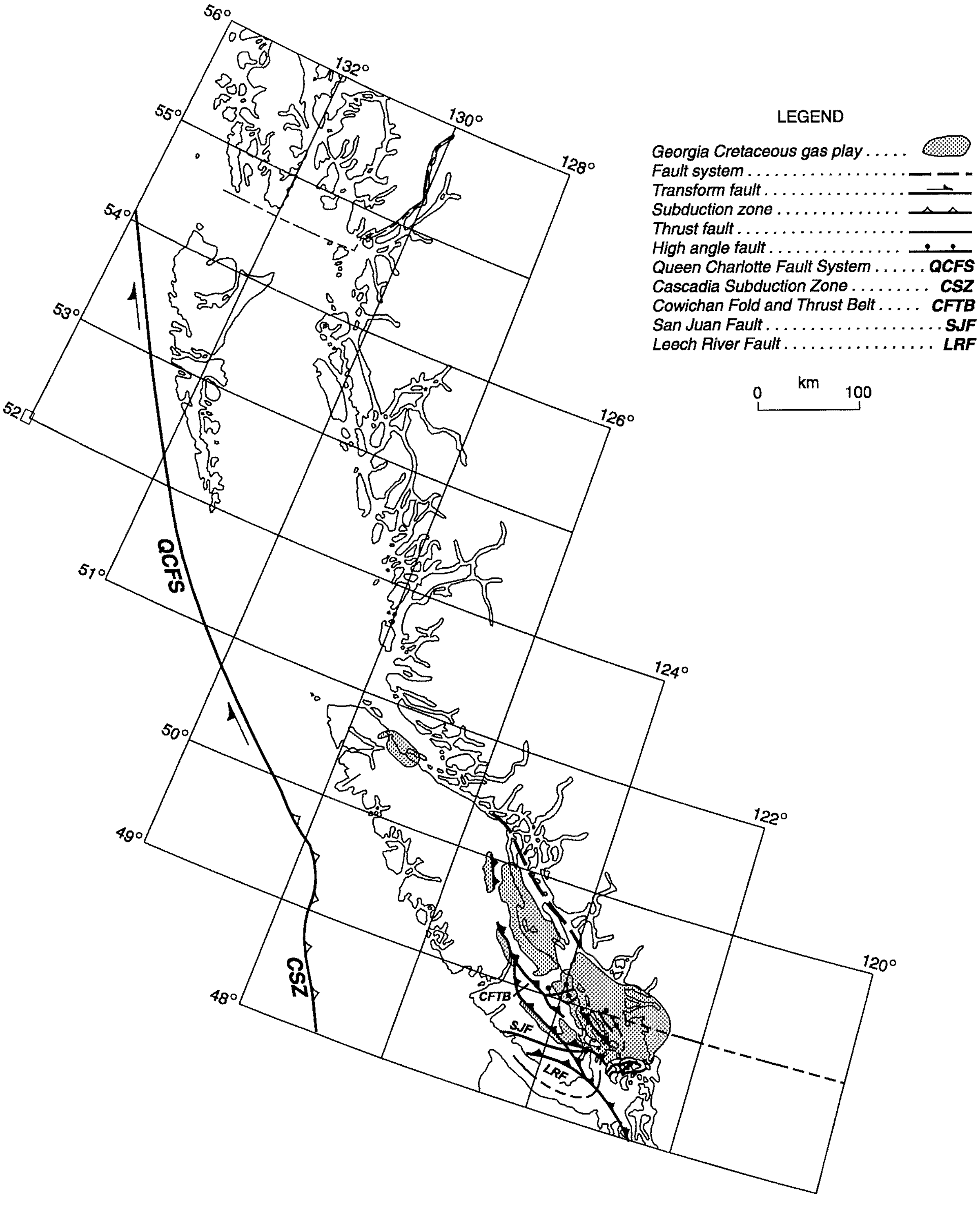

Figure 31. Georgia Cretaceous structural gas play area. Major structural elements are illustrated.

Exploration risks. The exploration risk for the conceptual Georgia Cretaceous play is estimated at 0.10, with most of the risk associated with adequacy of reservoir facies. Pacht (1984) identified lithic arkoses and volcanic lithic arenites as the predominant sands on eastern Vancouver Island. Porosity in these rocks is probably low because diagenetic activity causes breakdown of abundant feldspars and volcanic clasts into clay minerals that often plug pores in sandstones. Although structure, source rock, and maturity characteristics are favourable for hydrocarbon formation and accumulation, the lack of porosity development will establish a higher risk for exploration success in the play (Appendix I, Table I.7b).

Play potential. The total median play potential is 118.5 billion m^3 of gas (Fig. 32, Table 4). The estimated median of the largest field size is 32 billion m^3. The number of fields expected in the play is 45. Compared to the other plays in the Georgia Basin, this play possesses the greatest potential. However, the Cretaceous play carries a higher exploration risk for adequate conditions for hydrocarbon accumulation.

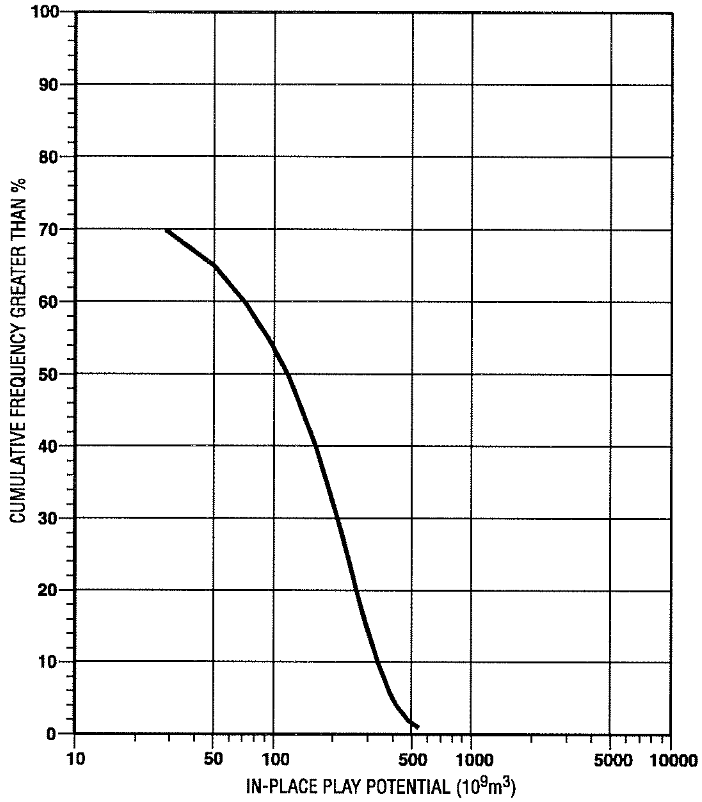

Figure 32. **Estimate of in-place gas potential of the Cretaceous structural play in Georgia Basin. Median value of probabilistic assessment is 118.5 billion m^3 of in-place gas distributed in 45 fields.**

Georgia Tertiary structural gas play

Play definition. The Georgia Tertiary gas play includes structural and structural–stratigraphic traps in Tertiary strata in Georgia Basin. The play area encompasses the onshore Lower Mainland in the Vancouver area and offshore Strait of Georgia (Figs. 3, 33).

Geology. Prospects include Tertiary sandstones (commonly in stacked successions) in anticlines, thrust and normal fault traps, and stratigraphic pinchouts and unconformity truncations.

Exploration risks. The Georgia Tertiary play was assigned an exploration risk of 0.56, with most of the risk associated with the presence of closure and the adequacy of seal (Appendix I, Table I.8b).

Play potential. The estimated median resource potential for the play is 59 billion m^3 of gas in 93 fields (Fig. 34, Table 4). The median estimate of the largest field size is 9.8 billion m^3 of gas.

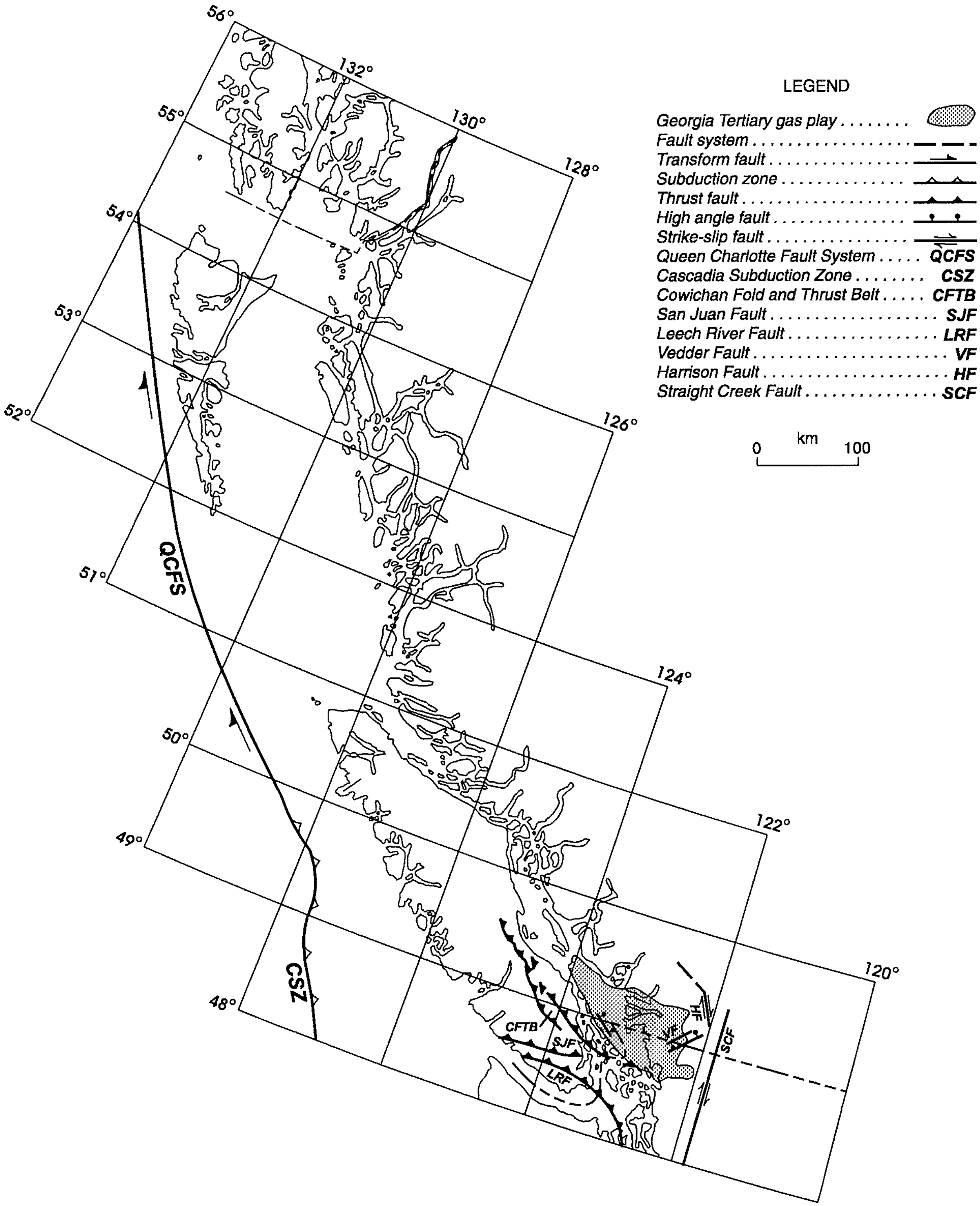

Figure 33. Georgia Tertiary structural gas play area. Major structural elements are illustrated.

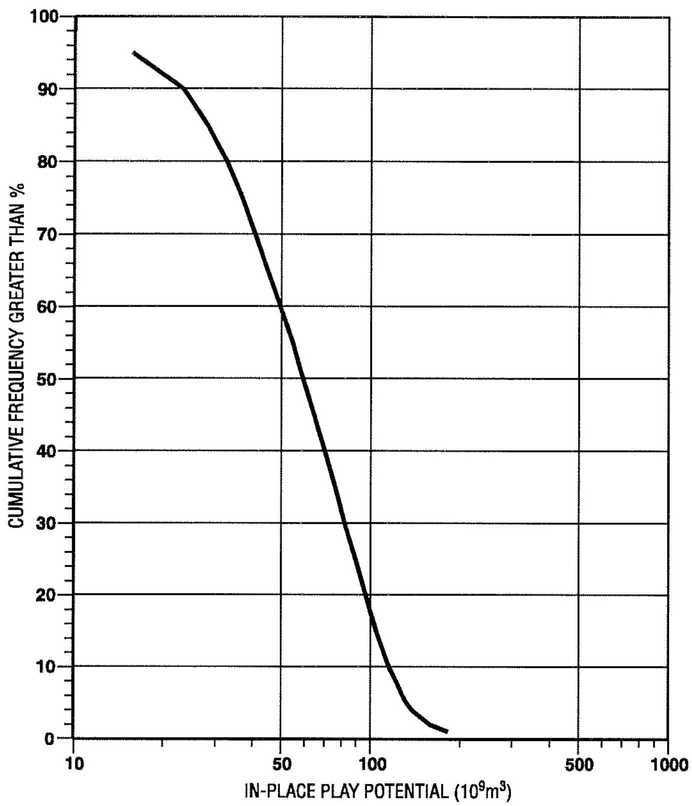

Figure 34. Estimate of in-place gas potential of the Tertiary structural play in Georgia Basin. Median value of probabilistic assessment is 59 billion m^3 of in-place gas distributed in 93 fields.

Georgia Pleistocene stratigraphic gas play

Play definition. The Georgia Pleistocene stratigraphic play encompasses all stratigraphically trapped gas within Quaternary unconsolidated sediments in Bellingham sub-basin. The play area encompasses the Fraser delta and Fraser lowlands (Figs. 2, 3, 35).

Geology. The play consists of stratigraphic traps involving lenticular sands and gravels encased in impermeable mudstone. These traps reflect the complex stratification of glaciofluvial sands within impermeable boulder clays and tills. Coal seams found in underlying Tertiary sediments are potential sources for the dry, biogenically generated gas for the play.

Exploration risks. The exploration risk for the Georgia Pleistocene play was estimated at 0.40, with most of the risk associated with the adequacy of seal (reflecting the shallow burial of reservoir units and erratic distribution of mudstones and clays) (Appendix I, Table I.9b).

Play potential. The median potential gas resource of the play is 207 million m^3 of gas in 92 expected fields (mean value) (Fig. 36, Table 4). The largest field in the play is predicted (at median value) to contain 10.4 million m^3 of in-place gas.

Discussion of assessment results

Resource potential. Total gas potential for all three plays in Georgia Basin is 185 billion m^3 (6.5 Tcf) (in-place volume) distributed in 230 predicted fields (Table 4; Fig. 37). The high confidence (90% probability) and speculative (10% probability) estimates of total gas potential in Georgia Basin are 43.3 and 419.9 billion m^3 (1.5 and 15 Tcf), respectively. Total estimated gas resource for the Georgia Basin constitutes about one quarter of the predicted potential for the Queen Charlotte Basin area. Although the Georgia Basin assessment region is predicted to contain a larger number of gas fields than the Queen Charlotte Basin assessment region (Table 4), the sizes of the fields are predicted to be smaller in the former area.

Resource distributions. The greatest gas potential occurs in the Cretaceous structural play, principally because of its larger play area. The largest individual gas field is predicted to occur in the Cretaceous play as well, with a median size estimate of 32 billion m^3 (1.1 Tcf). Field-size rankings of all plays suggest about

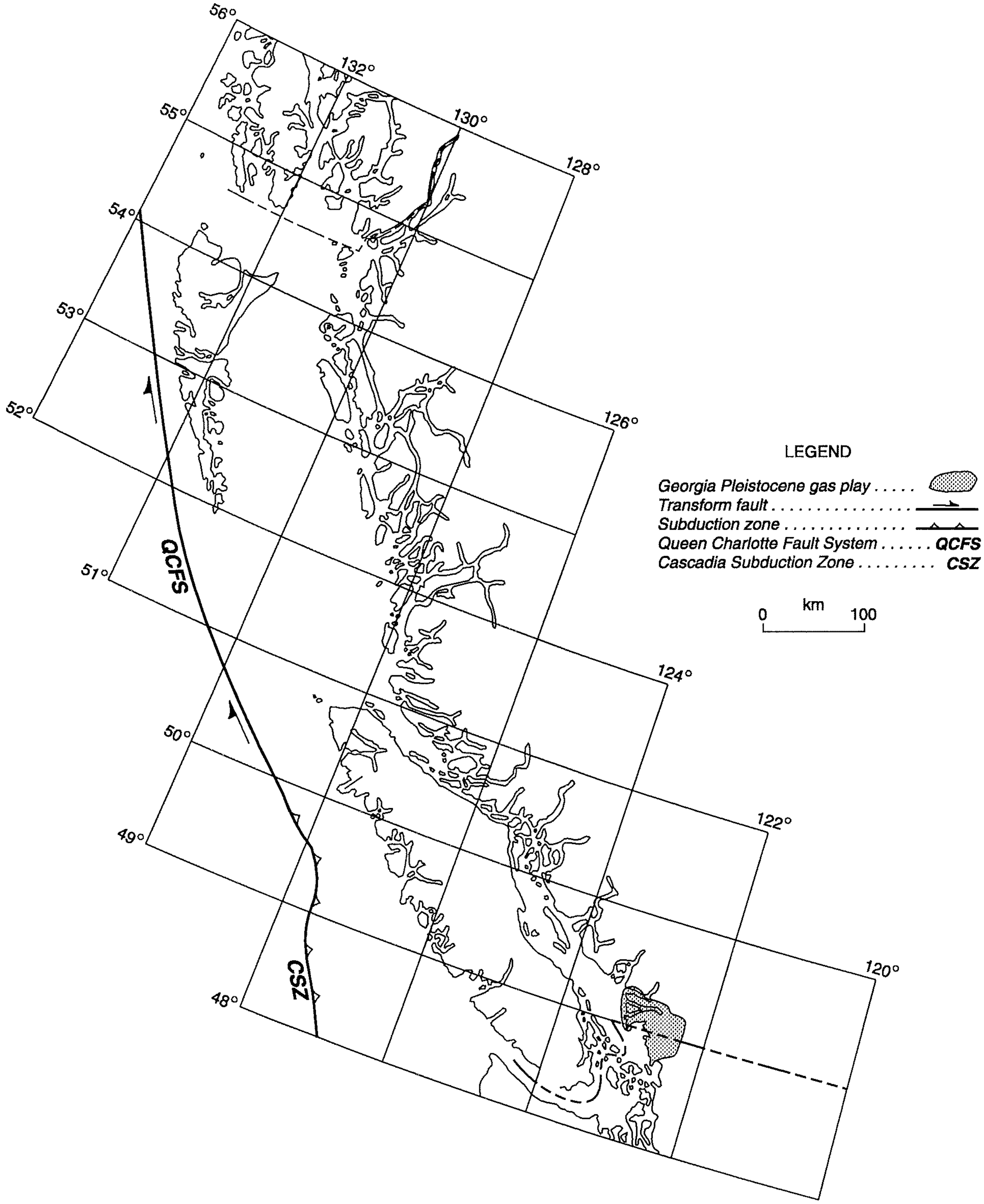

Figure 35. Georgia Pleistocene stratigraphic gas play area. Major structural elements are illustrated.

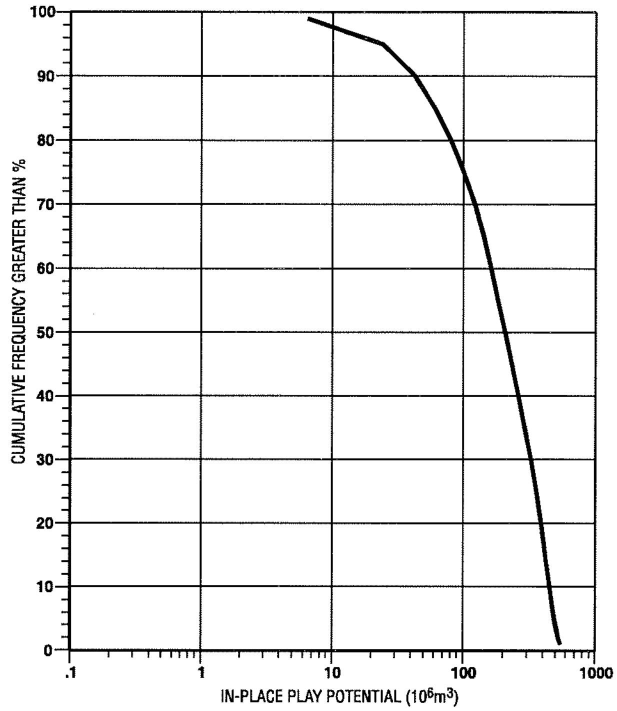

Figure 36. **Estimate of in-place gas potential of the Pleistocene stratigraphic play in Georgia Basin. Median value of probabilistic assessment is 207 million m^3 of in-place gas distributed in 92 fields.**

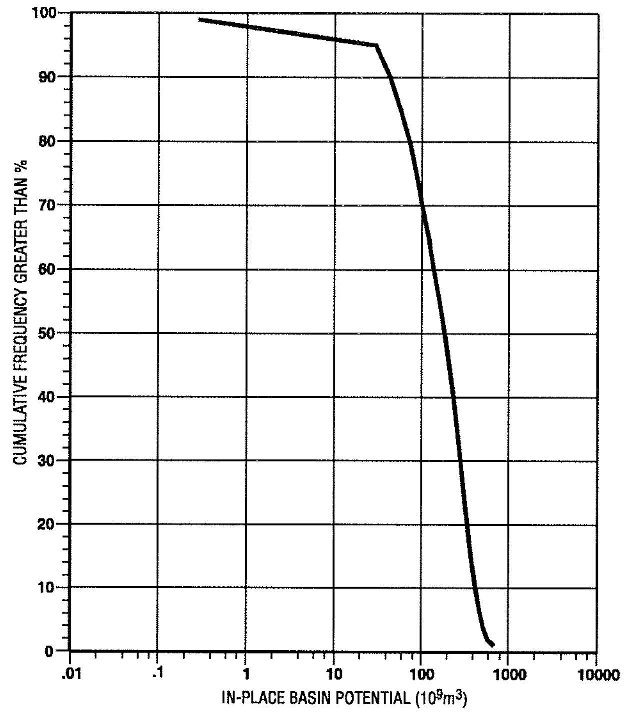

Figure 37. **Estimate of total gas potential for the Georgia Basin region. Median value of probabilistic assessment is 185 billion m^3 of in-place gas.**

40 per cent of the basin's total petroleum resource is contained in the five largest expected gas fields. This is comparable to average distributions of hydrocarbons in most basins worldwide (Klemme, 1984).

For Georgia Basin, as a whole, the Cretaceous play contains about 70 per cent of the region's expected total gas volume and 8 of the 10 largest fields. Geographically, the most prospective area in Georgia Basin is the Bellingham sub-basin onshore including the Fraser River valley and delta in British Columbia and Whatcom County in Washington (Figs. 2, 3). The optimum combination of reservoir-quality sands, large traps, and abundant source material is present in the area. Less prospective areas in the Basin, in descending order are: the Strait of Georgia, the Nanaimo sub-basin of eastern Vancouver Island and Gulf Islands, the Suquash sub-basin, and the Comox sub-basin. Very little petroleum potential is expected on eastern Vancouver Island because of the paucity of reservoir-quality sandstones and source rock, particularly in the Comox sub-basin.

Assessment results and exploration history. Average exploration risks estimated in the assessment for the Georgia Basin region (for all three plays) suggest success rates for exploration drilling in the region should average about one in three, that is, the probability of finding accumulations of gas in Georgia Basin in all three plays is approximately 0.33. The lower success rate of historical drilling (that is, 15 former domestic gas-producing wells out of 122 wells drilled) may indicate a higher exploration risk than estimated here. However, a vast majority of these boreholes were originally drilled as water wells and are probably inadequate or only partly diagnostic petroleum tests. Many of the wells (81) were drilled before 1960 and presumably no geophysical surveys or mechanical well logs were used for locating many of the potential drill-sites. Stratigraphy and structure deduced from limited outcrop exposure and lithological descriptions from earlier drilling provided the basis for petroleum exploration previous to 1960. The majority of seismic reflection survey work acquired in the 1960s characteristically exhibits poor to fair data quality compared to current techniques. No doubt many wells placed by these surveys were drilled in less than optimum locations. Only five wells have been completed since 1980, following development and refinement of modern seismic survey techniques.

Distribution of resources in Canada. Hydrocarbon plays in the Georgia region occupy areas on both sides of the International Border. If it can be assumed that the hydrocarbon resources are evenly distributed throughout the play area, the proportion of resource residing in Canada can be estimated by comparing play areas between the two countries. Although the location of the largest field cannot be determined, there is no reason that all or part of the largest predicted field is not present in Canada. About two thirds of the Georgia Pleistocene stratigraphic play area is located in Canada, so the amount of estimated gas resource potential is 138 million m^3 (median value) in Canada. Similarly, two thirds of the play area of the Georgia Tertiary structural play is found in Canada, so the median gas potential for Canada is 39.5 billion m^3. In the Georgia Cretaceous structural play, 85 per cent of the play area is located in Canada. Assuming even distribution of the gas resource, the proportion of gas potential present in Canada is 101 million m^3 (median value).

TOFINO ASSESSMENT REGION

Exploration history and regional studies

Aeromagnetic and reflection and refraction seismic surveys were conducted in the 1960s by Shell Canada in the Tofino Basin. The aeromagnetic survey delineates long and linear total intensity magnetic anomalies parallel to the west coast of Vancouver Island (Shouldice, 1971).

Numerous academic and government seismic surveys and studies were also performed in the area. Continuous seismic profiles combined with bathymetry illustrate basin topography and geometry of the western Canadian continental margin (Chase et al., 1975). Side-scan sonar, 3.5 kHz profiles and submersible traverses carried out by the Geological Survey of Canada (GSC) and multichannel seismic lines acquired by Shell were used to delineate and investigate the Apollo structure in the Tofino Basin (see Fig. 38 for schematic geological section through the Apollo structure partly derived from seismic data) (Yorath, 1980). Numerous seismic reflection profiles acquired by Chevron, the University of British Columbia and the Geological Survey of Canada were employed to provide a unified interpretation of the tectonics and structure of the Winona Basin (Davis and Riddihough, 1982). Four, multichannel, deep crustal seismic lines were recorded onshore Vancouver Island as part of the LITHOPROBE programme. These lines depict the deep crustal structure and geometry of the subduction zone beneath the Island (Green et al., 1985; Yorath et al., 1985a, 1985b; Sutherland Brown and Yorath, 1985; Green et al., 1986; and Clowes et al., 1987). Multichannel seismic reflection lines in Tofino Basin collected in 1985 by the GSC along with acoustic imagery and bathymetry data were used to illustrate the surface morphology, internal geometry and deformation style of the accretionary prism (Figs. 4, 39) (Davis and Hyndman, 1989; Davis et al., 1990; and Hyndman et al., 1990). A 1988 deep seismic reflection survey of the Queen Charlotte Basin region included one line that crossed the Winona Basin (Figs. 4, 40) (Rohr and Dietrich, 1990, 1991). This line illustrates the wedge-shaped sediment package overlying oceanic crust. Another marine multichannel seismic survey (722 kms) acquired by the GSC in 1989 in Tofino Basin clarifies the regional structure and stratigraphy, examines the physical properties related to the bottom-simulating reflector interpreted as a methane hydrate layer, and studies the nature of the detachment that could produce large earthquakes (Spence et al., 1985; Singh et al., 1990). Dehler and Clowes (1992) and Clowes et al. (1987) used integrated geophysical studies to develop structural models across the continental margin west of Vancouver Island. Gravity and magnetic

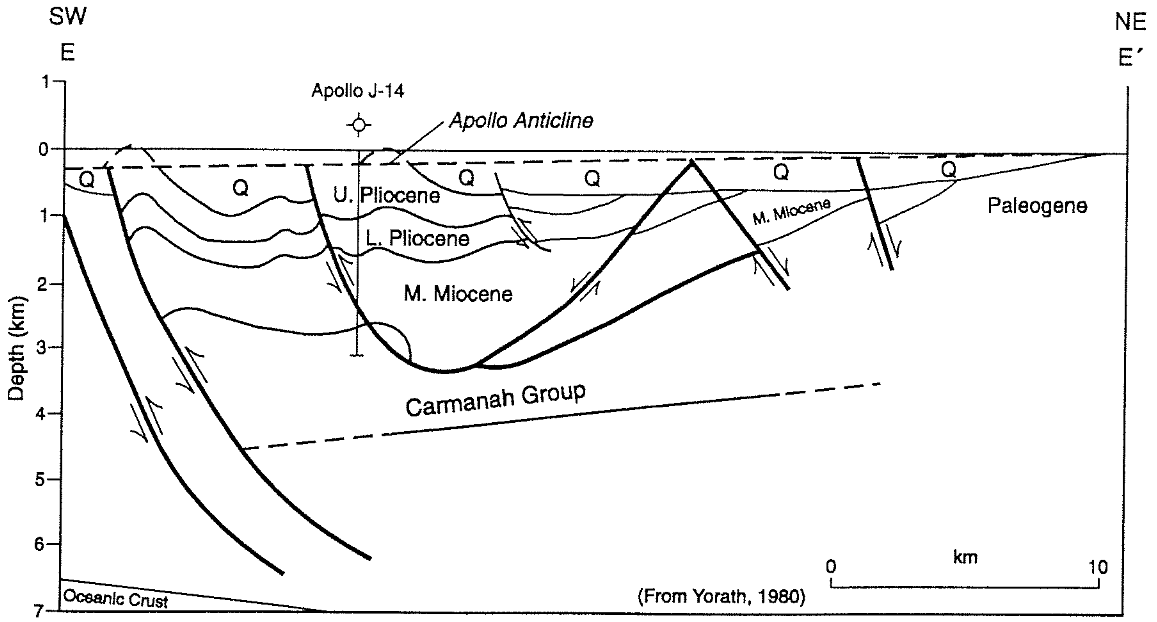

Figure 38. Geological cross-section (derived from seismic and well data) in Tofino Basin (EE'; location in Fig. 2) (modified from Yorath, 1980). Main faults are interpreted from seismic sections.

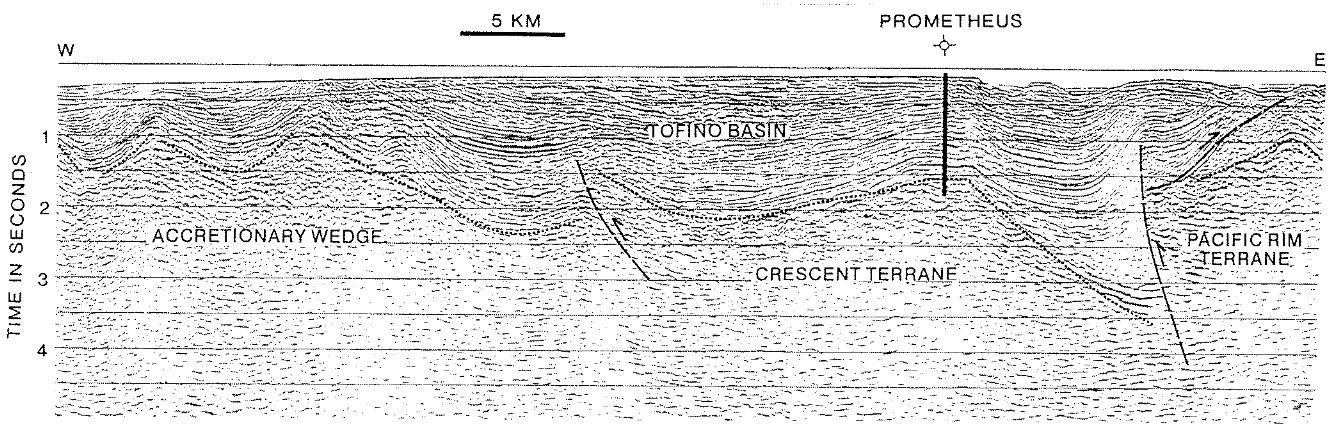

Figure 39. Seismic reflection profile, Pacific Ocean offshore, southern Vancouver Island (data from Spence et al., 1985; interpretation modified from Hyndman et al., 1990). The upper Tertiary–Quaternary Tofino Basin overlies deformed (accretionary wedge) Tertiary sedimentary strata and Mesozoic volcanic and metasedimentary rocks of the Pacific Rim and Crescent terranes. Structural features include compressional folds and thrust faults. The Prometheus well encountered gas shows in shallow Pleistocene sandstones.

data, as well as seismic profiles, were interpreted to constrain the offshore positions of various accretionary terranes.

Shell Canada Ltd. drilled six offshore wells on seismically defined structures in the late 1960s in Tofino Basin (Fig. 2, Table 1) (Shell Canada Ltd., 1968 f, g, h, i, 1969 d, e). Four onshore wells were also drilled on the northern coast of Olympic Peninsula in the Juan de Fuca Basin (Fig. 2, Table 1) (Niem and Snavely, 1991).

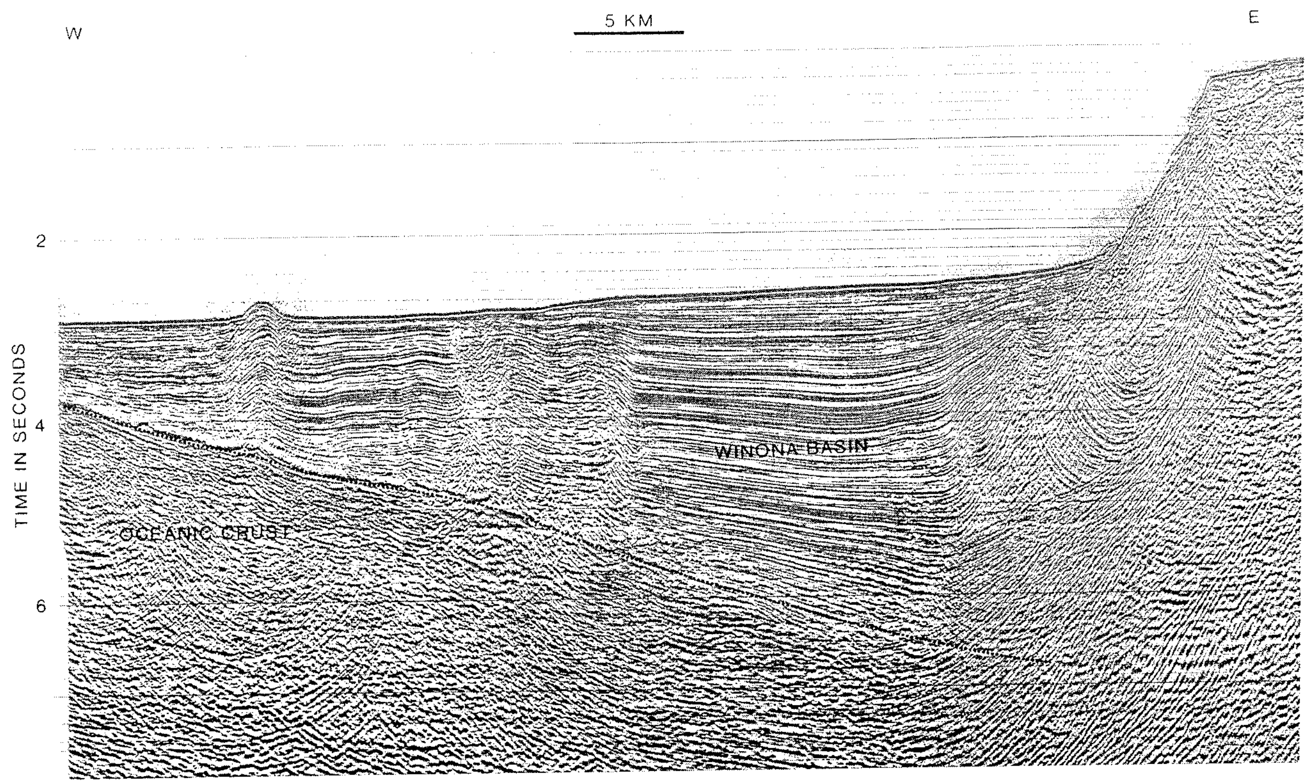

Figure 40. Seismic reflection profile, Pacific Ocean offshore, northern Vancouver Island (data from Rohr and Dietrich, 1990). The wedge-shaped Winona Basin at base of the continental slope (1500–2200 m water depths) contains up to 8 km of Plio-Pleistocene sedimentary strata, overlying oceanic crust. Interbasin structural features include compressional folds and thrust faults.

Regional geology

Geological setting and tectonic evolution

The Tofino Basin and adjacent accretionary wedge are upper Tertiary forearc and accretionary basins that developed in response to convergence and orthogonal subduction of the Juan de Fuca Plate beneath the continental margin. It is speculated that Winona Basin is a Plio-Pleistocene deep-water basin that developed by flexural bending in response to oblique convergence or transpression of the Explorer oceanic plate against the North American plate (Davis and Riddihough, 1982; Yorath and Hyndman, 1983) .

The Tofino Basin underlies some 15,000 square kilometres of the continental shelf offshore Vancouver Island. The Juan de Fuca sub-basin represents a southern extension of the basin beneath Juan de Fuca Strait and adjacent coastal areas of Vancouver Island and Olympic Peninsula (Fig. 2).

The deep-water Winona Basin and accretionary wedge encompass a total area of about 25,000 square kilometres seaward of the continental shelf edge. The Winona Basin is a Plio-Pleistocene basin at the foot of the continental slope. The accretionary wedge is a deformed Tertiary sedimentary prism overlying oceanic crust of the Juan de Fuca plate. Along the outer continental shelf, the accretionary wedge is underthrust beneath the Tofino Basin (Hyndman et al., 1990).

Stratigraphy and structure

The Tofino Basin contains up to 6000 m of upper Paleogene–Neogene sedimentary strata. The basin-fill includes deep-marine mudstones and sandstones and minor conglomerates of the upper Paleogene Carmanah Formation and an overlying unnamed Neogene succession of marine sandstones, siltstones, and mudstones (Fig. 8). In the eastern Tofino Basin, "basement" for petroleum exploration consists of Cretaceous metasedimentary rocks of the Pacific Rim Terrane and Eocene volcanic rocks of the Crescent Terrane (Fig. 39). In outer shelf areas where the basin overlies Paleogene accretionary wedge sediments, there is no sharply defined "basement". The accretionary wedge, seaward of the shelf edge, consists of up to 6000 m of Tertiary strata. The Winona Basin contains up to 8000 m of Pleistocene strata. Deposits in both areas consist exclusively of deep-marine mudstones and turbidite sandstones. On the northern shore of Olympic Peninsula, 6000 m of Middle Eocene to early Miocene sediment unconformably overlies the Lower Eocene Crescent Formation. These sediments consist of lithic turbidite sandstones, deep-marine mudstones and minor polymict conglomerates and sedimentary breccias (Niem and Snavely, 1991).

The most abundant structures in Tofino Basin are northwest-aligned curvilinear folds. One such fold, the Apollo anticline, occurs above an intra-Neogene detachment (Fig. 38). The folds developed in response to Plio-Pleistocene subduction of the Juan de Fuca Plate and accretionary wedge beneath the basin. In eastern and southern Tofino Basin, Tertiary strata are variably disrupted by Neogene thrust, strike–slip and normal faults that developed in association with terrane underplating. Seismic surveys recorded by Shell Canada in the 1960s manifest the structural style in the deep-water offshore area. Generally, structures are large and dips are moderate so deformation is not extreme. Some of the structures involve volcanic "basement"; others do not. Some of the compressional folds are faulted and some indicate an extremely complex structural history with small, episodic periods of growth over a long period of time.

Petroleum geology

Reservoirs

Tertiary

Deep-marine outer shelf to bathyal mudstones and siltstones dominate the Tertiary sedimentary succession within the Tofino Basin (Fig. 8). There are rare nearshore marine and submarine channel sandstones and conglomerates. Porous and permeable sands and conglomerates occur in the upper 2000 m of the sedimentary succession. These sands and conglomerates occur as thin interbeds in the thick mudstone sequence. Although Shouldice (1971) and Yorath (1987) report low porosities as a result of clay mineral plugging, sidewall core samples retrieved from the six offshore wells drilled to date in the Tofino Basin and outcrop samples on the Olympic Peninsula of Washington in the Juan de Fuca sub-basin indicate fair to good porosity and permeability (Shell Canada Ltd. 1968f, g, h, i, 1969d, e; Snavely, 1987). Sidewall cores exhibit porosity values ranging from 20 to 46 per cent. Secondary porosity due to fracturing is probably minor in the basins. About 3 per cent of the total Tofino Basin succession consists of reservoir-quality strata.

In the Juan de Fuca sub-basin, turbiditic coarse grained clastic material is more widespread than in Tofino Basin. Niem and Snavely (1991) state that, in general, these matrix-rich rocks have low to moderate reservoir potential as a result of diagenetic and detrital clays and siliceous cements clogging the pores. Outcrops of Eocene–Oligocene lithic sandstones are typically characterized by moderate porosity and low permeability, averaging around 20% and 5 md., respectively. Rare, cleaner micaceous sandstones have improved reservoir quality, with measured values of up to 25% porosity and 657 md. permeability. However

Tertiary sections intersected in drillholes onshore indicate tight siltstones, mudstones and minor turbiditic sandstone. Minor secondary fracture porosity was observed in these holes (Niem and Snavely, 1991).

Pleistocene

Pleistocene turbidite sandstones likely occur in the Winona Basin and some may have reservoir potential. However, with no wells yet drilled in the basin, evaluation of reservoir characteristics remains equivocal.

Seals

Impermeable shales and siltstones dominate the Tertiary clastic succession in these basins. Thin reservoir lenticular sands abut against and are overlain by these fine grained rocks. Therefore, more than adequate seal is present throughout the succession in the basins. In the Juan de Fuca sub-basin, thick impermeable mudstone and shale units are interbedded with thin reservoir-quality sands. However, Niem and Snavely (1991) state that most of the north-dipping reservoir units of the homocline in the sub-basin have been breached by erosion, which increases the prospect-level risk for seal in this particular part of the basin.

Traps

Petroleum trap types in the Tofino Basin include simple anticlinal folds, faulted anticlines, normal and thrust faults and shale diapirs (Fig. 38, Table 3). Anomalously high geopressure gradients have been measured in the Tofino Basin (Shouldice, 1971). Injection of incompetent shales into overlying sediments due to pressure buildups produced the diapiric structures that provide potential sites for petroleum accumulation on the crest or along the flanks of the diapir. Episodic compressional folding and/or fault-related deformation occurred from mid-Miocene to Pleistocene time. Shale diapirism postdated the folding episodes. Very large structures are observed on available seismic lines. Closure areas vary from approximately 12 to 145 km^2, with an average closure of 25 km^2. Vertical closure on traps ranges from 20 to 1100 m. Structures occur throughout the stratigraphic succession. In the southern part of Tofino Basin, the Neogene sediments are essentially undeformed except at the shelf edge, where broad anticlines occur (Shouldice, 1971). In central Tofino Basin, curvilinear folds occur landward of the continental shelf (Fig. 38; Apollo anticline, Yorath, 1980). These anticlines are interpreted as having formed as a result of gravitational sliding along shallow detachment surfaces in Neogene and Quaternary sediments (Yorath, 1980).

The presence of isolated, lenticular sandstones within thick mudstone sections provides potential for stratigraphic traps within Tofino Basin. This trapping relationship has been documented by Niem and Snavely (1991) in the Juan de Fuca sub-basin.

Source rocks

Tertiary strata encountered in the offshore Tofino Basin have poor source rock potential. Strata penetrated by exploration wells are characterized by terrestrial Type III organic matter, with low organic content (avg. 0.8% TOC) and low Hydrogen Index (Bustin, 1995). Strata with somewhat different source rock characteristics have been identified along the margins of the Juan de Fuca sub-basin (Niem and Snavely, 1991). Tertiary mudstones and accretionary ("melange") sediments in this area, although still characterized by low organic content (<1% TOC), locally contain both Type III and (oil-prone) Type II organic material. A possibility exists that similar or richer source rocks may be present in parts of the accretionary wedge beneath the offshore Tofino Basin. The source rock characteristics of Winona Basin strata are unknown.

Source rock maturation

Organic maturation data (Rmax and vitrinite reflectance) from Tofino Basin wells indicate that Tertiary strata are immature to marginally mature, with the depth to the top of the oil window occurring at about 2000 m (Bustin, 1995; Fig. 41). In onshore areas of Juan de Fuca sub-basin, Tertiary strata vary from immature to mature, with highest maturation levels (vitrinite reflectance values of up to 0.75%) occurring in Eocene accretionary wedge sediments (Snavely, 1987; Niem and Snavely, 1991).

Timing of hydrocarbon generation

Maturation models indicate hydrocarbon generation in Tofino Basin probably occurred in the late Tertiary, both during and after late stages of basin development and trap formation, that is, folding (e.g., Fig. 42). As such, there should be relatively little risk associated with timing of hydrocarbon generation in most parts of Tofino Basin.

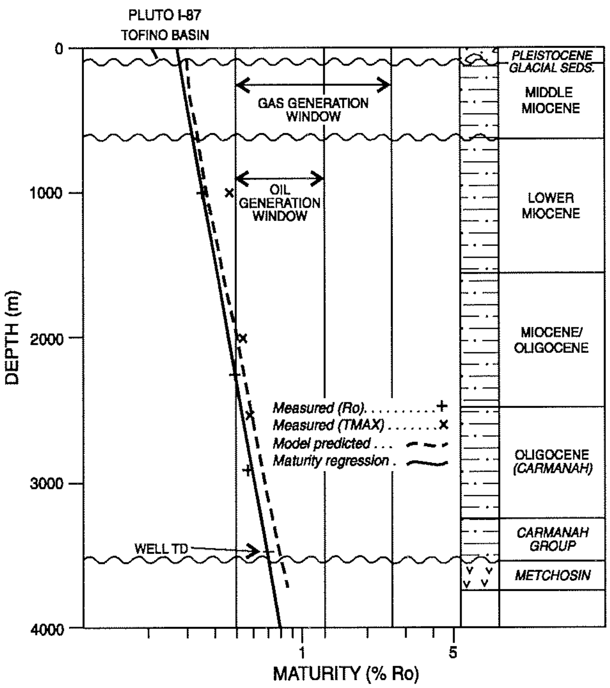

Figure 41. Maturation–depth profile of strata in the Shell Anglo Pluto I-87 well location, Tofino Basin (see Fig. 2 and Table 1 for well location). Measured subsurface Ro and TMAX values obtained from Bustin (1995). Model-predicted maturation profile based on illustrated stratigraphy and a constant geothermal gradient of 25 C/km. Uplift and erosion of 1500 m subsequent to deposition of Middle Miocene mudstones and siltstones is estimated by extrapolating measured maturation gradients. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995).

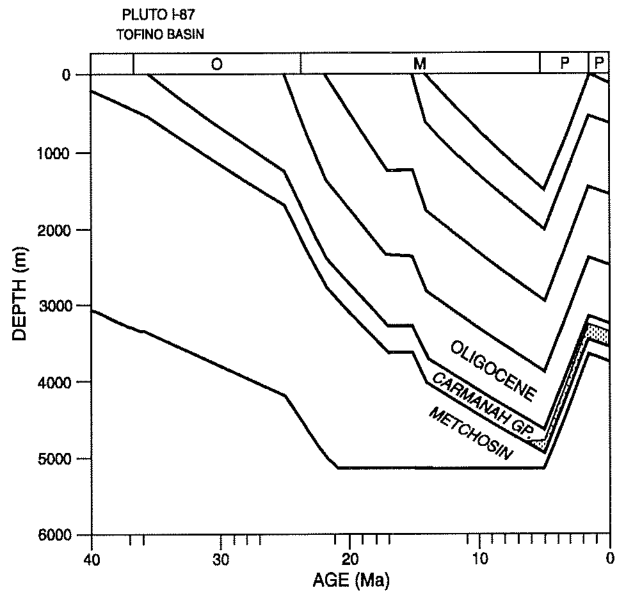

Figure 42. Subsidence and hydrocarbon generation model for area of Pluto I-87 well, Tofino Basin. Model derived from commercial basin modelling system, BasinMod 1-D (Platte River Associates, 1995). Hydrocarbon generation models based on standard (BasinMod) kinetic parameters for organic matter types (Type III for all Tertiary strata). See text for discussion.

Considered together, the known and expected variations in timing of hydrocarbon generation, trap development and source rock distributions indicate the complex geographic distribution of oil and gas accumulations within the region. Large hydrocarbon accumulations will probably be restricted to a small number of local areas or structures where optimum timing occurred between trap development and source rock maturation.

Hydrocarbon shows

Of the six offshore wells drilled in Tofino Basin, two encountered gas shows in shallow Neogene sandstones (Shouldice, 1971). One gas show was discovered in Tertiary sandstone among the four wells drilled onshore Olympic Peninsula (Juan de Fuca sub-basin). In addition, three surface gas seeps have been reported from the onshore Juan de Fuca sub-basin (Niem and Snavely, 1991). These gas seeps are believed to be thermogenic, with a source in underlying Tertiary melange sediments. Surface exposures of melange mudstones contain local indications of oil and gas.

Petroleum assessment

One all-encompassing conceptual gas play was identified for the western Vancouver Island offshore basins, including the Tofino and the Winona basins, and the Juan de Fuca sub-basin. Assessment computations were performed for natural gas only in the Tofino region of the West Coast. Oil assessments were not undertaken for these plays because geochemical data suggest the area is not likely oil-prone.

Petroleum play

Tofino Tertiary structural gas play

Play definition. The Tofino Tertiary gas play includes structural and stratigraphic traps in Tertiary and Quaternary strata in the Tofino and Winona basins and Juan de Fuca sub-basin. The play area covers the continental shelf offshore Vancouver Island and parts of the adjacent deep-water slope and Pacific basin (Figs. 2, 43). Western Juan de Fuca Strait and northwestern Olympic Peninsula are also included in the play.

Geology. Prospects include Tertiary or Quaternary sandstones in large compressional folds, shale-diapir-cored anticlines and reverse-fault structural traps. Isolated sandstones encased in thick mudstone sections provide opportunities for stratigraphic trap potential.

Exploration risks. The exploration risk for the Tofino Tertiary play was estimated at 0.09, with most of the risk associated with the presence of source rocks and the adequacy of migration pathways (Appendix I, Table I.10b).

Play potential. The median estimate of play potential is 266 billion m^3 of in-place gas and the mean value estimate of number of fields is 41 (Fig. 44, Table 4). The largest field in the play is estimated (at median value) to contain 25.9 billion m^3 of in-place gas.

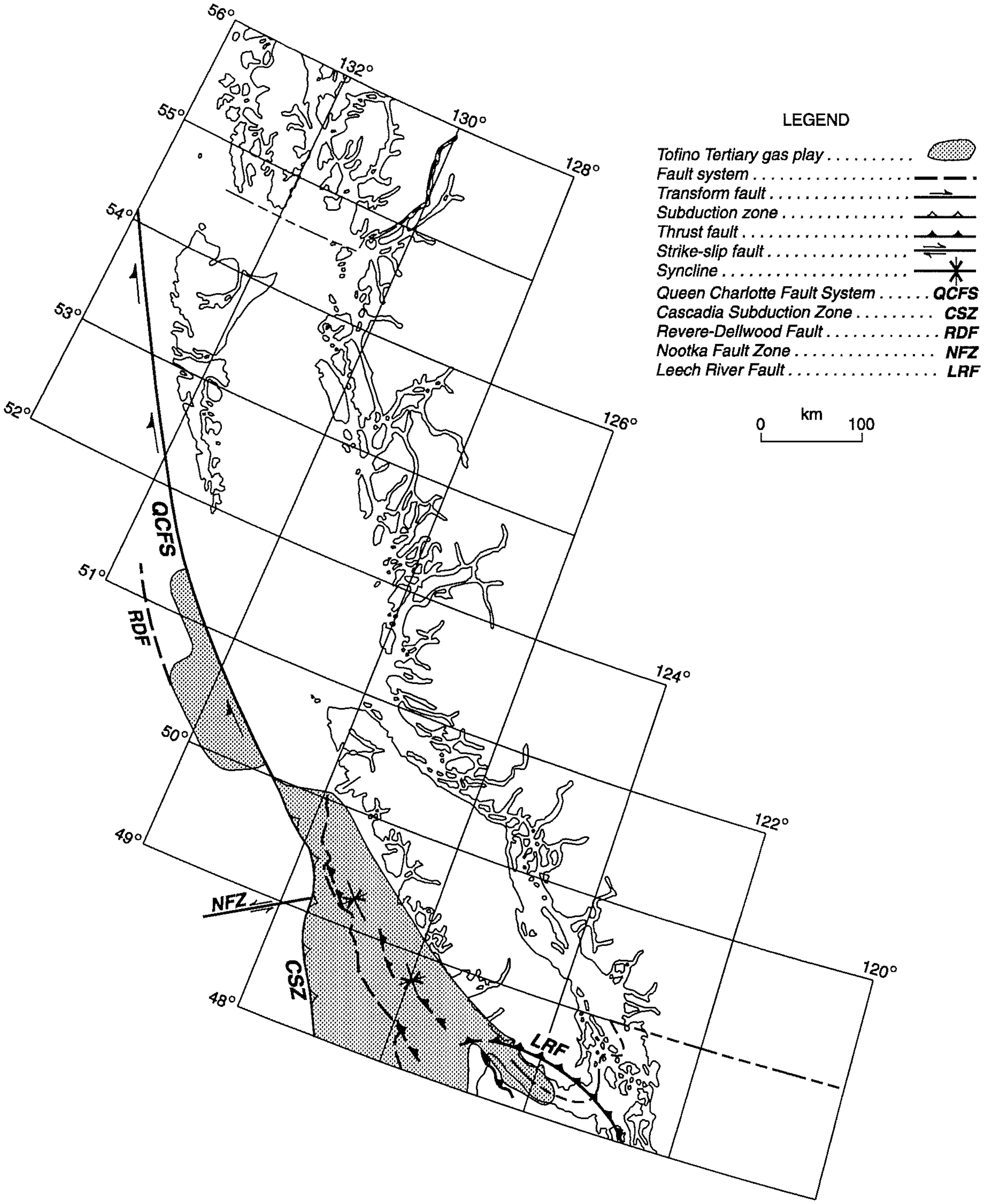

Figure 43. Tofino Basin Tertiary structural gas play area. Major structural elements are illustrated.

Discussion of assessment results

Resource distributions. One exploration play has been assessed for the combined Tofino–Winona–Juan de Fuca basin area. The gas volume predicted is 266 billion m^3 (9.4 Tcf) distributed in 41 fields (Fig. 44). The largest individual field is estimated to contain 26 billion m^3 (0.9 Tcf) of gas. Approximately 33 per cent of the region's total petroleum resource is concentrated in the five largest fields. This distribution indicates a moderate to low concentration of gas resource consistent with collisional convergent margin basins (Klemme, 1984).

The Juan de Fuca Strait area is considered the most prospective because of presence of source rock, greater volumes of coarse clastic sediments (potential reservoir facies), and known gas seeps. One well on the Olympic Peninsula reported a gas flow (1416 m^3/day). The Tofino Basin offshore Vancouver Island may be somewhat less prospective as a result of greater uncertainties regarding source and reservoir rocks. The Winona Basin and Accretionary Wedge are considered the least prospective parts of the Tofino assessment region.

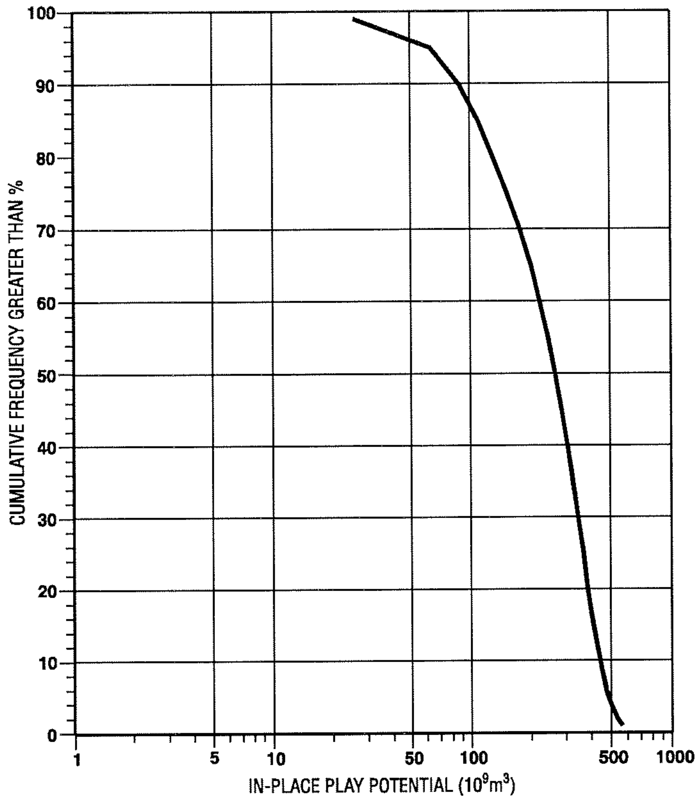

Figure 44. **Estimate of in-place gas potential of the Tertiary structural play in Tofino Basin region. Median value of probabilistic assessment is 266 billion m^3 of in-place gas distributed in 41 fields.**

Assessment results and exploration history. The exploration risk estimated suggests success rates for exploratory drilling in the region should average 1 in 11. The absence of commercial discoveries in 10 wells drilled to date does not preclude the presence of economically viable fields in the region. Because of an exploration moratorium imposed in 1972 on the federal lands in the Pacific offshore of Canada, only one well has been completed (Olympic Peninsula) since 1980. The introduction of sophisticated seismic techniques in the late 1970s contributed to locating this well; the only one with a significant gas flow to date. Ten wells represent evaluation of a very small fraction of the total prospective area within the three basins. As noted previously, it is common for many unsuccessful wells to be drilled in a frontier area before the first discovery is made.

Distribution of resources in Canada. Assuming an even distribution of gas potential resource in the play, roughly 85 per cent of the play is in Canadian jurisdiction. Therefore, about 253 million m^3 of gas may occur in Canada (median value).

BASIN COMPARISONS

The Queen Charlotte Basin region has been compared to the petroleum-producing Cook Inlet Basin (Haimala and Procter, 1982; Hamilton and Cameron, 1989; Thompson et al., 1991). Similarities between the two regions include the general ages and types of reservoir strata, source rocks, regional unconformities and structures, and common occurrences of surface hydrocarbon shows. The main difference between the two regions is in their Neogene structural history; the Cook Inlet Basin developed in a forearc setting and contains comparatively fewer strike–slip-related extensional faults than does the Queen Charlotte Basin. Total petroleum resources (produced and remaining) in the 20,000 km^2 Cook Inlet Basin are about 2.2 Bbbl of oil and 10 Tcf of gas (Magoon and Kirschner, 1990). Most of the Cook Inlet petroleum accumulations occur in Oligocene–Miocene conglomeratic sandstones within thrust faulted, Pliocene anticlines (similar to many Pliocene structures in the Queen Charlotte Basin). The largest individual oil and gas fields in Cook Inlet are the McArthur River field, with original oil reserves of 90 million m^3 (570 Mbbl), and the Kenai field, with original gas reserves of 65 billion m^3 (2.3 Tcf). These field sizes are of comparable magnitude to the median size estimates of the largest oil and gas fields predicted for the Queen Charlotte Basin.

Some debate has occurred concerning the tectonic setting for Georgia Basin. England and Bustin (1998) imply that Georgia Basin occupies the inner forearc position in the convergent margin plate tectonic model while Mustard (1994) proposed a foreland model for the Cretaceous Georgia Basin as a result of multiple source regions for the sedimentary succession and the presence of fold and thrust belts. The largest gas field of the eastern Cordilleran foreland fold and thrust belt comprises the Cretaceous gas pools of the Ricinus Field. The Cretaceous pools of this field have an initial in-place volume of 28,400 million m^3, comparable to the largest predicted field size for the Georgia Cretaceous play (31,977 million m^3). Comparing a proposed forearc Cretaceous Georgia Basin with the Cook Inlet Basin (forearc setting) reveals predicted largest field sizes less than half the size of the Kenai gas field (32 billion vs. 65 billion m^3). Analogous gas-bearing basins for the strike–slip pull-apart model proposed for Tertiary Georgia Basin are the Mackenzie Delta basin of northern Canada (Dixon et al., 1994) and the Willamette Basin of northern Oregon containing the Mist Field (Armentrout and Suek, 1985). Active underplating in the Tofino and Juan de Fuca Basin regions has produced local areas of normal, strike–slip and thrust faulting in the overlying sediments. Occasional thrust-faulted anticlines in the Tertiary succession reflect trap-forming structures analogous to similar circum-Pacific convergent margin forearc basins (Japan Trench; Aleutian Trench).

Other northeast Pacific region petroleum fields with past oil or gas production include three small onshore fields in Washington and Oregon. The commercial Mist Lake gas field was discovered in the forearc Willamette Basin of northern Oregon in 1979 (Armentrout and Suek, 1985). The Mist Lake gas reservoir occurs in Eocene quartzo-feldspathic sandstones with compositional and reservoir characteristics similar to Neogene sandstones in the Queen Charlotte and Georgia basins.

The Queen Charlotte Basin region has also been compared to the southern California continental borderland, based on similarities in Neogene tectonic history and structural characteristics (Rohr and Dietrich, 1992). Numerous petroleum-bearing Neogene strike–slip basins occur in the California borderland region, including the oil-rich Los Angeles Basin, with reserves of over 10 Bbbl (Biddle, 1992). Differences in types of petroleum source rocks in the California and Queen Charlotte basins preclude making direct petroleum endowment comparisons between the two regions. However, from a general perspective of basin types, strike–slip basins are known worldwide to be above average in hydrocarbon richness, on a sediment volume or area basis (Price, 1994). Factors that contribute to hydrocarbon enrichment in strike–slip basins include high paleo-heat-flow and extensive faulting of source and reservoir rocks, two features that characterize the Queen Charlotte Basin region. Tertiary Georgia Basin has some strike–slip basin characteristics (Mustard and Rouse, 1994) and may be comparable to some southern California basins in terms of structural styles.

There are no direct geological analogues for the British Columbia offshore region in other Canadian frontiers. However, by comparing the magnitude of resource estimates with other Canadian frontier regions, a ranking of potential can be achieved. Note that recoverable resources are quoted here for comparison purposes. Compared to the median recoverable resource estimate of 2.6 Bbbl of oil and 20 Tcf of gas in the

Queen Charlotte Basin region, median estimates of resource endowment for Canadian East Coast and Arctic basins include 4.7 Bbbl of oil and 13 Tcf of gas for the offshore Newfoundland Jeanne D'Arc Basin (Procter et al., 1983; Sinclair et al., 1992), 18 Tcf of gas and 1 Bbbl of oil/condensate for the Scotian Shelf Basin (Wade et al., 1989), and 7 Bbbl of oil and 68 Tcf of gas for the Beaufort–Mackenzie Basin (Dixon et al., 1994). Median resource estimates for recoverable gas in the Georgia Basin are 5.8 Tcf and in the Tofino Basin region 8.5 Tcf (recovery factor: 0.9). In comparing Canada's east and west coast basins, the present assessment indicates the Queen Charlotte Basin may have a gas resource endowment comparable to the Scotian Shelf Basin and an oil resource endowment about half that of the Jeanne D'Arc Basin. Gas resource estimates for the combined Tofino–Georgia basins are comparable to the Jeanne D'Arc Basin endowment.

CONCLUSIONS

The oil and gas resource potential of Canada's west coast basins has been evaluated through regional petroleum play assessments. The quantitative assessments were derived using the Geological Survey of Canada's (PETRIMES) assessment methodology system. The assessments included analyses of 10 conceptual plays, each of which incorporated the calculation or estimation of field size parametric data, numbers of prospects and exploration risks. Oil and gas volumes reported for these conceptual plays are total statistical estimates of the resource present 'in the ground', not the gas volume that is economically producible. Individual field-size determinations will be important in identifying which plays are attractive for exploration programs.

Median estimates for total oil and gas potential for all Canadian west coast basins are 1560 million m^3 of in-place oil and 1228 billion m^3 of in-place gas (Figs. 24, 45). In-place oil potential is restricted exclusively to the Queen Charlotte Basin region; gas potential encompasses all Canadian west coast basins.

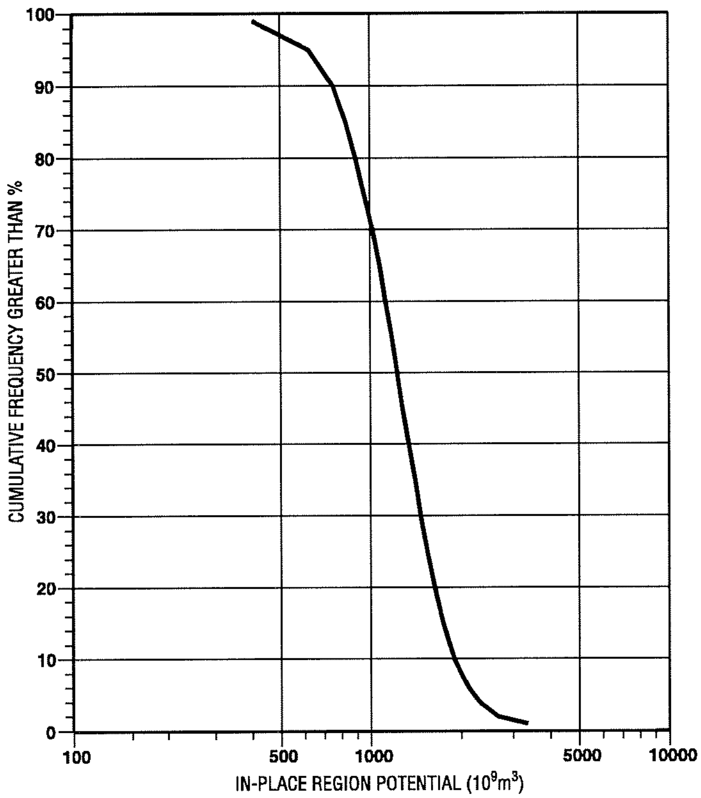

Figure 45. **Estimate of total gas potential for west coast basins. Median value of probabilistic assessment is 1228 billion m^3 of in-place gas.**

The potential for significant petroleum accumulations in the Queen Charlotte Basin and environs is indicated by the combined presence of abundant reservoir strata, good petroleum source rocks, numerous and diverse structural and stratigraphic traps and common occurrence of oil and gas shows. Quantitative assessments of six petroleum plays in the Queen Charlotte Basin region provide estimates of total resource potential of 1560 million m^3 (9.8 billion bbls.) of in-place oil and 734 billion m^3 (25.9 TCF) of in-place gas (median values). In terms of number of predicted fields and energy-equivalent volumes, estimated gas resources are more abundant than oil. The ranges of oil and gas estimates from high to low probability reflect the level of uncertainty in assessing petroleum potential for this region. However, in comparative terms, the estimates from the current assessment are substantially higher than those derived in the Geological Survey of Canada's 1982 assessment. The higher resource estimates in this assessment reflect several factors, including more optimistic evaluations of number of prospects, and volume and quality of potential reservoirs. In addition, the indications of a Jurassic-source Miocene reservoir petroleum system occurring offshore is considered significant, since large oil accumulations will probably occur as part of such a petroleum system.

Historical natural gas production from Pleistocene sands confirm the existence of petroleum accumulations within Georgia Basin. Although the ultimate play potential and field sizes are small for the Pleistocene play, sufficient favourable play conditions are present for significant gas accumulations in the Tertiary and Cretaceous sedimentary successions. The combination of ample reservoir-quality material, adequate gas source rock, and abundant petroleum-trapping configurations provide the necessary elements for potential petroleum accumulations. The total resource potential in the Georgia Basin is 185 billion m^3 (6.5 TCF) of in-place raw gas (median). Currently available geochemical information indicates there is probably little or no oil resource potential in the Georgia or Tofino basins.

The potential for gas resources in the Tofino Basin is indicated by gas seeps and gas shows in onshore portions of the basin on the Olympic Peninsula. The total potential for the Tofino Basin assessment region is estimated (at a median value) to be 266 billion m^3 (9.4 TCF) of in-place gas.

Significant upside potential for natural gas was recognized in three plays. The most attractive plays for natural gas exploration, in decreasing order in terms of potential and largest field size are: 1) the Queen Charlotte Pliocene play, 2) the Queen Charlotte Miocene play, and 3) the Tofino–Winona–Juan de Fuca Tertiary structural play. Oil plays, in decreasing order of potential, are: 1) the Queen Charlotte Miocene play, 2) the Queen Charlotte Pliocene play, and 3) the Queen Charlotte Cretaceous play.

This assessment provides a favourable geological basis for further petroleum evaluation and exploration in the British Columbia coastal region. The complex geology and anticipated high exploration risks associated with the plays suggest that considerable amounts of new seismic data and many exploration wells may be required to properly evaluate the region's oil and gas potential. The present assessment suggests substantial petroleum resources remain to be discovered in the sedimentary basins on the Pacific margin of Canada.

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APPENDIX I
INPUT DATA FOR PETROLEUM ASSESSMENTS

The following tables present the probability distributions of reservoir parameters, number of prospects, and marginal probabilities of geological risk factors used as input for the various conceptual statistical analyses discussed in this paper. These estimates are based on subjective opinion, partly constrained by reservoir data and information from analogous petroleum-bearing basins.

1. QUEEN CHARLOTTE CRETACEOUS OIL PLAY

Table I.1a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	2	50	100
Formation thickness	m	1	30	180	200
Porosity	decimal fraction	0.08	0.15	0.2	0.25
Trap fill	decimal fraction	0.1	0.3	0.8	1.0
Oil saturation	decimal fraction	0.5	0.65	0.75	0.8
Shrinkage factor	decimal fraction	0.65	0.80	0.9	0.95

Table I.1b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		X
Presence of reservoir facies	0.5		X
Adequate seal	0.8		X
Adequate timing	0.9		X
Adequate source	0.5		X
Adequate recovery	0.9		X
Adequate play conditions	0.95	X	

Table I.1c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	300	500	1000

2. QUEEN CHARLOTTE CRETACEOUS GAS PLAY

Table I.2a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	2	50	100
Formation thickness	m	1	30	180	200
Porosity	decimal fraction	0.08	0.15	0.2	0.25
Trap fill	decimal fraction	0.05	0.2	0.7	0.9
Gas saturation	decimal fraction	0.5	0.65	0.75	0.8
Formation volume factor	decimal fraction	0.002	0.004	0.009	0.01

Table I.2b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		X
Presence of reservoir facies	0.5		X
Adequate seal	0.8		X
Adequate timing	0.9		X
Adequate source	0.4		X
Adequate recovery	0.9		X
Adequate play conditions	0.95	X	

Table I.2c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	300	500	1000

3. QUEEN CHARLOTTE MIOCENE OIL PLAY

Table I.3a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	3	100	300
Formation thickness	m	100	300	800	1000
Porosity	decimal fraction	0.1	0.25	0.3	0.35
Trap fill	decimal fraction	0.01	0.05	0.2	0.25
Oil saturation	decimal fraction	0.5	0.65	0.75	0.8
Shrinkage factor	decimal fraction	0.65	0.80	0.9	0.95

Table I.3b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		X
Presence of reservoir facies	0.9		X
Adequate seal	0.9		X
Adequate timing	0.8		X
Adequate source	0.4		X
Adequate preservation	0.7		X
Adequate recovery	0.9		X
Adequate play conditions	0.9	X	

Table I.3c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	90	300	400

4. QUEEN CHARLOTTE MIOCENE GAS PLAY

Table I.4a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	3	100	300
Formation thickness	m	100	300	800	1000
Porosity	decimal fraction	0.1	0.25	0.3	0.35
Trap fill	decimal fraction	0.01	0.05	0.2	0.25
Gas saturation	decimal fraction	0.5	0.65	0.75	0.8
Formation volume factor	decimal fraction	0.002	0.004	0.009	0.01

Table I.4b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		X
Presence of reservoir facies	0.9		X
Adequate seal	0.9		X
Adequate timing	0.8		X
Adequate source	0.5		X
Adequate preservation	0.8		X
Adequate recovery	0.9		X
Adequate play conditions	0.9	X	

Table I.4c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	90	300	400

5. QUEEN CHARLOTTE PLIOCENE OIL PLAY

Table I.5a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	5	150	300
Formation thickness	m	200	700	1200	1500
Porosity	decimal fraction	0.15	0.28	0.35	0.38
Trap fill	decimal fraction	0.01	0.02	0.2	0.25
Oil saturation	decimal fraction	0.5	0.65	0.75	0.9
Shrinkage factor	decimal fraction	0.65	0.80	0.9	0.95

Table I.5b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.8		X
Adequate seal	0.7		X
Adequate timing	0.5		X
Adequate source	0.4		X
Adequate recovery	0.9		X
Adequate play conditions	0.7	X	

Table I.5c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	40	200	300

6. QUEEN CHARLOTTE PLIOCENE GAS PLAY

Table I.6a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	5	150	300
Formation thickness	m	200	700	1200	1500
Porosity	decimal fraction	0.15	0.28	0.35	0.38
Trap fill	decimal fraction	0.01	0.02	0.2	0.25
Gas saturation	decimal fraction	0.5	0.65	0.75	0.8
Formation volume factor	decimal fraction	0.0025	0.005	0.009	0.01

Table I.6b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.8		X
Adequate seal	0.7		X
Adequate timing	0.6		X
Adequate source	0.6		X
Adequate recovery	0.9		X
Adequate play conditions	0.9	X	

Table I.6c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	40	200	300

7. GEORGIA CRETACEOUS STRUCTURAL GAS PLAY

Table I.7a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	10	50	60
Formation thickness	m	10	60	200	250
Porosity	decimal fraction	0.03	0.05	0.12	0.15
Trap fill	decimal fraction	0.01	0.2	0.5	1.00
Gas saturation	decimal fraction	0.5	0.75	0.9	0.95
Formation volume factor	decimal fraction	0.002407	0.004211	0.019051	0.02

Table I.7b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.75		X
Presence of porosity	0.2		X
Adequate seal	0.95		X
Adequate source	0.9		X
Adequate play conditions	0.75	X	

Table I.7c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	60	450	900

8. GEORGIA TERTIARY STRUCTURAL GAS PLAY

Table I.8a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	10	50	60
Formation thickness	m	1	15	20	30
Porosity	decimal fraction	0.08	0.15	0.34	0.37
Trap fill	decimal fraction	0.0	0.1	0.2	1.00
Water saturation	decimal fraction	0.1	0.1	0.1	0.1
Formation volume factor	decimal fraction	0.002	0.004	0.019	0.02

Table I.8b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.75		X
Presence of porosity	0.9		X
Adequate seal	0.85		X
Adequate play conditions	0.98	X	

Table I.8c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	60	150	300

9. GEORGIA PLEISTOCENE STRATIGRAPHIC GAS PLAY

Table I.9a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	0.1	0.3	0.5	1.5
Formation thickness	m	1	11	20	30
Porosity	decimal fraction	0.1	0.25	0.32	0.37
Trap fill	decimal fraction	0.5	0.75	0.9	1.00
Gas saturation	decimal fraction	0.01	0.25	0.9	1.0
Formation volume factor	decimal fraction	0.05	0.07	0.1	0.5

Table I.9b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.9		X
Presence of porosity	0.9		X
Adequate seal	0.5		X

Table I.9c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	10	200	500

10. TOFINO TERTIARY STRUCTURAL GAS PLAY

Table I.10a
Probability distributions of reservoir parameters

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	0.5	0.01	0.0
Area of closure	km^2	1	25	145	200
Formation thickness	m	20	200	500	1100
Porosity	decimal fraction	0.07	0.15	0.21	0.32
Trap fill	decimal fraction	0.01	0.05	0.1	0.15
Gas saturation	decimal fraction	0.5	0.8	0.9	0.95
Formation volume factor	decimal fraction	0.002	0.006	0.011	0.012

Table I.10b
Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.6		X
Presence of reservoir facies	0.6		X
Presence of porosity	0.9		X
Adequate seal	0.9		X
Adequate source	0.3		X

Table I.10c
Probability distribution for number of prospects

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	0.5	0.0
Number of prospects	100	500	800