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Petroleum Geology of the State of Washington

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ABSTRACT

Washington is a petroleum exploration frontier, but there is no current petroleum production in the State. Several possible petroleum systems may be present, hosted by sedimentary rocks deposited in Eocene strike-slip basins and late Eocene and younger intra-arc, fore-arc, and trench basins. Eight conventional petroleum plays, three coal-bed gas plays, and two continuous-type gas plays are delineated in order to analyze and assess the resource potential. In these plays, the potential for significant petroleum accumulations appears greatest in the Columbia Plateau region of eastern Washington. Potential accumulations in western Washington are smaller but could have local economic significance. On a regional scale, the absence of high-quality source rocks is probably the most important factor limiting development of large accumulations, although development of suitable reservoirs and an inability to map traps also limits the potential of some plays.

INTRODUCTION

There is no current oil and gas production in Washington. However, the region has been considered a petroleum frontier since 1900 when the State's first wildcat well was drilled in Snohomish County (McFarland, 1983). The State has experienced several phases of petroleum exploration during this century, generated largely by the presence of voluminous deltaic and marine sedimentary rocks, numerous oil and gas shows and seeps, and the development of the nearby Mist gas field in northwest Oregon (Niem and others, 1994). As part of an ongoing effort to understand and predict the petroleum resources of the United States that includes the recent National Assessment of Oil and Gas Resources (Gautier and others, 1995), the U.S. Geological Survey, in cooperation with the Washington Department of Natural Resources, recently recognized several hypothetical, conventional, and unconventional petroleum plays (Johnson and Tennyson, 1995). The play areas occupy diverse geologic

settings within the complex geologic framework of the Pacific Northwest convergent continental margin. The purpose of this report is to more fully describe, illustrate, and reference the geologic setting and petroleum geology of these plays and to briefly summarize resource estimates of the U.S. Geological Survey's 1995 National Petroleum Assessment. The play number designations used in that assessment are included in this report.

For eight hypothetical conventional petroleum plays in the State of Washington, we estimate a mean undiscovered petroleum resource of 586 BCF (billion ft³) of gas and 19.3 MMB (millions of barrels) of oil. Mean estimated potential gas-reserve additions from three hypothetical coal-bed gas plays are 697.3 BCF. The mean undiscovered petroleum resource estimated for one hypothetical basin-centered gas play (Columbia Basin—Basin-Centered Gas play, 503) is 12.2 TCF (trillion ft³) of gas and 122.0 MMB of natural gas liquids. A second basin-centered gas play (Willamette—Puget Sound Basin-Centered Gas play, 412) is described but not assessed because of insufficient information. Because petroleum is not currently produced in Washington and there is an enormous volume of untested sedimentary rock, there are fewer constraints on petroleum assessments than for developed regions and States. The play identification and analysis presented in this report provides a geologic database, framework, and references from which further discussion and evaluation of assessments can proceed.

All of the plays we have identified share a common set of geologic parameters. Most potential source and reservoir strata are Paleogene siliciclastic rocks. The source rocks range from carbonaceous shales and siltstones, having 0.5 to 4 percent total organic carbon, to methane-rich coals. Kero-

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gens are mostly type III gas prone, but minor amounts of type-II oil- and gas-prone material have been observed in some plays. Numerous gas shows and seeps together with stripper oil and gas production indicate that effective source rocks are present. Reservoir rocks are mostly Eocene moderate- to low-porosity feldspathic to sublithic sandstones, typically 20 to 60 ft (6.1 to 18.3 m) thick, with permeabilities ranging from a few tenths to a few tens of millidarcies. Wire-line logs indicate that many wells have penetrated multiple potential reservoirs and considerable impermeable mudstone; therefore inadequate seal is not considered an impediment to exploration. Thermal maturity typically decreases westward and eastward from low-grade metamorphic rocks that crop out along the crest of the Cascade Range and in the core of the Olympic Mountains (fig. 1). Geothermal gradients along the Puget trough have apparently remained at a low 15°C/km since the middle Eocene. Potential fault traps and faulted anticlinal traps are abundant throughout Washington, but structural complexity coupled with various data-collection problems have stymied most efforts to map prospect-scale structures with reflection seismology. All plays described can be considered as frontier exploration. As of 1995, the average drilling density in Washington was among the lowest in the United States, with about 1 well per 1,000 mi² (2,600 km²).

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REGIONAL GEOLOGY OF WASHINGTON

Washington (fig. 1) occupies a complex geologic setting along the western continental margin of North America. Much of the State is underlain by a diverse pre-Tertiary basement of metamorphic, igneous, and sedimentary rock that comprise several distinct crustal terranes that generally have allochthonous and (or) exotic origins (e.g., Tabor, 1994). Final stages of accretion of these terranes occurred by Late Cretaceous or Paleogene time, after which the rocks formed the framework of the Washington continental margin. These rocks are widely exposed in northeastern Washington and the

North Cascade Range. In southeastern Washington, this basement complex is covered by the Miocene Columbia River Basalt Group. In the Cascade Range, pre-Tertiary rocks plunge south below Tertiary Cascade volcanic rocks about 28 mi (46 km) southeast of Mount Rainier. The westernmost exposures of pre-Tertiary basement rocks occur in the San Juan Islands and along the west flank of the Cascade Range. For the most part, these pre-Tertiary rocks are thought of as economic basement for petroleum exploration in Washington.

The pre-Tertiary basement experienced significant Eocene transtensional and extensional deformation, manifested by detachment faulting and diffuse volcanism in northeastern Washington (e.g., Harms and Price, 1992), and strike-slip faulting and formation of rapidly subsiding sedimentary basins in the area of the present Cascade Range and western Columbia Plateau (Johnson, 1985). Thick sequences of Paleocene to lower Oligocene fluvial to shallow-marine sandstone and interbedded mudstone and coal are widespread throughout Washington (fig. 2). For example, Eocene nonmarine sedimentary rocks exceed 20,000 ft (6,000 m) in thickness in the northwest-trending Chiwaukum graben (Gresens and others, 1981; Chumstick basin of Evans, 1994) on the east flank of the Cascades and in the Bellingham basin of northwest Washington (Johnson, 1984a). The thick Paleogene sedimentary sequences in these basins may be host to petroleum. Four hypothetical conventional gas plays (fig. 3), three hypothetical coal-bed gas plays (fig. 4), and a hypothetical basin-centered gas accumulation play (fig. 4) that involve these rocks are described below.

The Paleogene sedimentary rocks in the Cascade Range-Columbia Plateau region are partly covered by younger volcanic rocks. Cascade arc volcanism began in the late Eocene and, although discontinuous in both space and time, has persisted until the present. In contrast, the thick (as much as 15,000 ft; 4,572 m) Miocene Columbia River Basalt Group, which covers southeastern Washington, was erupted from feeder dikes in easternmost Washington and Oregon and adjacent Idaho in a relatively short period between about 16.5 and 6.5 Ma (Walsh and others, 1987; Reidel and others, 1989).

Pre-Tertiary basement in Washington is bounded on the west-southwest by a complex structural zone in the Puget Lowland (Johnson and others, 1996). West of this zone, the western Puget Lowland, Coast Range, and Olympic Mountains of Washington are mainly underlain by lower and middle Eocene marine basalts of the Crescent Formation, now widely believed to have formed in a continental-margin rift-basin setting (Wells and others, 1984; Snavelly, 1984, 1987; Babcock and others, 1992). In the late Paleogene and Neogene, significant local tectonism and block rotation led to partitioning of southwest Washington into discrete basins and uplifts (Wells and Coe, 1985). One hypothetical gas play (fig. 3; Cowlitz-Spencer Gas play, 407) involving middle to upper Eocene marine to nonmarine rocks overlying the

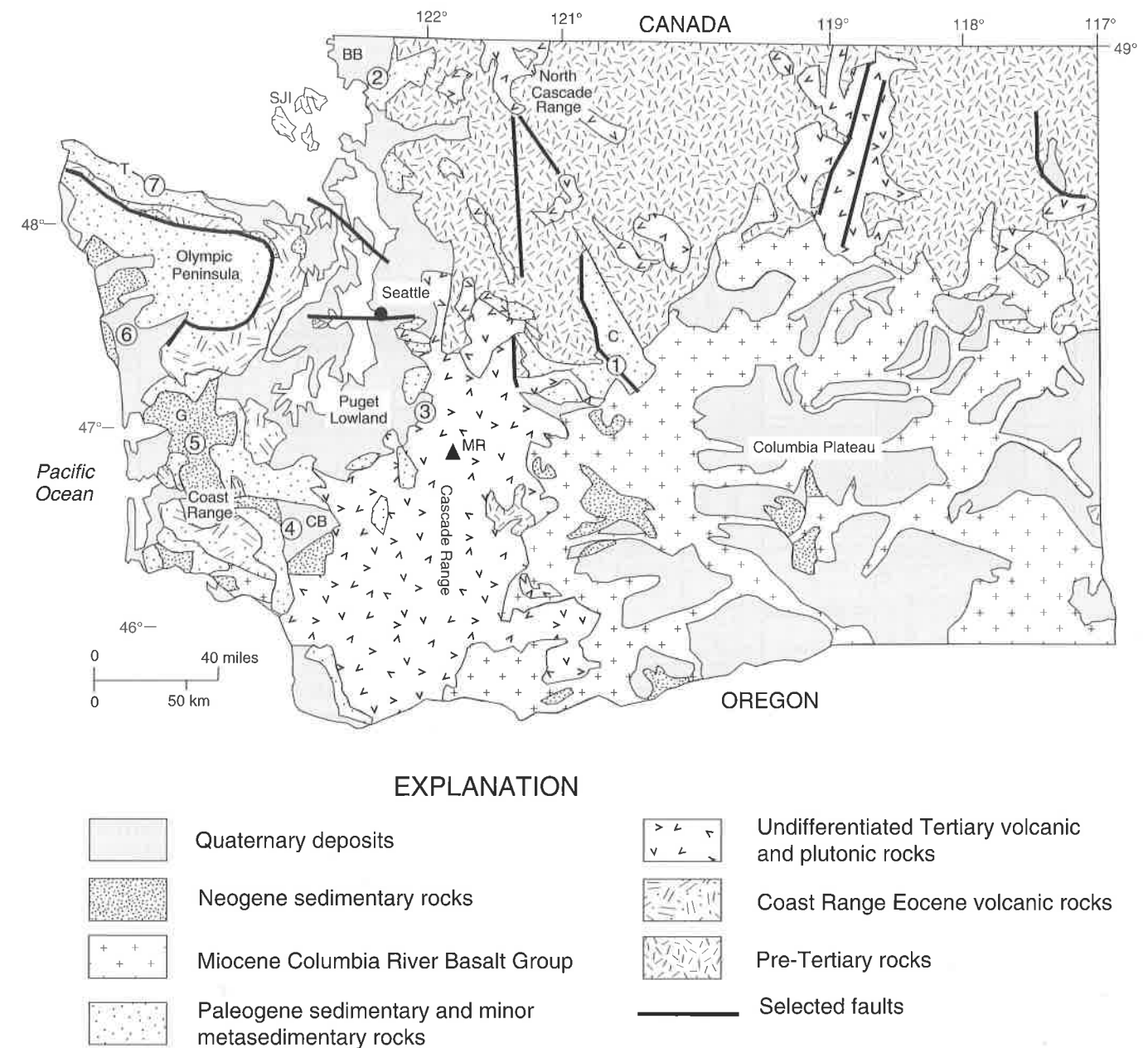


Figure 1. Schematic geologic map of Washington, modified from Schuster (1992). Numbers refer to locations of stratigraphic columns shown in figure 2. BB, Bellingham basin; C, Chumstick basin; SJI, San Juan Islands; MR, Mount Rainier; CB, Chehalis basin; G, Grays Harbor basin; T, Tofino-Fuca basin.

Crescent Formation is located in the Chehalis and Nehalem basin areas on the eastern flank of the Coast Range block in southwest Washington. A hypothetical oil play involving Miocene shallow-marine sandstones (fig. 3; Southwest Washington Miocene Sandstone play, 406) occurs in the Grays Harbor basin area on the western flank of the Coast Range block in southwest Washington.

Throughout the Tertiary, the Coast Range block moved northward relative to the pre-Tertiary framework to the east along a complex dextral strike-slip fault zone on its eastern margin (Johnson, 1984b, 1985; Johnson and others, 1994, 1996). This northward movement has been accommodated

on the north by south-directed thrusting on southern Vancouver Island (Clowes and others, 1987), by folding and faulting in the northern Coast Range block (Brown and others, 1960; Snavelly, 1987; Snavelly and others, 1993), and by subsidence of the Tofino-Fuca basin (Johnson and Yount, 1992). Eocene to Miocene marine sedimentary rocks of the Tofino-Fuca basin on the northern Olympic Peninsula are host to one hypothetical gas play (fig. 3; Tofino-Fuca Basin Gas play, 404), described below.

Subduction of oceanic crust and overlying marine sediment below the western margin of the Coast Range block has occurred from the Eocene to the present. Underplated

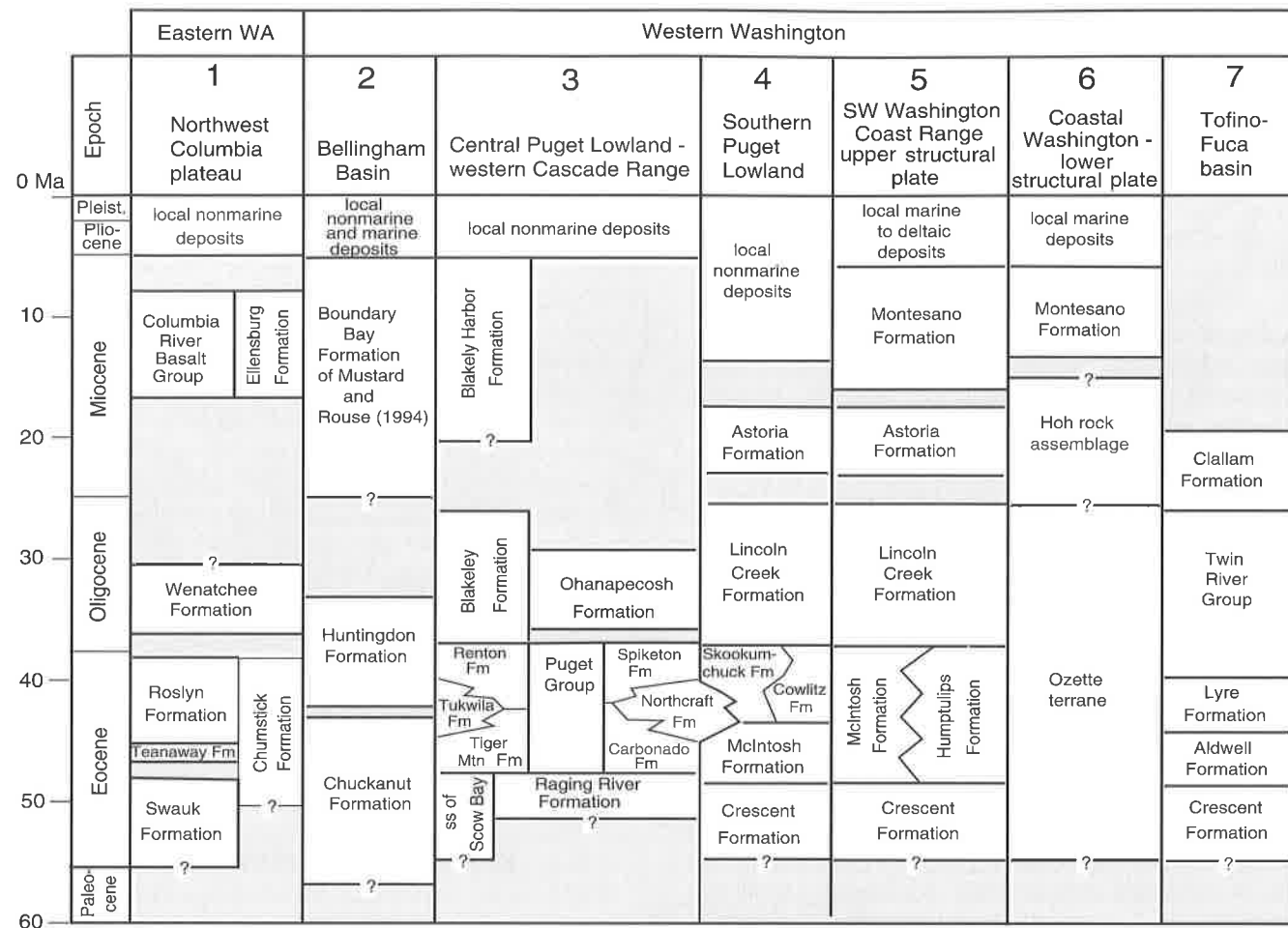


Figure 2. Correlation chart showing stratigraphy in petroleum-play areas. Shaded areas show intervals of nondeposition and (or) erosion. References for columns include: (1) Tabor and others (1982, 1984), Taylor and others (1988), Evans and Johnson (1989); (2) Johnson (1984a), Mustard and Rouse (1994); (3) Frizzell and others (1983), Frizzell and Easterbrook (1983), Johnson and others (1994); (4) Snavely and others (1958), Rau and others (1983); (5) Rau and Armentrout (1983), Rau (1986), Moothart (1992); (6) Rau (1973), Palmer and Lingley (1989), Snavely and others (1993); (7) Snavely and Lander (1983).

sedimentary rocks varying in character from chaotic melange to thick, laterally continuous sections, exposed by dramatic late Miocene and younger uplift, crop out in the Olympic Mountains and along the adjacent coastline to the west (Tabor and Cady, 1978; Brandon and Calderwood, 1990; Snavely and others, 1993; Lingley, 1995). These variably deformed rocks are host to the hypothetical Western Washington Melange play (405) and may be sources for petroleum in the Tofino-Fuca Basin Gas play (404) and the Southwest Washington Miocene Sandstone play (406) (fig. 3).

CONVENTIONAL PETROLEUM PLAYS

For the U.S. Geological Survey 1995 National Assessment of United States Oil and Gas Resources (Gautier and others, 1995), a conventional petroleum play was defined as "a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal

properties such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type" (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995, p. 6). Play attributes are the geologic characteristics that describe principal properties of and necessary conditions for the occurrence of oil and (or) gas accumulations of a minimum size. Minimum accumulation sizes estimated and evaluated quantitatively for the National Assessment are 1 MMBO (million barrels of oil) and 6 BCFG (billion cubic feet of gas). Assessments of undiscovered fields smaller than these minimum accumulations were made separately. For each conventional play defined, there is a discussion of source rocks, reservoir, timing and migration of hydrocarbons, traps and seals, exploration status, and evaluation of resource potential. The exploration status describes historical drilling activity and known industry interest as of 1995.

Evaluation of conventional resource potential is based on probabilities of play attributes, including *charge*, *reservoir*, and *trap*. *Charge* describes the occurrence of conditions

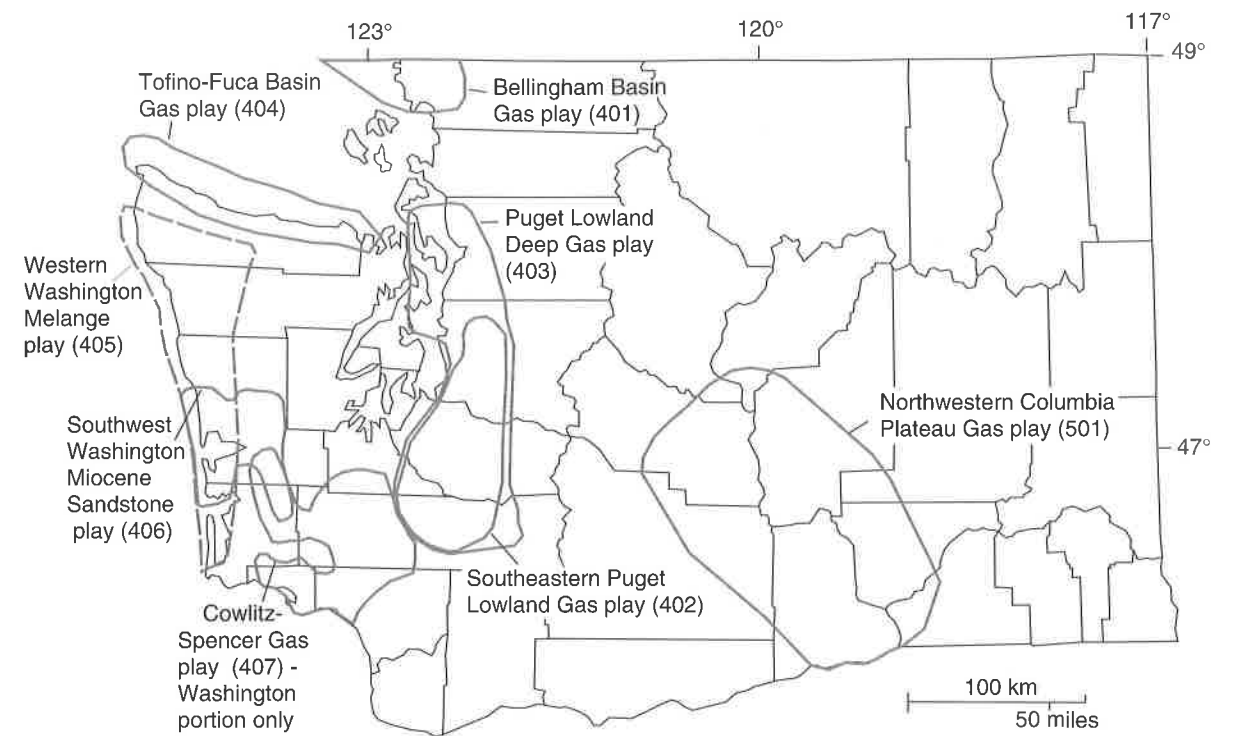


Figure 3. Map of Washington showing locations and boundaries of conventional petroleum plays.

of hydrocarbon generation and migration adequate to cause an accumulation of the minimum size. *Charge* includes consideration of the existence of source rocks that contain sufficient organic matter of the appropriate composition, appropriate temperature and duration of heating to generate and expel sufficient quantities of oil and (or) gas, and timing of expulsion of oil and gas from source rocks appropriate for filling available traps. *Reservoir* considers the occurrence of reservoir rocks of sufficient quantity and quality to permit the containment of oil and (or) gas in volumes sufficient for an accumulation of the minimum size. *Trap* considers the occurrence of those structures, pinch-outs, permeability changes, and similar features necessary for the entrapment of oil and (or) gas in at least one accumulation of the minimum size. Included in this attribute are seals sufficient for entrapping hydrocarbons and capable of holding oil and gas accumulations during appropriate ranges of geologic time. The *play probability* represents the product of the probabilities (expressed as a decimal fraction) of the three play attributes (charge, reservoir, and trap) and represents the chance that oil or natural gas accumulations of the minimum size exist within the particular play. Only plays with play probabilities of greater than 0.1 were quantitatively evaluated.

After first determining an acceptable (≥ 0.1) play probability, estimates were made of the minimum, median, and maximum number of undiscovered accumulations in the area of each play. These estimates were based on the size of the play area, our interpretation of the geology of the play, and analogs from other fields, plays, and provinces. We also estimated the size distribution of accumulations in the play.

These estimates are based on either a geologically similar analog or on equations for in-place hydrocarbons (e.g., Dolton and others, 1987) that involve several different parameters and assumed values that are listed for each play.

BELLINGHAM BASIN GAS PLAY (401)

Introduction.—This hypothetical conventional gas play is located in the Bellingham basin of the northern Puget Lowland of Washington (figs. 1, 3, 5). The Bellingham basin is a lowland that forms the southern part of a larger topographic depression that extends northwest into Canada. Initial subsidence in the Georgia basin is recorded by marine and lesser nonmarine conglomerate, sandstone, siltstone, and shale of the Upper Cretaceous Nanaimo Group (Mustard, 1994). A second phase of basin subsidence is recorded by nonmarine sandstone, mudstone, and coal of the Paleocene(?) to Eocene Chuckanut and the upper Eocene Huntingdon Formations (fig. 2) (Johnson, 1984a; Mustard and Rouse, 1994), which rests unconformably on the Nanaimo Group or on pre-Tertiary crystalline or metamorphic basement. The modern Georgia and Bellingham basins formed in the Neogene following a significant middle Tertiary contractional deformation event (Johnson, 1984a; England and Calon, 1991). The modern Bellingham basin contains a dominantly continental sedimentary sequence of Miocene to Quaternary sediments, including the Boundary Bay formation of Mustard and Rouse (1994), Pleistocene glacial and interglacial sediments, and fluvial-deltaic deposits of the Fraser and Nooksack rivers.

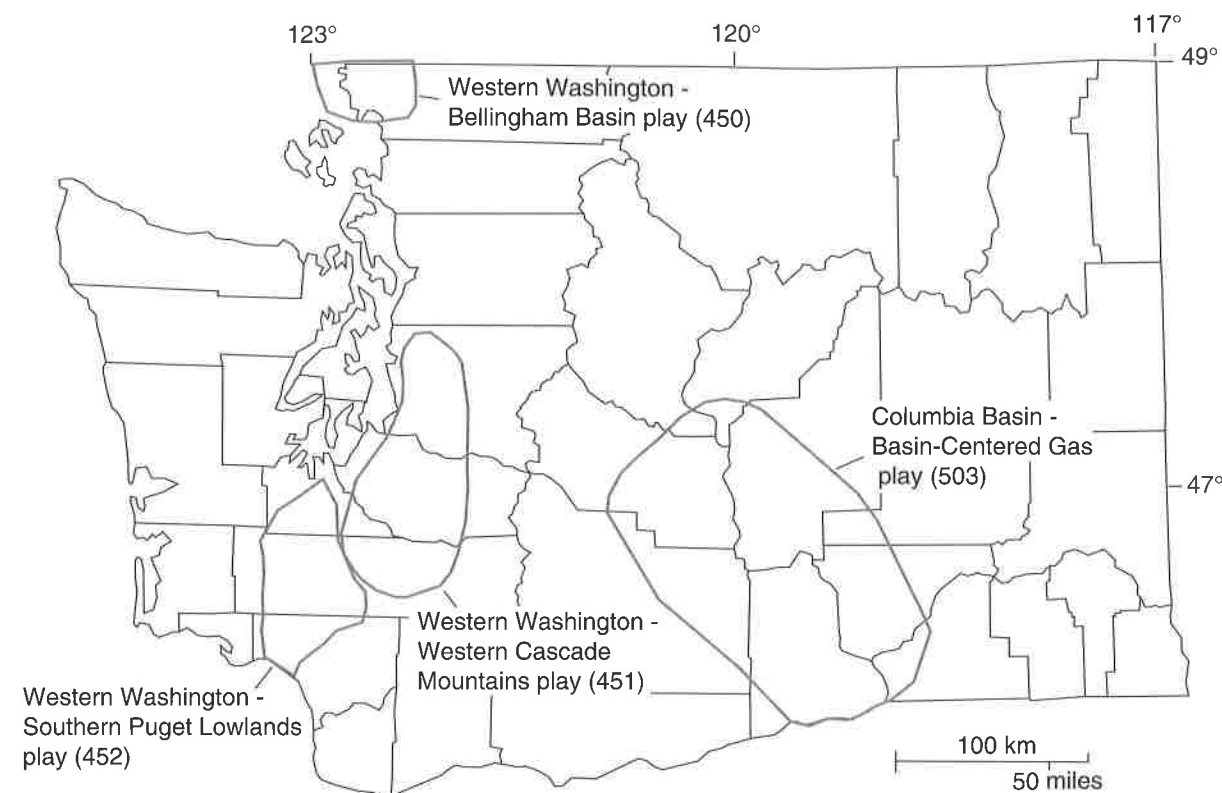


Figure 4. Map of Washington showing locations and boundaries of unconventional petroleum plays.

The Bellingham Basin Gas play (401) is bounded to the south by uplifted, folded strata of the Eocene Chuckanut Formation and to the east by an uplift of pre-Tertiary basement rocks on Sumas Mountain. To the southwest, the play extends into the Strait of Georgia and is bounded by pre-Tertiary rocks of the San Juan Islands. To the north (both onshore and offshore), the play extends into Canada. Only the portion of the play in the United States is evaluated in this report.

The petroleum exploration premise for this play is that gas has been generated from organic-rich nonmarine rocks of the Eocene Chuckanut Formation, or less likely from Upper Cretaceous marine strata of the Nanaimo Group, and migrated into reservoirs in Chuckanut fluvial sandstone bodies. Structural traps for reservoirs might include large folds or smaller fault blocks, and interbedded fine-grained rocks would provide seals.

Reservoirs.—Potential reservoirs in the Bellingham Basin Gas play (401) are the lower and middle Eocene fluvial and distributary channel sandstone bodies of the Chuckanut Formation (Johnson, 1982, 1984c). Sandstone bodies range in thickness to as much as 200 ft (60 m), are commonly conglomeratic, and typically include thin (< 1 ft; 30 cm) discontinuous lenses of mudstone. Sandstone bodies are bounded by fine-grained strata (mudstone to very fine grained sandstone) of fluvial overbank origin. In samples from the Birch Bay No. 1 well, porosity decreased with depth from 26

percent at 1,000 ft (305 m) to less than 10 percent at 6,000 ft (1,829 m) (Hurst, 1991). Permeable reservoir rocks may be present below about 4,500 ft (1,372 m) locally, but not across the entire play. Measured permeabilities range from less than 1 mD to 58 mD (P.D. Hurst, Canadian Hunter Exploration, Ltd., written commun., 1992). Sandstones are arkosic arenites (Johnson, 1982, 1984a) and the decreases in reservoir qualities with depth are attributed to compaction and degradation of feldspar and lithic fragments. Porosity values from 20 outcrop samples of Chuckanut Formation sandstone range from 0.8 to 12.7 percent (mean = 7.01 percent); permeability values for the same sample suite ranges from 0.002 to 2.89 mD (mean = 0.326 mD) (J.M. Armentrout, Mobil Oil Company, written commun., 1982).

Source rocks.—The character of source rocks in the Upper Cretaceous Nanaimo Group is considered poor (Bustin, 1990; Bustin and England, 1990; Mustard, 1994). Non-marine carbonaceous shale and coal beds of the lower Tertiary Chuckanut and Huntingdon Formations have moderate gas generative potential although these rocks are immature in many parts of the basin. In the Birch Bay No. 1 well (addendum to McFarland, 1983), for example, coals and shales above a depth of 6,000 ft (1,829 m) are reported to have both type-III and -IIB kerogens (Lingley and von der Dick, 1991), and several beds in this interval contain more than 6 percent total organic carbon (Hurst, 1991). Rocks below 6,000 ft depth (1,829 m) in the Birch Bay No. 1 well

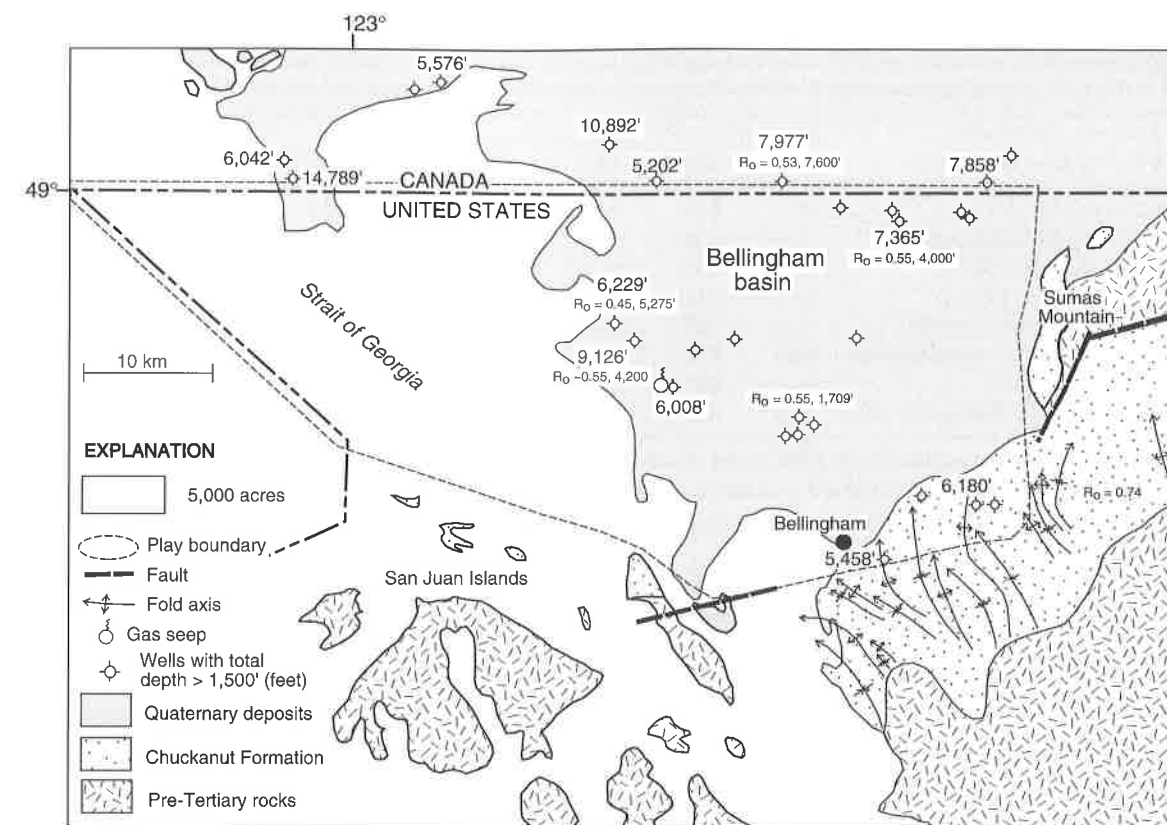


Figure 5. Schematic map showing Bellingham Basin Gas play (401). Petroleum wells in the United States are listed in McFarland (1983) or in addendum to McFarland available through the Washington Division of Geology and Earth Resources. Petroleum wells in Canada are listed in Mustard and Rouse (1994). Thermal maturity data (R_o = mean vitrinite reflectance) is from Hurst (1991, and written commun. 1992) and Walsh and Lingley (1991); values are from surface samples unless footage from adjacent petroleum well is listed. Geology greatly simplified after Johnson (1982) and Brandon and others (1988).

have type-III kerogens and low TOC (total organic carbon) values.

Vitrinite reflectance values of about 0.5 to 0.6 percent have been reported from depths of 1,700 to 7,600 ft (518 to 2,316 m) in the basin (fig. 5). Reflectance in Chuckanut Formation outcrops on the south flank of the Bellingham basin is 0.74 percent (fig. 5) (Walsh and Lingley, 1991).

Gases escaping from old well casings (about 5 mi northwest of Bellingham; fig. 5) have a high methane and nitrogen content (McFarland, 1983) and a mainly thermogenic origin (Hurst, 1991). One abandoned well is presently venting about 10 MCFGPD (thousand cubic feet of gas per day) because it cannot be effectively plugged.

Timing and migration of hydrocarbons.—Maximum burial occurred in the late middle to early late Eocene, prior to late Eocene folding and associated uplift (Johnson, 1984a). Thus, the large anticlines in the basin that are potential hydrocarbon traps formed during and slightly later than peak hydrocarbon generation and migration.

Traps and seals.—Large anticlines that are probably subsurface extensions of folds exposed on the southeastern basin flank (fig. 5) form the most viable hydrocarbon traps.

Hurst (1991) calculated 5,000 acres (20.2 km²) of structural closure on the anticline penetrated by the Birch Bay No. 1 well. Surface trends suggest there should be three or four comparable anticlines east of the Birch Bay structure in the basin subsurface. The basin is also cut by numerous high-angle faults (Johnson, 1982; Mustard, 1994), and small structural traps adjacent to these faults are also possible. Interbedded fine-grained nonmarine rocks are the likely seals; the lenticularity of these units is responsible for some uncertainty in trap viability.

Exploration status.—Approximately 19 wells with total depth greater than 1,500 ft (457 m) have been drilled in the United States part of this play since 1914. Of these, only seven wells had total depth greater than 5,000 ft (1,524 m), and 9,126 ft (2,782 m) is the deepest penetration. In Canada, approximately eight additional wells deeper than 5,000 ft (1,524 m) have been drilled, and maximum penetration is 14,789 ft (4,508 m). Most recently (between 1988 and 1991), three wells with total depths ranging from 4,422 to 9,126 ft (1,348 to 2,782 m) were drilled in the United States. Non-commercial gas shows were reported from several sandstone bodies and from coal beds in these wells. Future

Table 1. Conventional oil and gas plays in Washington.

[Summary and comparison of estimated probabilities for charge, reservoir, and trap; overall play probability; median number of petroleum accumulations larger than 1 MMBO (oil) or 6 BCF (gas); and size of the largest accumulation expected at a 0.05 probability]

Play name and number	Probability *				Median number of accumulations	Largest accumulation
	Charge	Reservoir	Trap	Overall		
Bellingham Basin Gas (401)	0.5	0.5	0.8	0.2	5	155 BCF
Southeastern Puget Lowland Gas (402)	0.9	1.0	0.75	0.68	10	125 BCF
Puget Lowland Deep Gas (403)	0.75	0.2	0.75	0.11	5	125 BCF
Tofino-Fuca Basin Gas (404)	1.0	0.5	0.4	0.2	7	30 BCF
Western Washington Melange (405)	1.0	1.0	0.5	0.5	10	13 MMBO
Southwest Washington Miocene Sandstone (406)	1.0	1.0	0.15	0.15	2	14 MMBO
Cowlitz-Spencer Gas (407)	1.0	1.0	1.0	1.0	10*	150 BCF
Northwestern Columbia Plateau Gas (501)	1.0	0.6	1.0	0.6	10	1,000 BCF

*The median number of accumulations shown is for the entire play area, which includes parts of southwest Washington and northwest Oregon. We estimate a median of four undiscovered gas accumulations for the Washington portion of the play (see text for discussion).

exploration in the Bellingham basin may concentrate on a potential coal-bed methane resource (see below) or on development of gas storage facilities similar to that currently operating in the Chehalis basin (Wurden and Ford, 1976). Pipelines bringing gas to the Pacific Northwest urban corridor from Alberta, Canada, extend through the Bellingham basin, so local infrastructure is highly favorable for development of a gas resource.

Evaluation of resource potential.—This play has been poorly to moderately explored. There is only minor information about rocks at depths greater than 5,000 ft (1,524 m). Based on existing knowledge, the best objectives for a conventional gas play are at depths of less than 5,000 ft (1,524 m), where source and reservoir rocks are each of marginal quality. For the recent U.S. Geological Survey 1995 National Petroleum Assessment (Gautier and others, 1995), Johnson and Tennyson (1995) assessed the probability of suitable charge, reservoir rock, and trap at 0.5, 0.5, and 0.8, respectively, yielding an overall play probability of 0.2 for a gas accumulation larger than 6 BCF (table 1). The median number of undiscovered gas accumulations larger than 6 BCF was estimated to be 5. The size of the largest accumulation expected at a 5 percent probability was estimated to be 155 BCF using the following simulation parameters and the methodology of Dolton and others (1987): Area of closure = 5,000 acres (20.2 km²); depth = 10,000 ft (3,048 m); reservoir thickness = 75 ft (23 m); effective porosity = 10 percent; trap fill = 0.8; recovery factor = 0.5; water saturation = 0.27. The mean undiscovered resource in the Bellingham Basin Gas play was estimated to be 30 BCF (table 2).

SOUTHEASTERN PUGET LOWLAND
GAS PLAY (402)

Introduction.—This hypothetical conventional gas play is located in the southeastern Puget Lowland and the western

flank of the Cascade Range of Washington (figs. 1, 3, 6). This region experienced transtensional deformation and rapid subsidence during the Eocene when coal-bearing rocks of the Puget Group and correlative strata were deposited (Johnson, 1985). From the Oligocene to the Holocene, transpressive deformation of basinal strata resulted in numerous faults and broad to tight folds (Gard, 1968; Vine, 1969; Stanley and others, 1996). This structural complexity has made precise correlation of coal-beds and other stratigraphic markers across the play area difficult.

The play extends north from the Morton area to the Tiger Mountain area and is about 18 to 30 mi (30 to 55 km) wide. The play is bounded to the east by either uplifts of pre-Tertiary rocks, or by a depositional contact where Eocene sedimentary rocks dip below a thick cover of Eocene and younger volcanic rocks. To the northwest, the play is bounded by the approximate facies contact between upper middle to upper Eocene nonmarine rocks (potential reservoir rocks within the play) and marine rocks (west of the play). To the west, the play boundary approximates the location of a poorly defined, north-trending boundary that separates a thicker, mainly nonmarine, more deformed, upper middle to upper Eocene sequence to the east from a thinner, mixed marine-nonmarine, less deformed, upper middle to upper Eocene sequence to the west.

The exploration premise is that gas has been generated from Eocene nonmarine carbonaceous shale and coal or marine mudstone and has migrated into reservoirs in Eocene fluvial and shallow marine sandstones of the Puget Group. Structural traps for reservoirs might include anticlines and fault blocks; interbedded and overlying fine-grained sedimentary rocks and (or) volcanic rocks would provide seals.

Reservoirs.—Middle to upper Eocene fluvial- and distributary-channel sandstone bodies of the undifferentiated Puget Group, the Tiger Mountain Formation, the Renton Formation, the Carbonado Formation, and the Spiketon Formation (fig. 2) are the target reservoirs for this gas play. These

Table 2. Conventional oil and gas in Washington.

[Estimates of undiscovered technically recoverable resources by play (Johnson and Tennyson, 1995; Tennyson, 1995). Fractile values (F₉₅, F₅) are not additive. F₉₅ represents a 19 in 20 chance and F₅ represents a 1 in 20 chance of the occurrence of at least the amount tabulated]

Play name and number	Crude oil (million barrels)			Gas (billion cubic feet)		
	F ₉₅	F ₅	Mean	F ₉₅	F ₅	Mean
Bellingham Basin Gas (401)	0.00	0.00	0.00	0.00	229.20	30.00
Southeastern Puget Lowland Gas (402)	0.00	0.00	0.00	0.00	615.20	163.20
Puget Lowland Deep Gas (403)	0.00	0.00	0.00	0.00	139.00	26.80
Tofino-Fuca Basin Gas (404)	0.00	0.00	0.00	0.00	108.60	15.00
Western Washington Melange (405)	0.00	89.20	18.20	0.00	0.00	0.00
Southwest Washington Miocene Sandstone (406)	0.00	7.60	1.10	0.00	0.00	0.00
Cowlitz-Spencer Gas (407)	0.00	0.00	0.00			115.89*
Northwestern Columbia Plateau Gas (501)	0.00	0.00	0.00	0.00	1,119.70	235.10
TOTAL			19.30			585.99

*The Cowlitz-Spencer Gas play (407) includes parts of Oregon and Washington; however, only the estimated resource for the Washington portion of the play is shown on this table. The resource was allocated between the States based on our evaluation of the geologic framework and petroleum geology.

sandstone bodies range in thickness from 10 ft (3 m) to more than 200 ft (61 m) and are bounded by fine-grained flood-plain deposits (Vine, 1969; Johnson and Stanley, 1995). Sandstone reservoirs might be present at depths of as much as 10,000 ft (3,048 m).

Sandstone is typically arkosic (e.g., Buckovic, 1978; Frizzell, 1978; Johnson and Stanley, 1995). Petrographic and meager porosity-permeability data suggest that sandstones are “tight” in the eastern part of the play where rocks have been subjected to higher geothermal gradients; loss of porosity reflects compaction and alteration of lithic fragments and feldspar. Porosity and permeability increase in the western part of the play. Near Black Diamond, porosities from two cores (depth range of 1,840 to 6,000 ft (561 to 1,829 m)) range from 6 to 37 percent and permeability ranges from 1 mD to 2 darcies (unpub. industry data).

Exploration drilling has indicated locally high reservoir pressures (possibly artesian); the “Flaming Geyser” well (total depth of 1,411 ft; 430 m), drilled as a coal test in 1911 in the Green River district, was abandoned because of gas (flares as high as 30 ft; 9.1 m) and water flows. This well continues to flow traces of gas.

Source rocks.—There are two possible source rocks for this hypothetical gas play. Organic matter for both potential source rocks is mostly type III and gas prone, although Lingley and von der Dick (1991) also report type-II organic matter from these rocks: Source 1—Upper middle to upper Eocene carbonaceous shale and coal of the undifferentiated Puget Group, and the Tiger Mountain, Renton, Carbonado, and Spiketon Formations (fig. 2). Coal desorbtion data indicate that coals have generated significant gas (Walsh and Lingley, 1991). Surface outcrops and samples from shallow wells (< 2,000 ft (610 m)) have mean vitrinite reflectance ranging from about 0.35 to 2.0 percent (Walsh and Lingley, 1991; Johnson and Stanley, 1995, unpub. U.S. Geological Survey data). Thermal maturity generally increases to the

east and in close proximity to intrusives (Walsh and Lingley, 1991; Esposito and Whitney, 1995; Johnson and Stanley, 1995). Source 2—Lower to middle Eocene marine mudstones. These rocks are exposed only on Tiger Mountain, east of Seattle, where they are assigned to the Raging River Formation (Vine, 1969; Johnson and O’Connor, 1994) , but they are inferred to underlie a significant portion of the southeastern Puget Lowland (Stanley and others, 1992, 1994; Johnson and Stanley, 1995). The source-rock properties of the Raging River Formation are described above.

Timing and migration of hydrocarbons.—As with the Puget Lowland Deep Gas play (403; see below), maximum burial occurred in the late Eocene to Oligocene, prior to Oligocene and Neogene folding and associated uplift. Much of this folding and uplift was controlled by movement on local faults or fault networks and is not associated with a regional contractional event (Johnson and others, 1994; Stanley and others, 1996). Regional heat flow became elevated in the Oligocene and Miocene with the onset of Cascade Range volcanism in the Oligocene and early Miocene. Thus, maximum heating and thermal maturation may locally postdate maximum burial. Because of ongoing deformation, structural traps in the play area have probably formed before, during, and after peak hydrocarbon generation.

Walsh and Lingley (1991) used a variety of maturation data to show that the central Puget trough (west part of play) has had unusually low geothermal gradients since the middle Eocene. They note that gradients increase eastward to the Cascade crest, defining a fairway of conditions favoring peak gas generation at moderate depths that trends north along the western foothills of the Cascade Range.

Traps.—Anticlines and fault blocks such as those that occur in the Morton or Carbon River anticlines or near Black Diamond (Gard, 1968; Vine, 1969; Johnson and Stanley, 1995; Stanley and others, 1996) form the most viable hydrocarbon traps. Interbedded fine-grained

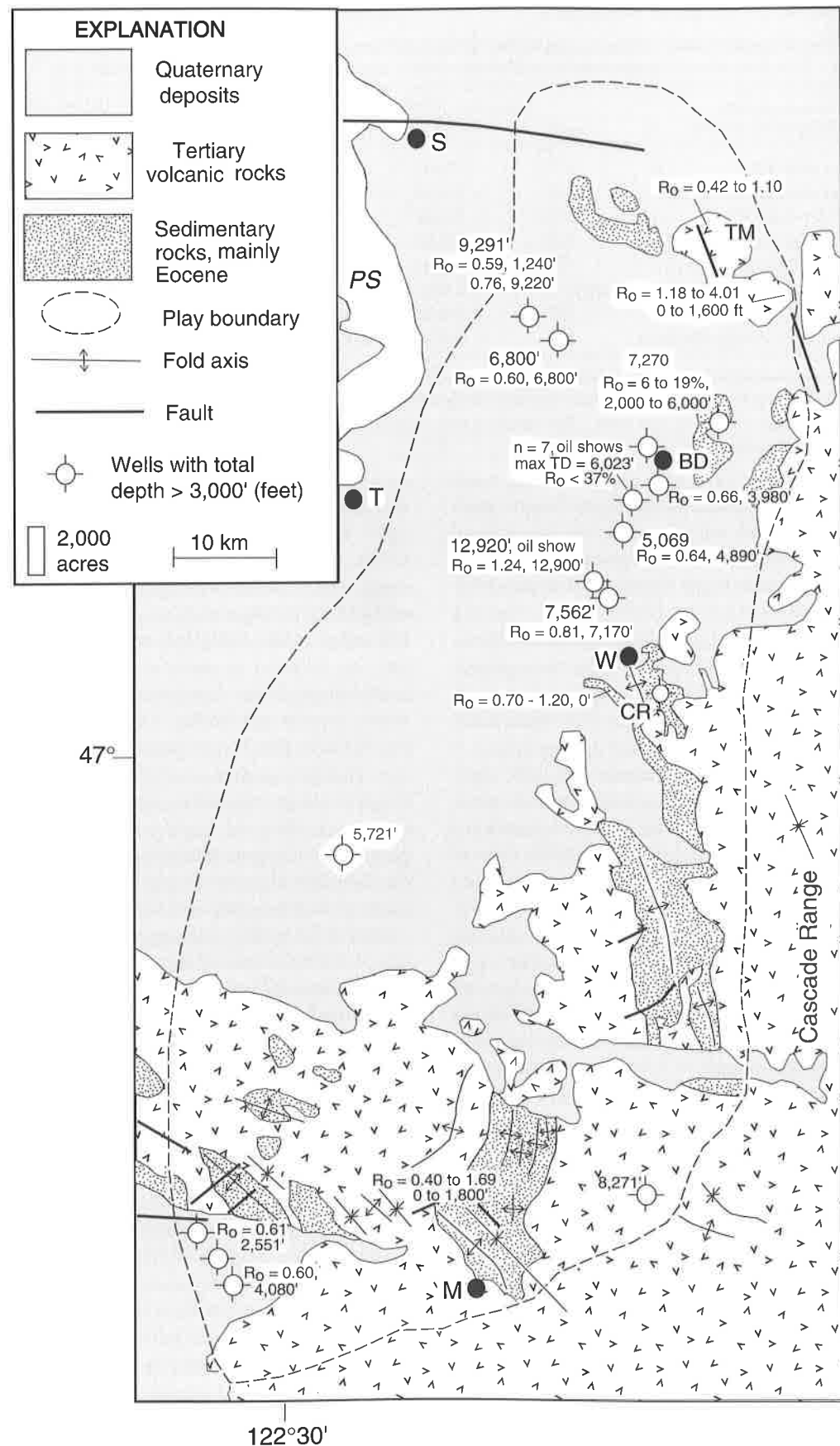


Figure 6 (facing page). Schematic map showing Southeastern Puget Lowland Gas play (402). Petroleum wells are listed in McFarland (1983) or in addendum to McFarland available through the Washington Division of Geology and Earth Resources. Thermal maturity data (R_o = mean vitrinite reflectance) is from Walsh and Lingley (1991), Johnson and O'Connor (1994), Johnson and Stanley (1995), or the data are previously unpublished; values are from surface samples unless footage from adjacent petroleum well is listed. BD, Black Diamond; CR, Carbon River anticline; M, Morton; PS, Puget Sound; S, Seattle; T, Tacoma; TM, Tiger Mountain; W, Wilkeson. Geology simplified after Walsh and others (1987) and Washington Public Power Supply (1991).

rocks (fluvial overbank deposits) and Oligocene and younger volcanic rocks provide possible seals. Traps might be present at depths ranging from the near surface to 10,000 ft (3,050 m). The area is structurally complex and includes many faults and folds that may have been active from the Neogene to the Quaternary and may have compromised the integrity of traps and seals.

Exploration status.—Approximately 30 wells with total depths greater than 3,000 ft (914 m) have been drilled in the play area, including one well with a total depth of 12,920 ft (3,938 m) drilled in 1963, and 10 with total depths between 5,000 and 10,000 ft (1,524 and 3,048 m) (McFarland, 1982). In the early 1980's, AMOCO drilled 11 stratigraphic test wells in the area of this play, with a maximum total depth of 2,780 ft (847 m). Three other wells with depths ranging from 4,872 ft (1,485 m) to 8,271 ft (2,521 m) were drilled between 1983 and 1989 (addendum to McFarland, 1983).

Evaluation of resource potential.—The Southeastern Puget Lowland Gas play (402) has been poorly explored (fig. 6). In the most favorable exploration scenario, gas generated from source rocks in the eastern, more thermally mature part of this play, has migrated westward to the best reservoir rocks in the western part of the play. The history of Neogene tectonism and uplift may limit both longer distance migration and the integrity of traps. The structural complexity along with highly variable surface geology makes acquisition and interpretation of seismic reflection profiles difficult. If traps for gas are present, these traps are probably small (6–20 BCF).

For the recent U.S. Geological Survey 1995 National Petroleum Assessment (Gautier and others, 1995), Johnson and Tennyson (1995) assessed the probability of suitable charge, reservoir rock, and trap at 0.9, 1.0, and 0.75, respectively, yielding an overall probability of 0.68 for a gas accumulation larger than 6 BCF (table 1). The median number of undiscovered gas accumulations larger than 6 BCF was estimated to be 10. The size of the largest accumulation expected at a 5 percent probability was estimated to be 125 BCF using the following simulation parameters and the methodology of Dolton and others (1987): Area of closure =

2,000 acres (8.1 km²); depth = 10,000 ft (3,048 m); reservoir thickness = 75 ft (23 m); effective porosity = 10 percent; trap fill = 0.8; recovery factor = 0.5; water saturation = 0.27. The mean undiscovered resource in the Southeastern Puget Lowland gas play was estimated to be 163.2 BCF (table 2).

PUGET LOWLAND DEEP GAS PLAY (403)

Introduction.—This hypothetical conventional gas play is located in the southeastern Puget Lowland and the western flank of the Cascade Range of Washington (figs. 1, 3, 7). The play extends north from near the town of Morton to northern Whidbey Island and is about 25 to 30 mi (40 to 50 km) wide. A progradational sequence of Eocene deep marine to nonmarine sedimentary rocks, including the Raging River Formation, the sandstone of Scow Bay, and the lower Puget Group (fig. 2), forms the potential petroleum system of this play (Ise, 1985). The play is bounded to the east and north by uplifts of pre-Tertiary rocks, or by a depositional contact where Eocene sedimentary rocks dip below a thick cover of Eocene and younger volcanic rocks (Washington Public Power Supply, 1981; Walsh and others, 1987; Whetten and others, 1988). Structural uplifts cored by Eocene marine basalt of the Crescent Formation bound the play to the northwest. The southwest boundary of the play lies a few kilometers west of an early to early middle Eocene facies change where thick sequences of marine strata to the east are inferred to interfinger with marine basalt to the west (Johnson and Stanley, 1995). Along the axis of the Puget Lowland, the Eocene section is overlain by heterogeneous Oligocene to Quaternary strata of variable thickness. Quaternary depocenters include the Seattle, Everett, and Tacoma basins. The play area experienced transtensional deformation and rapid subsidence during the Eocene (Johnson, 1985). From the Oligocene to the present, contractional and transpressive deformation of basinal strata resulted in numerous faults and broad to tight folds (Gard, 1968; Vine, 1969; Johnson and others, 1994; Stanley and others, 1996).

The exploration premise of this play is that gas has been generated from deeply buried Eocene marine mudstone and has migrated into overlying interbedded shelf or deep-water sandstone reservoirs. Structural traps for reservoirs might include anticlines and fault blocks, and interbedded fine-grained rocks and (or) volcanic rocks would provide seals.

Reservoirs.—Potential reservoirs for the Puget Lowland Deep Gas play (403) include lower to middle Eocene marine sandstone of the Raging River Formation (Johnson and O'Connor, 1994) and unnamed deeply buried correlative units. Sandstone in the Raging River Formation is lithic rich, and samples from outcrops and one core have minimal porosity or permeability (Johnson and O'Connor, 1994). Outcrop and subsurface data are

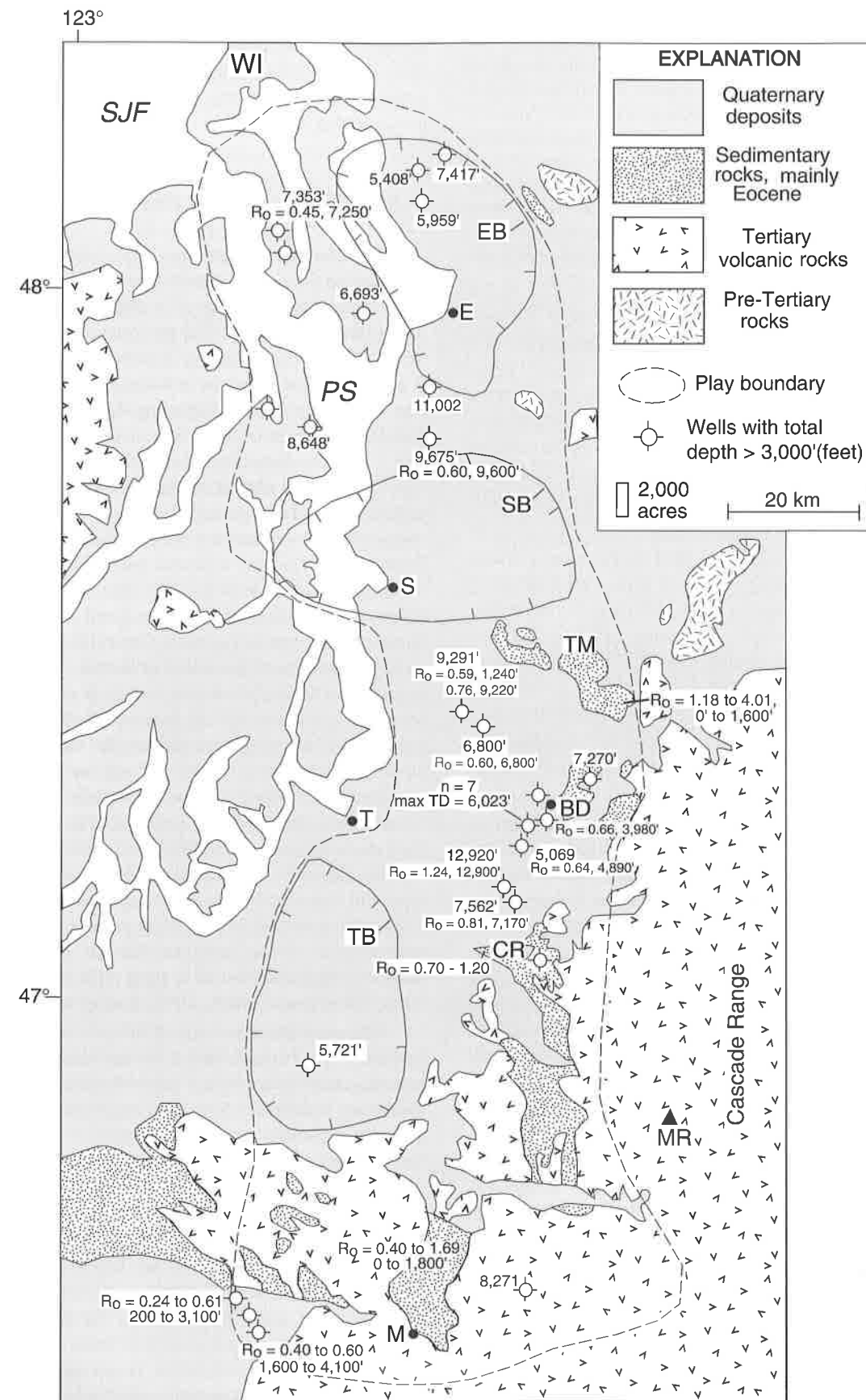


Figure 7 (facing page). Schematic map showing Puget Lowland Deep Gas play (403). Petroleum wells are listed in McFarland (1983) or in addendum to McFarland available through the Washington Division of Geology and Earth Resources. Thermal maturity data (R_o = mean vitrinite reflectance) is from Walsh and Lingley (1991), Johnson and O'Connor (1994), Johnson and Stanley (1995), or was previously unpublished; values are from surface samples unless footage from adjacent petroleum well is listed. BD, Black Diamond; CR, Carbon River area; E, Everett; EB, Everett basin; M, Morton; MR, Mount Rainier; PS, Puget Sound; S, Seattle; SB, Seattle basin; SJF, Strait of Juan de Fuca; T, Tacoma; TB, Tacoma basin; TM, Tiger Mountain; WI, Whidbey Island. Geology simplified after Walsh and others (1987) and Washington Public Power Supply (1991).

insufficient to evaluate sandstone thickness and geometry. There are no available data on correlative deeply buried units in the play area; however, based on regional paleogeographic patterns (e.g., Buckovic, 1978; Johnson, 1985; Johnson and Stanley, 1995), sandstone of both arkosic and lithic composition should be present in these units.

Source rocks.—Source rocks are inferred to be lower to middle Eocene marine mudstones (Johnson and O'Connor, 1994). These rocks are exposed only on Tiger Mountain, east of Seattle, where they are assigned to the Raging River Formation, but they are inferred to underlie a significant portion of the Puget Lowland (Johnson and Stanley, 1995). At Tiger Mountain, mean vitrinite reflectance of surface samples varies from 1.18 to 4.01 percent, and is 1.96 percent at 1,633 ft (498 m) in one well (Johnson and O'Connor, 1994). T_{max} (the temperature at which maximum yield of hydrocarbons occurs during Rock-Eval pyrolysis of organic matter) ranges from about 509°C to 542°C in samples from outcrop and the shallow subsurface—too high for reliable evaluation of petroleum source rocks (Peters, 1986). Total organic carbon in these samples is as high as 0.8 to 1.1 percent. This remnant organic matter is an indication that rocks may have once been more organic rich and capable of generating hydrocarbons (Daly and Edman, 1987).

Timing and migration of hydrocarbons.—Maximum burial in most of the play occurred during the late Eocene to early Oligocene, prior to Oligocene and Miocene contractional and transpressive deformation, folding, and associated uplift. Regional heat flow became elevated in the Oligocene and Miocene with the onset of Cascades volcanism in the Oligocene and early Miocene. Thus, maximum heating and thermal maturation may postdate maximum burial. Structural traps in the play area probably formed during and slightly later than peak hydrocarbon generation (Walsh and Lingley, 1991).

Strata in the deeper parts of the Seattle and Everett basins (fig. 7) are presently at maximum burial (Johnson and others, 1994, 1996) and probable maximum thermal

maturation. Structural traps within and on the margins of these basins thus predate peak hydrocarbon generation from basinal strata.

Traps and seals.—Anticlines and fault blocks form the most viable hydrocarbon traps. Anticlines include large structures such as the Kingston arch on the northern flank of the Seattle basin (Johnson and others, 1994) and complex, smaller scale structures such as those in the Morton, Carbon River, and Black Diamond areas in the western Cascade Range foothills (Gard, 1968; Vine, 1969; Johnson and Stanley, 1995; Stanley and others, 1996). Interbedded and overlying fine-grained Eocene rocks (marine and nonmarine) and Oligocene and younger volcanic rocks provide possible seals. Traps might be present at depths ranging from 10,000 to 25,000 ft (3,048 to 7,620 m). The area includes many faults and folds that have been active through the Neogene and Quaternary and may have compromised the integrity of reservoirs and traps.

Exploration status.—Only two wells have penetrated the top of the prospective section (10,000 ft; 3,048 m) in this play. Approximately 40 wells with total depths greater than 3,000 ft (914 m) have been drilled in the play area, and 17 have total depths between 5,000 and 10,000 ft (1,524 and 3,048 m) (McFarland, 1983). In the last 10 years, activity in the play area has emphasized a possible shallow coal-bed methane resource (Choate and others, 1984; Pappajohn and Mitchell, 1991; Walsh and Lingley, 1991; Johnson and Tennyson, 1995). The U.S. Department of Energy recently supported acquisition of a large seismic database for the purpose of delineating a large conductive anomaly in the Cascade foothills that probably represents the Eocene marine rocks that are the inferred source and reservoir for this play (Stanley and others, 1992; Krehbiel, 1993; Zihlman, 1993; Johnson and Stanley, 1995).

Evaluation of resource potential.—The viability of the Puget Lowland Deep Gas play (403) is dependent on the hypothesis that (1) marine source rocks underlie a large part of the Puget Lowland, (2) an adequate thickness of reservoir rocks may be present, (3) potential reservoir sandstone has a favorable diagenetic history, (4) there has been a favorable migration history, and (5) traps and seals have retained their viability in a structurally complex setting. Given the uncertainties associated with each factor, this play is considered high risk. For the recent U.S. Geological Survey 1995 National Petroleum Assessment (Gautier and others, 1995), Johnson and Tennyson (1995) assessed the probability of suitable charge, reservoir, and trap at 0.75, 0.2, and 0.75, respectively, yielding an overall play probability of 0.11 for a gas accumulation larger than 6 BCF (table 1). The median number of undiscovered gas accumulations larger than 6 BCF was estimated to be 5. The size of the largest accumulation expected at a 5 percent probability was estimated to be 125 BCF using the following simulation parameters and the methodology of Dolton and others (1987): Area of closure =

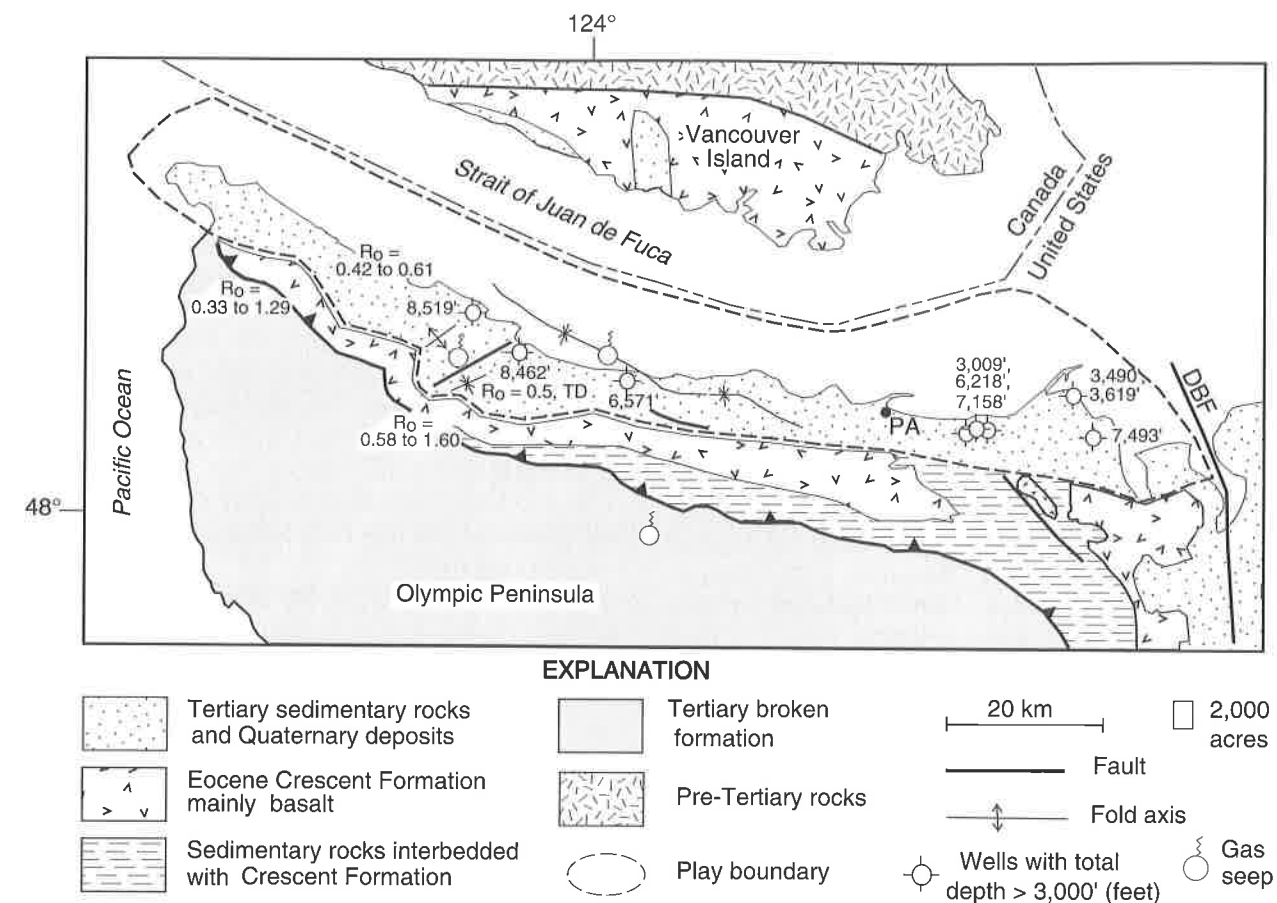


Figure 8. Schematic map showing Tofino-Fuca Basin Gas play (404). Petroleum wells are listed in McFarland (1983) or in addendum to McFarland available through the Washington Division of Geology and Earth Resources. Geology (including selectively displayed faults and folds) is based on Tabor and Cady (1978). Thermal maturity data (R_o = mean vitrinite reflectance) and location of gas seeps is from Snaveley and Kvenvolden (1989) and Niem and Snaveley (1991); values for vitrinite reflectance are from surface samples unless footage from adjacent petroleum well is listed. DBF, Discovery Bay fault; PA, Port Angeles.

2,000 acres (8.1 km²); depth = 10,000 ft (3,048 m); reservoir thickness = 75 ft (23 m); effective porosity = 15 percent; trap fill = 0.8; recovery factor = 0.5; water saturation = 0.27. The mean undiscovered resource in the Puget Lowland Deep Gas play was estimated to be 26.8 BCF (table 2).

TOFINO-FUCA BASIN GAS PLAY (404)

Introduction.—This hypothetical conventional gas play is located in the Tofino-Fuca basin on the northern Olympic Peninsula of Washington (figs. 1, 3, 8). This basin occupies a modern topographic lowland that extends from southern Vancouver Island to the Olympic Mountains and includes the Strait of Juan de Fuca. Initial subsidence in the basin was of middle Eocene age and probably driven by thermal subsidence of the volcanic Crescent Formation basement. Johnson and others (1996) inferred that late Eocene and younger subsidence was forced by contractional deformation associated with northward tectonic transport of the Washington Coast Range province.

The Tofino-Fuca Basin Gas play (404) is bounded on the south by basement outcrops of the volcanic Crescent Formation, to the north by the international boundary with Canada in the Strait of Juan de Fuca, and to the west by the 3-mi limit of State waters in the Pacific Ocean. To the east, the play is bounded by the north-trending Discovery Bay fault zone, which disrupts and partially truncates the stratigraphic sequence.

The exploration premise for the Tofino-Fuca Basin Gas play (404) is that gas has been generated from either Eocene strata buried in the deepest part of the basin or from Eocene melange and (or) broken formation in a structural plate underlying the basin. Once generated, this gas has migrated either up-dip from deep basinal sources or up basement fault zones into Eocene or Oligocene turbidite sandstone reservoirs. Traps are most likely stratigraphic in character (for example, buried pinch-outs of turbidite sandstone beds), but small fault traps are also possible.

Reservoirs.—Upper middle Eocene to Oligocene turbidite sandstone beds of the Twin River Group, including the

Hoko River, Makah, and Pysht Formations, are the target reservoirs (Snaveley and others, 1980; Niem and Snaveley, 1991). Individual sandstone beds range up to about 40 ft (12 m) in thickness and form composite units that are as thick as 400 ft (122 m). Many sandstone beds and composite units are bounded vertically and laterally by marine mudstones. The proportion and thickness of sandstone beds within the Twin River Group decreases to the east within the play area. Sandstone is lithic-arkosic to quartzo-feldspathic in composition. Meager data suggest that porosity and permeability in the best potential reservoir rocks may be as high as 20.4 to 24.6 percent and 2 to 657 mD, respectively (Niem and Snaveley, 1991). Reservoir rocks are inferred to dip northward into a basin-axis syncline, where they are buried as deeply as 17,000 ft (5,182 m) (Snaveley, 1983; Niem and Snaveley, 1991).

Source rocks.—There are two possible source rocks for this play: Source 1—Eocene marine mudstone located down-dip in the deepest part of the basin is the first possible source. Total organic carbon in this interval (from surface exposures and one well) ranges from 0.3 and 1.2 percent (Snaveley and others, 1980; Niem and Snaveley, 1991). The composition of organic matter plots in a nondiagnostic area on Van Krevelen diagrams near the convergence of type-III and type-II fields (Niem and Snaveley, 1991). Sparse vitrinite reflectance data for surface and well samples (as deep as 8,400 ft (2560 m)) ranges from about 0.4 to 0.5 percent. However these rocks are buried as deeply as 25,000 ft (7,620 m) to the north in the deepest part of the basin (Snaveley, 1983; Niem and Snaveley, 1991) where higher levels of thermal maturity are expected. Source 2—Marine mudstone in Eocene melange and (or) broken formations that occur in a structural plate beneath the Tofino-Fuca basin (Snaveley and Kvenvolden, 1989) is the second possible petroleum source rock for this play. These rocks crop out south of the Tofino-Fuca Basin Gas play in the Olympic Mountains (fig. 8). Total organic carbon in these rocks is typically 0.4 to 0.9 percent. Organic matter is mostly type III and gas prone. Vitrinite reflectance of surface samples typically ranges from about 0.35 to 1.6 percent (Palmer and Lingley, 1989; Snaveley and Kvenvolden, 1989).

There are at least two seeps of thermogenic gas in the area of the play (fig. 8), indicating that source rocks have reached maturity and generated hydrocarbons. One seep was crudely gauged at a flow rate of 20 MCFGPD of methane (Lingley, 1986).

Timing and migration of hydrocarbons.—Folding in the Tofino-Fuca basin and uplift of the Olympic Mountains began in the middle Miocene (Brown and others, 1960; Tabor and Cady, 1978; Brandon and Calderwood, 1990; Snaveley and others, 1993). Peak migration of gas probably occurred immediately before this deformation, during maximum burial of both the coherent strata in the Tofino-Fuca basin and the melange and (or) broken formation in the structurally lower thrust plate.

Traps.—Possible stratigraphic traps include buried pinch-outs of turbidite channel and lobe sandstone beds. However, many of these potential reservoir bodies have been breached by erosion on the south flank of the basin in the play area. Obvious locations of structural traps are few and small and might occur along faults. Marine mudstone interbedded with the turbidite sandstone forms the potential seals.

Exploration status.—Nine exploration wells with total depths greater than 2,740 ft (835 m) were drilled in the area of the Tofino-Fuca Basin Gas play (404) between 1948 and 1986. The two most recent wells include the 1986 Twin River Oil and Gas State No. 1-30 well (total depth = 6,571 ft (2,003 m)) and the 1982 Fairview Oil and Gas No. 1 well (total depth = 7,158 ft (2,182 m)) (McFarland, 1983; Lingley, 1986). Neither well encountered significant hydrocarbon shows, and there is no known exploration in this play at the present.

Evaluation of resource potential.—The Tofino-Fuca Basin Gas play (404) has been poorly explored. There is only minor available geological and geophysical information about rocks at depths greater than 5,000 ft (1,524 m). The presence of thermogenic gas seeps clearly indicates a viable source rock for the play. The presence of suitable reservoirs and traps is less certain, downgrading the overall play potential. For the recent U.S. Geological Survey 1995 National Petroleum Assessment (Gautier and others, 1995), Johnson and Tennyson (1995) assessed the probability of suitable charge, reservoir rock, and trap at 1.0, 0.5, and 0.4, respectively, yielding an overall play probability of 0.2 for a gas accumulation larger than 6 BCF (table 1). The median number of undiscovered gas accumulations larger than 6 BCF was estimated to be 7. The size of the largest accumulation expected at a 5 percent probability was estimated to be 30 BCF using the following simulation parameters and the methodology of Dolton and others (1987): Area of closure = 700 acres (2.8 km²); depth = 10,000 ft (3,048 m); reservoir thickness = 40 ft (12 m); effective porosity = 15 percent; trap fill = 0.8; recovery factor = 0.7; water saturation = 0.27. The mean undiscovered resource in the Tofino-Fuca Basin Gas play was estimated to be 15 BCF (table 2).

WESTERN WASHINGTON MELANGE PLAY (405)

Introduction.—This conventional oil play is located along most of the Pacific Coast of Washington (figs. 1, 8, 9). The entire petroleum system is inferred to occur within the Eocene to upper middle Miocene stratified sedimentary rock and melange or broken formation of the Ozette terrane (Snaveley and others, 1993) and the Hoh rock assemblage of Rau (1973). Strata within these units were mostly deposited in bathyal marine environments on Pacific basin plates, then accreted to the leading edge of the North American plate along a subduction zone. The exploration premise is that

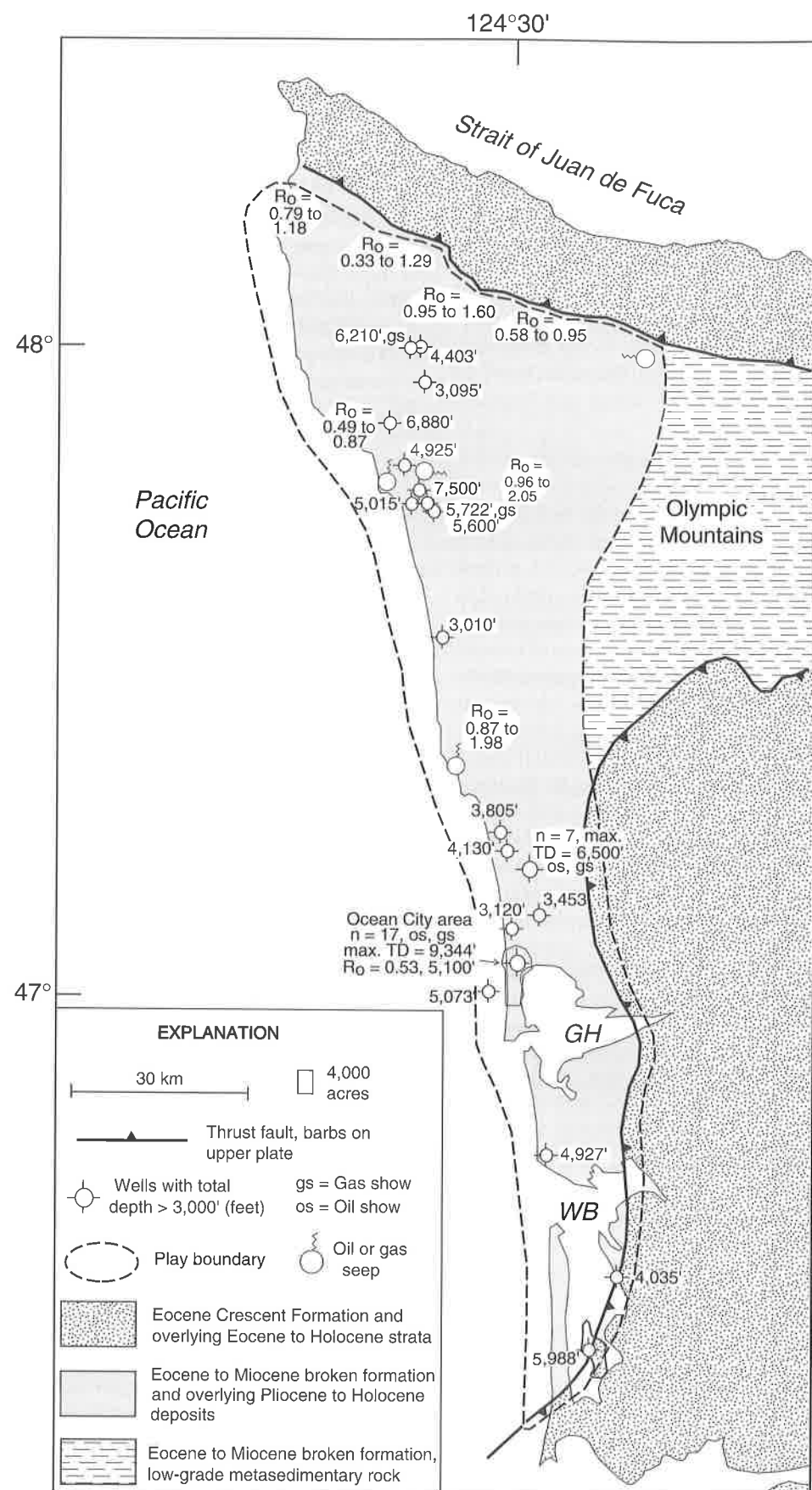


Figure 9 (facing page). Schematic map showing Western Washington Melange play (405). Petroleum wells are listed in McFarland (1983) or in addendum to McFarland available through the Washington Division of Geology and Earth Resources. Geology is based on Tabor and Cady (1978) and Walsh and others (1987). Thermal maturity data (R_o = mean vitrinite reflectance) and locations of seeps are from Snively and Kvenvolden (1989) and Palmer and Lingley (1989); values for vitrinite reflectance are from surface samples unless footage from adjacent petroleum well are listed. GH, Grays Harbor. WB, Willapa Bay.

petroleum generated from organic-rich mudstones in the melange and (or) broken formation has migrated into sandstone reservoirs in coherent structural blocks within the melange.

This play is bounded to the north and southeast by a system of thrust faults that juxtaposes lower-plate melange and broken formation with upper-plate Eocene marine volcanic rocks of the Crescent Formation and overlying Tertiary strata. In the Olympic Mountains, the eastern limit of the play approximates the location where induration and low-grade metamorphism of the Ozette and Hoh units become pervasive. To the west, the play extends to the 3-mi limit of State waters.

Reservoirs.—Deep-marine channel sandstone beds within coherent structural blocks in the Ozette terrane and the Hoh rock assemblage are the inferred reservoir rocks. Based on log analysis of wells from the Ocean City area, Palmer and Lingley (1989) suggest that sandstone units range from 10 to 100 ft (3 to 30 m) in thickness, with a mean of about 34 ft (10 m). Composite sandstone units in outcrop are as thick as 140 ft (42 m) (Lingley, 1995). Thicker sandstone units, mainly distributary channel deposits of limited areal extent, probably include fine-grained interbeds or drapes and are heterogeneous. Most sandstone units have porosities less than 25 percent and permeabilities less than 100 mD (Palmer and Lingley, 1989).

Source rocks.—Marine mudstone in the Eocene to upper middle Miocene Ozette terrane and Hoh rock assemblage is inferred to be a widely distributed petroleum source rock. The distribution of source rocks within these units is impossible to determine because of internal structural complexity; however, melange-like rocks extend down to the top of the down-going Juan de Fuca plate (about 50,000–60,000 ft; 15,000 to 18,000 m), and abundant source rock is expected. Surface and well samples have relatively low total organic carbon (typically 0.5 to 1.0 percent) and type-III organic matter (Snively and Kvenvolden, 1989). Although gas is the expected hydrocarbon type, drilling records report numerous oil shows. These shows and oil seeps are present along an 84-mi-long (135 km), north-trending fairway within the play. Approximately 12,000 barrels of oil were produced from the Hoh rock assemblage in one well in the Ocean City area (fig. 9) from 1957 to 1961 (McFarland, 1983; Palmer and Lingley, 1989). Thus, oil-prone source

rocks must be present at depth. Both oil and gas seeps occur within the play area (fig. 9). Thermal maturity in possible source rocks exposed at the surface or penetrated in wells (fig. 9) varies significantly, probably in response to internal structural disruption. In the Ocean City area, rocks at depths of as much as 6,000 ft (1,829 m) have typical mean vitrinite reflectance of 0.5 percent. However, in outcrops about 15.5 mi (25 km) to the north, mean vitrinite reflectance in correlative rocks is generally between 1.0 and 1.5 percent. Surface vitrinite reflectance in the northern part of the play varies from 0.33 to 2.05 percent (Snively and Kvenvolden, 1989) (fig. 9).

Timing and migration of hydrocarbons.—Migration in this complex setting has probably occurred continuously from the Oligocene to the present, as marine sedimentary rocks of Eocene and younger age were progressively underplated beneath the continental margin. Upward and westward migration of hydrocarbons along faults within the Ozette and Hoh units seems likely (Snively and Kvenvolden, 1989; Palmer and Lingley, 1989).

Traps.—There is almost certainly a variety of trap types within the structurally complex Ozette and Hoh units, associated with fault blocks, anticlines, mudstone diapirs, and stratigraphic pinch-outs or unconformities. Given the structural complexity of these units, individual traps are probably small (less than 1,000 acres (4 km²). Fine-grained rocks within the Ozette and Hoh units provide the seal. The expected uniformity in depositional and structural style across the play area suggests that traps are equally likely in any part of the play. Similarly, the traps might occur at depths ranging from about 2,000 ft to about 23,000 ft (610 to 7,010 m), the depth at which gas should disappear given geothermal gradients of about 1.5°F/100 ft (26°C/km).

Exploration status.—There is no known ongoing exploration in this play. About 80 exploration wells have been drilled in the play area since the early 1900's, with 43 having total depths greater than 3,000 ft. This exploration occurred in several discrete phases described in Palmer and Lingley (1989). The last major exploration push in this play ended in the late 1960's following drilling by Shell and Pan American on the adjacent continental shelf.

Evaluation of resource potential.—The Western Washington Melange play (405) has limited potential given current technology. Reservoir quality and the integrity of traps are considered the major limiting factors. Because of the complex structural style and poor outcrop quality, exploration is extremely difficult. Moreover, the small anticipated size of traps and reservoirs may discourage explorationists.

For the recent U.S. Geological Survey 1995 National Petroleum Assessment (Gautier and others, 1995), Johnson and Tennyson (1995) assessed the probability of suitable charge, reservoir rock, and trap for an oil accumulation at 1.0, 1.0, and 0.5, respectively, yielding an overall play probability of 0.5 for an accumulation larger than 1 MMBO (table 1). The median number of undiscovered oil

accumulations larger than 1 MMBO was estimated to be 10. The size of the largest accumulation expected at a 5 percent probability was estimated to be 13 MMBO using the following simulation parameters and the methodology of Dolton and others (1987): Area of closure = 1,000 acres (4 km²); reservoir thickness = 75 ft (23 m); effective porosity = 15 percent; trap fill = 0.8; recovery factor = 0.24; water saturation = 0.27. The mean undiscovered oil resource was estimated to be 18.2 MMB (table 2).

Johnson and Tennyson (1995) assessed the probability of suitable charge, reservoir rock, and trap for a gas accumulation at 1.0, 1.0, and 0.1, respectively, yielding an overall play probability of 0.1 for a gas deposit larger than 6 BCF. Given this low play probability, the mean undiscovered gas resource was not estimated.

SOUTHWEST WASHINGTON MIOCENE SANDSTONE PLAY (406)

Introduction.—This hypothetical conventional oil play is located in the parts of the Grays Harbor basin area of southwest Washington (figs. 1, 3, 10) where Miocene shallow-marine sedimentary rocks have been deposited and preserved. The play has an irregular shape and is bounded by the upwarped margins of the Grays Harbor basin to the north, south, and east. To the west, the play extends to the 3-mi limit of State waters.

Eocene and Oligocene subsidence of the Grays Harbor basin was probably generated by thermal subsidence of the underlying volcanic basement, the lower to middle Eocene Crescent Formation (Johnson and Yount, 1992). Neogene subsidence was apparently forced by a variety of tectonic processes involving contractional shortening, strike-slip faulting, and rotation (Wells and Coe, 1985). The play area includes a major north-trending, east-dipping thrust fault (fig. 10) that represents a middle Tertiary plate boundary. West of this boundary, Miocene shallow-marine rocks of the Montesano Formation were deposited on the lower structural plate consisting of Eocene to Miocene stratified rock and melange of the Ozette terrane (Snively and others, 1993) and Hoh rock assemblage (Rau, 1973). East of this boundary, the Astoria and Montesano Formations were deposited on an upper structural plate consisting of Crescent Formation basement overlain by a stratigraphically coherent, generally shoaling upward, sequence of Eocene to Miocene sedimentary rocks.

The exploration premise of this hypothetical play is that oil and gas generated from organic-rich mudstone in Eocene to upper middle Miocene melange and broken formation of the lower structural plate described above has migrated upward into porous and permeable shallow-marine sandstone of the Miocene Montesano and (or) Astoria Formations. Structural traps for reservoirs could include small

anticlines and fault blocks. Where present, overlying fine-grained rocks might provide viable seals.

Reservoirs.—Miocene shallow marine and deltaic sandstone of the Astoria and lower Montesano Formations in the eastern part of play, and the Montesano Formation in the western part of play, are the target reservoirs. In the Ocean City area (fig. 10) in the west-central part of the play, Palmer and Lingley (1989) describe a remarkable 600 ft (183 m) of sandstone in the Montesano Formation that averages 28 percent porosity and 1 darcy of permeability. In the eastern part of the play, several 100-ft-thick (30 m) sandstone beds occur in both the Astoria and Montesano Formations (Bigelow, 1987). The proportion of sandstone in both the Montesano and Astoria Formations generally decreases to the west. Sandstone units are typically bounded by marine mudstone. Target reservoir sandstone units occur at depths of about 1,000 to 3,200 ft (305 to 975 m).

Montesano Formation sandstone is lithic arenite (Bigelow, 1987) and typically has porosities greater than 20 percent and permeabilities ranging from 2 to 2,000 mD (Palmer and Lingley, 1989). There are no available porosity and permeability data for the Astoria Formation in this play, but Astoria sandstone outcrops are friable, and values similar to those of the Montesano Formation are inferred.

Source rocks.—Eocene to upper middle Miocene marine mudstone of the Ozette terrane and Hoh rock assemblage is the inferred hydrocarbon source rock. The thickness of source-rock units is impossible to determine because of internal structural complexity within these units. However, melange-like rocks are inferred to extend down to the top of the down-going Juan de Fuca plate, about 50,000 to 60,000 ft (15,000 to 18,000 m) deep. Surface and well samples have relatively low total organic carbon (typically 0.5 to 1.0 percent) and generally type-III organic matter (Snively and Kvenvolden, 1989). Although gas is the expected hydrocarbon type, drilling records report numerous oil shows, and approximately 12,000 barrels of oil were produced from the Hoh rock assemblage in one well between 1957 and 1961 (McFarland, 1983; Palmer and Lingley, 1989). Thus, oil-prone source rocks are expected at depth. Thermal maturity in possible source rocks varies significantly, probably in response to structural disruption. In the Ocean City area, rocks at depths of as much as 6,000 ft (1,830 m) have typical mean vitrinite reflectance of 0.6 percent; however, mean vitrinite reflectance in correlative outcrops about 15 mi (25 km) to the north is generally between 1.0 and 1.5 percent (Snively and Kvenvolden, 1989).

Timing and migration of hydrocarbons.—Migration has occurred from the late Miocene (after deposition of the reservoir rocks) to the present. Westward and upward migration along thrust faults within the Ozette and Hoh source-rock units seems likely (Snively and Kvenvolden, 1989). In the western part of the area, Ozette and Hoh source rocks are overlain by reservoir sandstone units, and there is

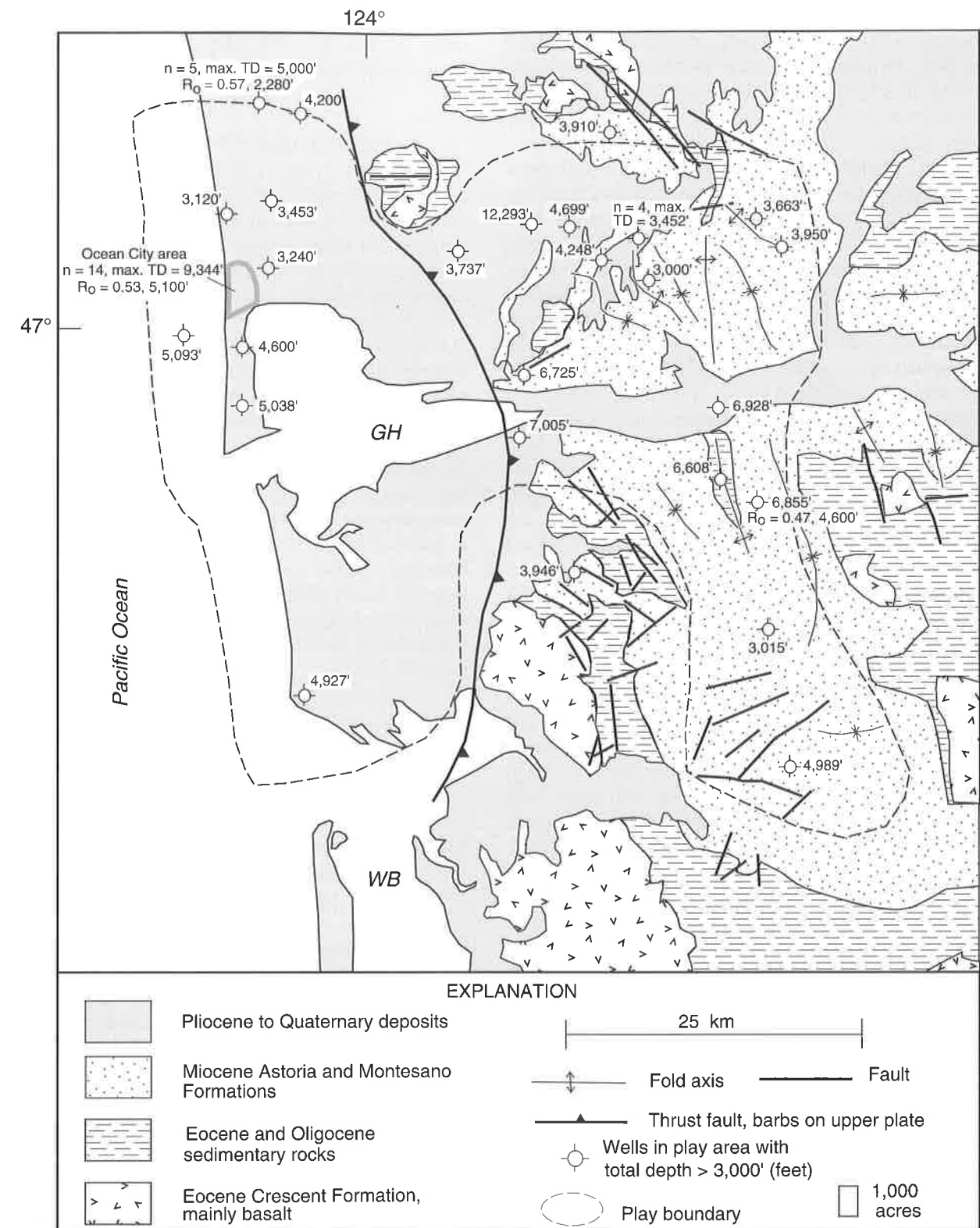


Figure 10. Schematic map showing Southwest Washington Miocene Sandstone play (406). Petroleum wells are listed in McFarland (1983) or in addendum to McFarland available through the Washington Division of Geology and Earth Resources. Geology (including selectively displayed faults and folds) is based on Walsh and others (1987). Thermal maturity data (R_0 = mean vitrinite reflectance) is from Snively and Kvenvolden (1989) and Palmer and Lingley (1989); values for vitrinite reflectance are from surface samples unless footage from adjacent petroleum well is listed. GH, Grays Harbor. WB, Willapa Bay.

a direct migration pathway from inferred source to reservoir. In the eastern part of the play area, petroleum sourced from lower-plate melange and broken formation must migrate through a thick Eocene to Oligocene section of volcanic and sedimentary rocks in order to reach Miocene sandstone reservoirs.

Traps.—Small anticlinal traps that are either associated with thrust or strike-slip faults or with mudstone diapirs in the underlying melange and broken formation are the most likely traps (Palmer and Lingley, 1989). Stratigraphic pinch-outs of Montesano Formation sandstone beds are less likely traps. Upper Miocene to Pliocene marine mudstones (in the upper part of and above the Montesano Formation) form possible seals. Closure on anticlinal traps cannot be demonstrated with available data and, if present, is probably no more than 1,000 acres (4 km²).

Exploration status.—There is no known ongoing exploration in the area of this play. About 70 wildcat wells have been drilled in the area of this play since 1901 during several discrete exploration phases (McFarland, 1983; Palmer and Lingley, 1989). The deepest and most recent well, the Amoco-Weyerhaeuser No. 1-29, was abandoned in 1985 at a total depth of 12,293 ft (3,747 m).

Evaluation of resource potential.—The Southwest Washington Miocene Sandstone play (406) has limited potential. Most oil and gas shows and the only hydrocarbon production in this geographic area have come from the underlying melange. There is clearly source and reservoir rock for this play, and evidence from borehole shows and drill-stem tests indicate that there has been some petroleum migration through potential sandstone reservoir units (Palmer and Lingley, 1989). Overlying seals have been breached in parts of the play (especially the western part), and trap and seal integrity is regarded as the principal limiting factor for petroleum accumulation.

For the recent U.S. Geological Survey 1995 National Assessment of United States Oil and Gas Resources (Gautier and others, 1995), Johnson and Tennyson (1995) assessed the probability of suitable charge, reservoir rock, and trap for an oil accumulation at 1.0, 1.0, and 0.15, respectively, yielding an overall play probability of 0.15 for a deposit larger than 1 MMB (table 1). The median number of undiscovered oil accumulations larger than 1 MMBO was estimated to be 2. The size of the largest accumulation expected at a 5 percent probability was estimated to be 14 MMBO using the following simulation parameters and the methodology of Dolton and others (1987): Area of closure = 1,000 acres (4 km²); reservoir thickness = 40 ft (12 m); effective porosity = 25 percent; trap fill = 0.8; recovery factor = 0.30; water saturation = 0.27. The mean undiscovered oil resource in the Southwest Washington Miocene Sandstone play was estimated to be 1.1 MMB (table 2).

Johnson and Tennyson (1995) assessed the probability of suitable charge, reservoir rock, and trap for a gas accumulation at 1.0, 1.0, and 0.1, respectively, yielding an overall

play probability of 0.1 for a gas deposit larger than 6 BCF. Given this low play probability, the mean undiscovered gas resource was not estimated.

COWLITZ-SPENCER GAS PLAY (407)

Introduction.—In Washington, this play is located in the southern Puget Lowland and the southwestern Coast Range of Washington (figs. 1, 3, 11). Johnson and Tennyson (1995) show the play extending south into Oregon where it includes the Mist gas field (approximately 70 BCF; Bruer, 1980; Armentrout and Suek, 1985; Niem and others, 1994; H.J. Meyer, Oregon Natural Gas Co., oral commun., 1995); however, only the Washington portion of the play is considered in this report. The play has an irregular shape and includes portions of the Chehalis, Grays Harbor, Nehalem, and Astoria basins. Uplifts of Tertiary volcanic rocks, including the Black Hills, Willapa Hills, the Doty Hills, and highlands east of Centralia and Longview, locally define play boundaries (fig. 11). For the purposes of this report, the play is bounded on the south by the Oregon-Washington State boundary, on the east by volcanic rocks of the Cascade Range or tightly folded and faulted Eocene strata in the Cascade Range foothills, and on the northwest and west by a facies change that results in the disappearance of the Eocene reservoir rock.

Eocene strata that form the potential petroleum system were deposited on a basement of lower to lower middle Eocene basalt of the Crescent Formation. These strata are cut by reverse, thrust, normal, and strike-slip faults with displacements as large as a few kilometers (Snively and others, 1958; Wells, 1981; Wells and Coe, 1985). Beds typically have gentle dips but locally have steep dips adjacent to faults. Deformation generally decreases from east to west.

Using the Mist gas field (Bruer, 1980; Armentrout and Suek, 1985) as an analog, the exploration premise for this play is that gas generated from Eocene marine shale or non-marine carbonaceous shale and coal has migrated into reservoirs in overlying or interbedded Eocene fluvial, shallow-marine, or submarine-fan sandstone. Structural traps for reservoirs are mainly fault blocks, but might include small anticlines. Stratigraphic traps are also possible but have not been documented. Interbedded fine-grained rocks and (or) overlying marine mudstone form the seals.

Reservoirs.—Middle to upper Eocene fluvial, deltaic, shallow-marine, and submarine-fan arkosic sandstone of the Cowlitz, Skookumchuck, and McIntosh Formations are the potential reservoir rocks. Analysis of outcrops and geophysical borehole logs indicates that the sandstone bodies that are potential reservoirs within these formations are as thick as about 170 ft (52 m) (Henricksen, 1956; Snively and others, 1958; Wurden and Ford, 1976; Flores and Johnson, 1995). Sandstone is predominantly arkosic. Skookumchuck Formation sandstone in the Jackson Prairie gas storage wells in the

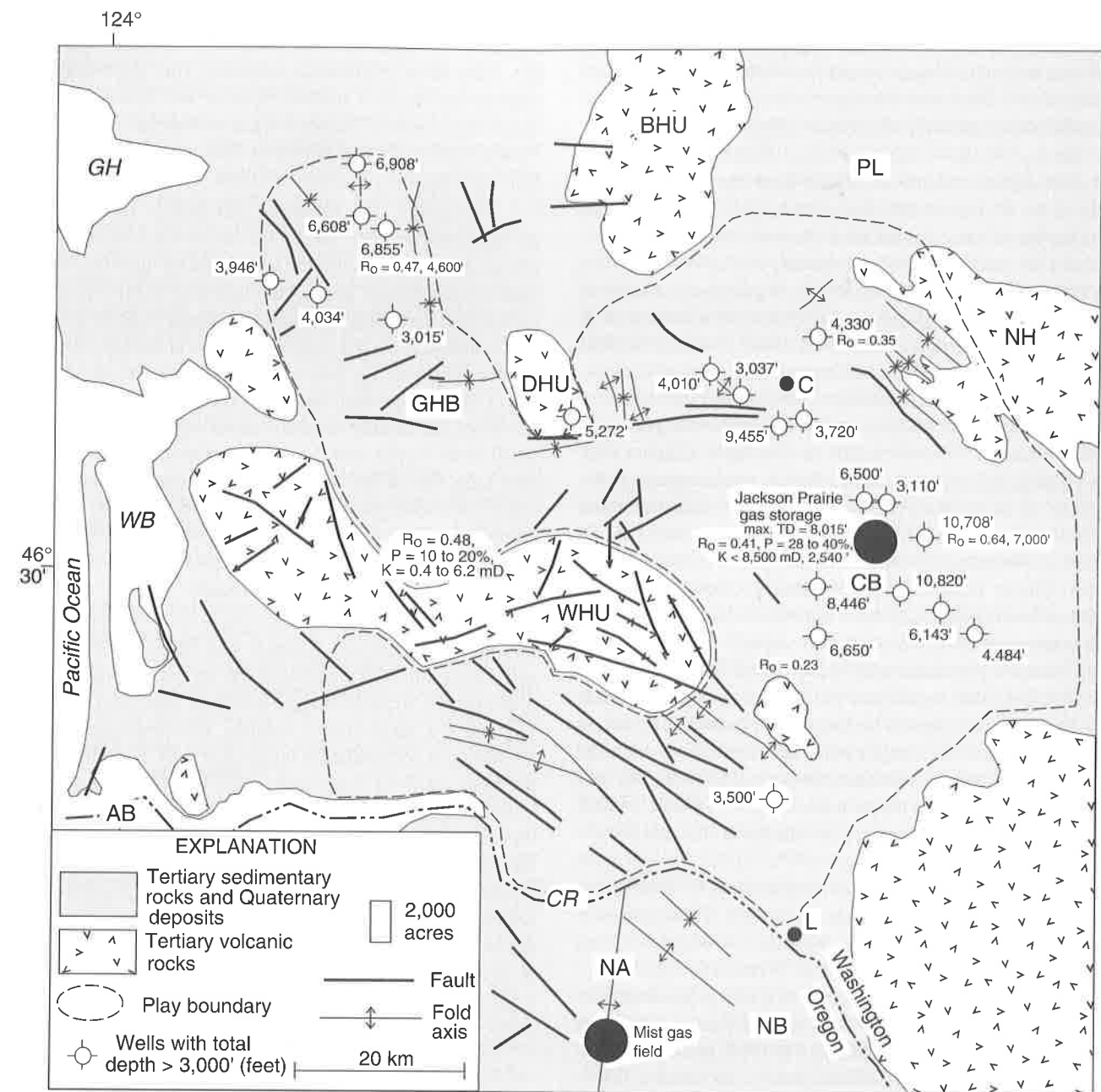


Figure 11. Schematic map showing Washington portion of Cowlitz-Spencer Gas play (407). Geology (including selectively displayed faults and folds) is based on Walsh and others (1987) and Walker and MacLeod (1991). Petroleum wells in Washington are listed in McFarland (1983) or in addendum to McFarland available through the Washington Division of Geology and Earth Resources. Thermal maturity data (R_o = mean vitrinite reflectance), porosity (P), and permeability (K , in millidarcies) is from Wurden and Ford (1976), Walsh and Lingley (1991), Moothart (1992), or previously unpublished data; values are from surface samples unless footage from adjacent petroleum well is listed. AB, Astoria basin; BHU, Black Hills uplift; C, Centralia; CB, Chehalis basin; CR, Columbia River; DHU, Doty Hills uplift; GH, Grays Harbor; GHB, Grays Harbor basin; L, Longview; NA, Nehalem arch; NB, Nehalem basin; NH, uplands underlain by Northcraft Formation, PL, Puget Lowland; WB, Willapa Bay, WHU, Willapa Hills uplift.

Chehalis basin has porosities of 30 to 40 percent at depths of 1,500 to 3,000 ft (457 to 914 m) and permeabilities as high as several darcies (Wurden and Ford, 1976). These values are comparable to those reported from the Mist field of northwest Oregon, where Cowlitz Formation reservoir rocks

have porosities of 25 to 36 percent and permeabilities of 100 mD to several darcies (Armentrout and Suek, 1985; Niem and others, 1994).

Deep-marine sandstone of the McIntosh Formation in the western part of the play has reported porosities of 10 to

22 percent, but measured permeabilities are less than 6.2 mD (Moothart, 1992). Porosity in these rocks is commonly occluded by smectite and chlorite rim cements, zeolites, and sparry calcite. Some secondary porosity results from dissolution of feldspar and lithic fragments (Moothart, 1992).

Source rocks.—Middle to upper Eocene marine shale and (or) shallow-marine to deltaic coal and carbonaceous shale of the McIntosh, Skookumchuck, and Cowlitz Formations are the inferred source rock (Snively and others, 1958; Armentrout and Suek, 1985; Moothart, 1992; Niem and others, 1994; Flores and Johnson, 1995). Organic matter in these rocks is terrestrial and gas prone. Cumulative thickness of Eocene coal beds in the eastern part of the area is more than 80 ft (24 m). Coal beds sampled at the surface and in the subsurface down to about 10,000 ft (3,048 m) are of lignite to subbituminous rank; mean vitrinite reflectance is generally between 0.3 and 0.6 percent but can be slightly higher (fig. 11) (Walsh and Lingley, 1991). In the western part of the play, the mean vitrinite reflectance of marine mudstone at the surface and in the shallow subsurface (less than 5,000 ft; 1,524 m) is generally 0.4 to 0.5 percent, and total organic carbon ranges from 0.5 to 1.25 percent (Moothart, 1992). Enhanced maturation may have occurred adjacent to Eocene and younger intrusive centers that occur within or on the margins of the play area (e.g., Esposito and Whitney, 1995).

There is also significant potential source rock in this play that does not crop out and has been penetrated by only a few boreholes in the deeper parts of basins. For example, unpublished proprietary seismic data reveal the presence of a thick section of marine strata at depths of 6,500 to 16,400 ft (1,981 to 4,999 m) below the Chehalis basin (fig. 11) (Krehbiel, 1993; Johnson and Stanley, 1995).

Timing and migration of hydrocarbons.—Maximum burial and inferred generation and migration of hydrocarbons occurred in the early to middle Miocene, following deposition of the Oligocene Lincoln Creek Formation (fig. 2).

Traps.—The structural style of this play is illustrated by the Mist field of the northern Oregon Coast Range, where gas is produced from pools (about 1 to 8 BCF) in multiple, small, fault-block traps (Bruer, 1980; Bruer and others, 1984; Armentrout and Suek, 1985; Niem and others, 1992, 1994). Entrapment could also occur in gentle anticlines or along stratigraphic pinch-outs of nearshore or deltaic sandstone bodies. There has been ongoing tectonism in the area of this play since the Eocene; thus, fault-block traps might have formed before, during, or after peak hydrocarbon generation. Overlying fine-grained marine siltstones of the Keasey and Lincoln Creek Formations provide an efficient seal. Traps associated with good reservoir rocks probably occur between about 1,000 and 7,000 ft (305 and 2,134 m).

Exploration status.—Despite the presence of the nearby Mist field in northwest Oregon, there has been only marginal exploration interest in the southwest Washington part of this play. About 20 wells with depths greater than 3,000 ft (914 m) have been drilled in the approximately 1,900-mi² (5,000

km²) area (McFarland, 1983). Most of these wells were drilled in the late 1950's or early 1960's, after which there has been little exploration activity. The 1960's wave of exploration resulted in development and numerous subsequent expansions of the natural gas storage facility at Jackson Prairie (operated by Washington Natural Gas) in the Chehalis basin (fig. 11) (Wurden and Ford, 1976).

Evaluation of resource potential.—In the Cowlitz-Spencer Gas play (407), the relatively low maturity of source rocks is probably the largest factor limiting development of significant gas accumulations. In the Washington part of the play, there also does not appear to be an analog for the Nehalem arch, the regional structural feature considered most responsible for petroleum migration into the Mist gas field (Armentrout and Suek, 1985; Niem and others, 1994). However, the smaller scale structural style at Mist (numerous small fault blocks and fault-block traps) typifies the entire play area. Given this structural style, there should be a few small gas accumulations in Washington. Because the Washington portion of this play has been poorly explored, considerable drilling may be needed before a clear strategy for finding these small traps is developed.

For the recent U.S. Geological Survey 1995 National Petroleum Assessment (Gautier and others, 1995), Johnson and Tennyson (1995) assessed the probability (in the entire play area) of suitable charge, reservoir rock, and trap at 1.0, 1.0, and 1.0, respectively, yielding an overall probability of 1.0 for a gas accumulation larger than 6 BCF (table 1). Using the Mist gas field as an analog, the size of the largest accumulation expected in the entire play at a 5 percent probability was estimated to be 150 BCF. We feel this overall probability also applies to the restricted Washington portion of the play. Based on our evaluation of the geologic framework and petroleum geology of this play, we estimate a median of four undiscovered gas accumulations larger than 6 BCF for the Washington portion of the play (10 for the entire play) and estimate the mean undiscovered resource for the Washington portion of this play to be 116 BCF (table 2).

NORTHWESTERN COLUMBIA PLATEAU GAS PLAY (501)

Introduction.—This hypothetical gas play (fig. 12) is located in south-central Washington within one or more nonmarine Paleogene transtensional and (or) extensional basins (Gresens, 1982; Johnson, 1985; Taylor and others, 1988; Catchings and Mooney, 1988; Evans, 1994; Jarchow and others, 1994) that were buried during the Miocene by flood basalts of the Columbia River Basalt Group. The area of the play is defined by the inferred sub-basalt extent of these Paleogene fluvial and lacustrine sedimentary rocks, which consist of arkosic sandstone, mudstone, conglomerate, and minor coal interbedded with volcanic and volcanoclastic rocks. The thickness of the prospective section ranges from

about 4,000 to 20,000 ft (1,219 to 6,096 m) or more, based on thicknesses of exposed sequences at the northwest margin of the play. The northeastern boundary of the play lies between wells to the northeast in which the Paleogene sequence is absent and wells to the southwest where it is present; the boundary approximately coincides with a major crustal boundary postulated by Reidel and others (1994) that roughly follows the projection of the Entiat fault (fig. 12), the northeastern margin of the exposed Paleogene sequence. The southwest boundary of the play is the approximate southeastward projection of southeast-trending splays of the Straight Creek fault zone (Tabor and others, 1984). The northern margin of the play is placed at the northern limit of continuous exposures of the Columbia River Basalt Group. The southern boundary of the play is placed along the Columbia River. The play is about 125 mi (201 km) long and 60 mi (97 km) wide.

The middle to late Miocene Columbia River Basalt Group dominates the surface geology of the area. Geophysical data (Stanley, 1984; Catchings and Mooney, 1988; Jarchow and others, 1994) indicate that it is about 10,000 to 15,000 ft (3,280 to 4,572 m) thick in the south-central part of the play; Orange and Berkman (1985) interpreted a basalt thickness of almost 20,000 ft (6,096 m) on the basis of magnetotelluric data in the southern part of the play. Two exploration wells penetrated more than 10,000 ft (3,048 m) of the Columbia River Basalt Group in the central part of the play, and six other wells penetrated 5,000 to 8,000 ft (1,524 to 2,438 m) of this unit (table 3).

The Columbia River Basalt Group unconformably overlies thick, folded Paleogene strata on the northern margin of the play. Paleogene units include the lower Eocene Swauk Formation (Tabor and others, 1982, 1984; Taylor and others, 1988), the middle to upper Eocene Chumstick (Evans, 1988, 1991, 1994) and Roslyn (Walker, 1980; Barnett, 1985) Formations, and the upper Eocene or lower Oligocene Wenatchee Formation (Gresens and others, 1981; Gresens, 1983; Tabor and others, 1982; Hauptman, 1983) (fig. 2). Exploratory drilling (fig. 2, table 3) and corroborative seismic and magnetotelluric surveys (Stanley, 1984; Jarchow and others, 1994; Lutter and others, 1994) have confirmed that these strata extend beneath the basalt at least 30 mi (48 km) southeastward from the exposures at the northwestern margin of the play. Predominantly arkosic sandstone bodies within these nonmarine units are the potential reservoirs for the play.

In the western part of the play, uppermost Oligocene to Quaternary calc-alkaline volcanic rocks of the Cascade arc overlie the Paleogene sequence and also overlie, interfinger with, and underlie the Columbia River Basalt Group. These strata have been also been encountered in some of the exploration wells below the Columbia River Basalt Group. Large, dominantly east-west-trending folds and generally north-verging reverse faults of the Miocene to Quaternary Yakima fold belt deform the basalt, most notably in the

western part of the play. This play also includes a major north-northwest-trending fold, the Hog Ranch-Naneum Ridge anticline, that lies along the trend of the Leavenworth fault and the southwest margin of the Chumstick basin. A well drilled on this high encountered a reduced thickness of basalt, and Campbell (1989) concluded that it was a pre-basalt topographic high that limited eastward transport of Cascade-derived volcanoclastic rocks.

The exploration premise for this play is that gas and gas condensate was generated from coal or organic-rich fluvial or lacustrine mudstone in Paleocene or Eocene nonmarine strata beneath the basalt and migrated into Paleogene sandstone reservoirs. Traps are postulated to be either (1) Neogene structural traps typified by the large-amplitude east-trending folds and reverse faults of the Columbia River Basalt Group, (2) upper Eocene to Oligocene structural traps, or (3) stratigraphic traps, caused by lateral facies changes, variations in porosity and permeability, or stratigraphic truncations. Drilling density in this play is approximately one well per 2,800 mi² (7,200 km²), making the Columbia basin one of the least explored sedimentary basins in the contiguous United States.

Reservoirs.—Potential reservoirs are Eocene or Oligocene arkosic fluvial sandstone beds of the nonmarine Swauk, Chumstick, Roslyn, Manastash, and Wenatchee Formations and coeval units. These units are all exposed on the northern and western margins of the play, where they are interbedded with substantial thicknesses of volcanic rocks. The drilled sub-basalt thickness (table 3; also Campbell and Reidel, 1994) of these nonmarine strata in the northern and central parts of the play ranges from less than 5,000 ft to more than 11,000 ft (1,524 to 3,353 m). Sandstone bed thickness (based on log interpretation) averages 26 ft (7.9 m) and is as thick as 81 ft (24.7 m). Lingley and Walsh (1986) suggested that these strata are likely to be only fair reservoir rocks; their analysis of geophysical logs of several wells indicated that porosity typically decreases downward within sub-basalt strata from a mean of 18 percent at 6,000 ft (1,829 m) to a mean of 6 percent at 15,000 ft (4,572 m).

The lower to middle Eocene Swauk Formation (Taylor and others, 1988; Evans and Johnson, 1989) is exposed in the Swauk basin between the Leavenworth and Straight Creek fault systems. It is more than 15,744 ft (4,800 m) thick and comprises several facies ranging from proximal fanglomerates to fine-grained lacustrine rocks. Taylor and others (1988) described braided- and meandering-river sandstone facies that could be present in the Swauk-equivalent section beneath the Columbia River Basalt Group. These fluvial deposits consist of medium- to coarse-grained, cross-bedded sandstone with bed thicknesses up to about 32.8 ft (10 m) in the meandering river facies and 230 ft (70 m) in the braided river facies. The latter facies, however, is reported to have significant amounts of laumontite and limited porosity (Taylor and others, 1988). V.A. Frizzell, Jr., (unpub. data, 1982) reported porosity values between 3.1 and 5.3 percent and

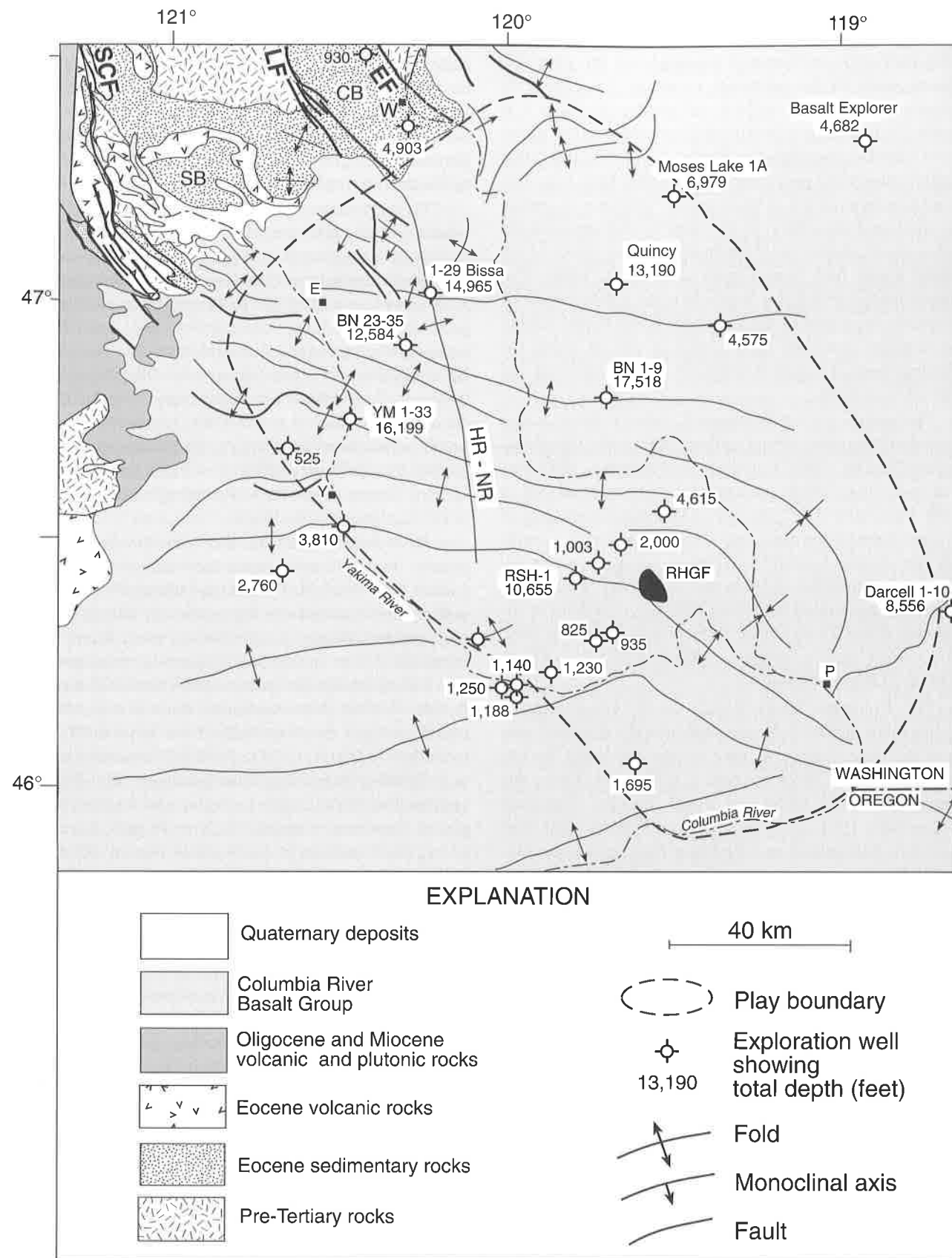


Figure 12 (facing page). Schematic map showing Northwestern Columbia Plateau Gas play (501). Exploration wells compiled from McFarland (1983), commercial Petroleum Information database (Well History Control System), and Campbell and Reidel (1994). CB, Chumstick basin; E, Ellensburg; EF, Entiat fault; HR-NR, Hog Ranch-Naneum Ridge anticline; LF, Leavenworth fault zone; P, Pasco; RHGF, Rattlesnake Hills gas field; SB, Swauk basin; SCF, Straight Creek fault zone; W, Wenatchee, Y, Yakima; YM, Yakima Minerals. Geology simplified from Walsh and others (1987), Stoffel and others (1991), and Tabor and others (1982, 1984).

permeabilities of 0.02 and 0.21 mD for four outcrop samples of the Swauk Formation. Similarly, log-interpreted porosities for strata interpreted as equivalent to the Swauk Formation near the bottom of the Yakima Minerals 1-33 well (table 3) at about 15,000 ft (4,572 m) were in the 5 to 8 percent range (Lingley and Walsh, 1986).

The middle to upper Eocene Chumstick Formation is an extremely thick sequence of fluvial and lacustrine rocks (Evans and Johnson, 1989; Evans, 1991). Total stratigraphic thickness is uncertain but has been estimated between about 19,000 ft (5,791 m) (Gresens and others, 1981) and 39,360 ft (12,000 m) (Evans, 1991). Abundant channel-form sandstone beds form multistory sequences 33 to 100 ft (10 to 30 m) thick (Evans, 1991). Composite sandstone and conglomerate units in the Chumstick Formation are as thick as 300 ft (91 m) or more (Evans, 1988). No systematic analyses of reservoir properties from outcrops of this sandstone facies have been reported. V.A. Frizzell, Jr. (unpub. data, 1982) reported low porosity and permeability from measurements on two samples of Chumstick sandstone (1.2 percent and 0.02 mD; 6.8 percent and 0.8 mD), but it is unlikely that his samples were taken from the most promising reservoir facies, and the degree of weathering is unknown. Sandstone beds assigned to the Chumstick Formation by Campbell and Banning (1985) at depths between about 13,000 ft (3,962 m) and 16,000 ft (4,877 m) in the BN 1-9 well (table 3) have log-derived porosities of only about 5 to 7 percent (Lingley and Walsh, 1986). Drill-stem tests, however, had flows of 3.1 MMCFGPD (million cubic feet of gas per day) and 6 BCPD (barrels of condensate per day) (Lingley and Walsh, 1986), indicating that at least some sandstone beds in the sub-basalt Chumstick have reservoir potential.

The middle and upper Eocene Roslyn Formation (Walker, 1980; Frizzell and others, 1984; Tabor and others, 1982, 1984; Barnett, 1985) crops out between the Leavenworth and Straight Creek fault system and is correlative with the upper part of the Chumstick Formation. It consists of about 8,200 ft (2,499 m) of fine- to coarse-grained, micaceous, partly zeolitized, poorly indurated, lithofeldspathic sandstone; coal beds are interbedded with sandstone in the upper part of the unit. Deposition took place in a south-west-flowing fluvial system (Barnett, 1985). Strata

interpreted as Roslyn Formation by Campbell and Banning (1985) were encountered in the Yakima Minerals 1-33 and 1-29 Bissa wells (table 3) at depths of 9,776 ft (2,980 m) to about 13,278 ft (4,047 m) and 4,570 (1,393 m) to about 13,610 ft (4,148 m), respectively. Lingley and Walsh (1986) used well logs to infer porosities between 4 and 18 percent at those depths. In the Yakima Minerals 1-33 well, an interval at about 13,000 ft (3,962 m) near the bottom of the inferred Roslyn tested 5,400 barrels of water per day and 570 MMCFGPD of gas, indicating adequate permeability.

The lower Oligocene Wenatchee Formation (Gresens and others, 1981; Tabor and others, 1982; Hauptman, 1983) is exposed discontinuously in several locations near Wenatchee, lying unconformably on Eocene and older strata. Campbell and Reidel's (1994) interpretation of drilling results indicated that it is present below the basalt in the eastern part of the play in the Quincy and BN 1-9 wells (table 3). It consists of as much as 984 ft (300 m) of friable coarse-grained quartz sandstone interbedded with tuffaceous shales and paleosols. Hauptman (1983) interpreted the depositional setting as a generally west-flowing fluvial system with both braided and meandering streams. The sandstone is much less feldspathic than the other Paleogene units. Campbell and Reidel (1994) reported that a water well drilled in 1993 encountered about 60 ft (18 m) of Wenatchee Formation channel sandstone that produced several thousand gallons per minute of water at almost 100 psi pressure, along with a little gas, suggesting that this unit could be an excellent gas reservoir. Sandstone interpreted as Wenatchee Formation (Campbell, 1989) between about 11,200 ft (3,414 m) and 13,000 ft (3,962 m) in the BN 1-9 well (table 3) has porosities of about 9 to 17 percent, and drill-stem tests had flows of 2.4 MMCFGPD and 134 barrels of water per day (Lingley and Walsh, 1986).

Source rocks.—Potential source rocks are lacustrine and fluvial shales in the Swauk and Chumstick Formations and coal beds in the Roslyn Formation. Reported TOC (total organic carbon) values from outcrops are 0 to 6 percent (0.03 to 1.10 percent in the Swauk Formation; 0.92 to 17.9 percent in the Roslyn Formation; 0.13 to 5.97 percent in the Chumstick Formation (V.A., Frizzell, Jr., unpub. data)). Pyrolysis data on cuttings samples from the Yakima Minerals 1-33 and Bissa 1-29 wells indicates that each penetrated more than 1,200 ft (366 m) of section (including thin coal beds) that averaged more than 2.5 percent TOC (Core Laboratories, 1987a, 1987b; Lingley and von der Dick, 1991). Organic matter is mostly types III and IV but includes minor type II (Peters, 1986), the probable source of the paraffinic condensate (37° to 52° API gravity) recovered during a drill-stem test.

Mean vitrinite reflectance values in exposed rocks on the northern margin of the play were reported to range from 0.24 to 1.38 percent (0.82 to 1.29 percent in the Swauk

Table 3. Summary of information on wells with total depth greater than 5,500 ft drilled in the Northwestern Columbia Plateau Gas play (501).
[Stratigraphy based on Campbell (1989), Campbell and Banning (1985), and Lingley and Walsh (1986). Unless indicated, ages of units are shown in figure 2. MMCFGPD, millions of cubic feet of gas per day; BWPD, barrels of water per day]

County	Township	Range	Section	Elevation (ft)	Operator	Lease	Year	TD (ft)	Rock unit at TD	Eocene to Oligocene sedimentary section reported	Drill-stem tests (DST)
Benton	11	24	15	2,872	Standard Oil	Rattlesnake Hills 1	1958	10,655	Columbia River Basalt (Miocene)	None	None
Kittitas	15	19	33	1,306	Shell Western E&P Inc	Yakima Minerals 1- 33	1982	16,199	Swauk Formation (Eocene)	Roslyn Formation, 9,776 to 13,278 ft; Swauk Formation, 13,980 to 16,199 ft	6 DSTs: 12976-13568 ft, 570 MMCFGPD; 5400 BWPD; 12,450-12,460 and 12,350-12,360 ft, 500 MMCFGPD; 11,676- 11,686 ft, 11,564-11,574 ft, and 11,598-11,652 ft, 85 MMCFGPD; 10,604-10,930 ft, 10 MMCFGPD; 7,535-8,040 ft, 27 MMCFGPD, 5,360-5,397 ft, 25-50 MMCFGPD
Kittitas	15	19	33	1,306	Shell Western E&P Inc	Yakima Minerals 2- 33	1982	5,604	Wildcat Creek unit (Oligocene volcaniclastic rocks)	None	
Kittitas	18	21	29	3,879	Shell Western E&P Inc	Bissa 1-29	1982	14,965	Granitic conglomerate, Swauk Fm. (Eocene)	Roslyn Formation, 4,570 to 13,610 ft; Swauk Formation, 13,610 to 14,965 ft	Numerous gas zones; 3 DST's (from 10,314-10,898, 9,436- 9,830, and 8,486-8,800 ft); no sustained gas flow
Grant	15	25	9	2,408	Shell Western E&P Inc	BN 1-9	1984	17,518	Roslyn Formation (Eocene)	CRBG 0, Wenatchee ~11,500 ft, Ohanepecosh ~12,100 ft, Roslyn ~13,050 ft	12 gas zones: 4 DST's; 12,694- 12,699 ft, 2.4 MMCFGPD and 134 BWPD; 13,372-13,388 ft, 3.1 MMCFGPD, 6 BWPD
Walla Walla	10	33	10	868	Shell Western E&P Inc	Darcell 1-10	1988	8,556	Pre-Tertiary crystalline rock to 8,200 ft	Eocene sedimentary rocks, about 8,100	No information
Grant	18	25	22	1,158	Shell Western E&P Inc	Quincy	1989	13,200	Pre-Tertiary basement	Wenatchee Formation, about 7,600 to 8,000 ft; Roslyn or Chumstick Formation, about 10,500 to 13,000 ft	Perforations from 8,765-8,915 ft and 8,779- 8,886 ft produced gas (too small to measure) and water DST from 11,919-12,584 ft, no information available
Kittitas	17	20	35	2,837	Meridian	BN 23-35	1989	12,584	Teanaway Fm. (Eocene)	Roslyn Formation, about 6,900 to 12,500 ft	

Formation; 0.45 to 1.38 percent in the Roslyn Formation; 0.25 to 0.89 percent in the Chumstick Formation; V.A. Friz-
zell, Jr., unpub. data). Evans (1994) reported vitrinite reflec-
tance values between 0.40 and 2.08 percent for surface
outcrops of the Chumstick Formation. Lingley and Walsh
(1986) reported vitrinite reflectance measurements from
subsurface coals sampled in four wells, including three that
penetrated basalt (table 3). In two of these wells, mean vit-
rinite reflectance values indicated only marginal maturity
(maximum values of about 0.6 to 0.7 percent), but for
sub-basalt sections in the other two wells, maximum values
range from 1.3 to 1.4 percent, suggesting that the coals could
have generated gas.

Isotopic data demonstrate the presence of thermogenic
gas, probably derived from coals in sub-basalt strata, in
intra-basalt aquifers in the southern part of the play (Johnson
and others, 1993). Nineteen water wells located between
Yakima and Pasco have tested gas, and several have had
degassing equipment installed.

Timing and migration of hydrocarbons.—Lopatin
modeling suggests that maturation of lower Eocene rocks
may have begun in the Oligocene, while maturation of mid-
dle Eocene and younger source rocks probably took place
during the Miocene during burial by 5,000 to 13,000 ft
(1,524 to 3,962 m) of the Columbia River Basalt Group
(Tennyson and Parrish, 1987). The presence of marginally
mature sedimentary interbeds in the lower part of the basalt
sequence (Lingley and Walsh, 1986; T. Walsh, Washington
Department of Natural Resources, oral commun., 1987) is
also consistent with Miocene maturation. Blackwell and oth-
ers (1985) indicate that the geothermal gradient in the
Columbia basin now ranges from 28°C to 58°C/km, suggest-
ing that the onset of peak gas generation could be presently
occurring at about 7,000 ft (2,134 m) in parts of the basin.

Traps.—The best potential structural traps appear to be
the large, Miocene and younger anticlines and fault-block
traps associated with deformation of the Columbia River
Basalt Group. Dipmeter data suggest that some pre-basalt
strata penetrated in the Yakima foldbelt wells conform with
structure mapped at the surface. However, some workers
(e.g., Saltus, 1993; Campbell and Reidel, 1994) have sug-
gested that the youngest folds may not extend downward
into the pre-basalt sedimentary strata, and that sub-basalt
structural highs are not coincident with fold crests in basalt.
Eocene through early Miocene fold, fault, and stratigraphic
traps are also possible but cannot be readily located beneath
the thick basalt cover with present technology. The most
probable seals consist of shale interbeds in the fluvial
sequences or permeability barriers resulting from differences
in cementation or zeolitization.

Exploration status.—The only historical production for
this play was from the small Rattlesnake Hills gas field on
the east-southeast-trending Rattlesnake Hills anticline (fig.
12). The field was discovered during the drilling of a water
well in 1913, developed about 1930 after venting an

unknown amount of gas to the surface from open wells, and
abandoned in 1941. Total production was an estimated 1.3
BCFG (McFarland, 1979). Hammer (1934) reported gas
composition of 97.25 percent methane, 2.45 percent nitro-
gen, and 0.15 percent each oxygen and carbon dioxide. In
contrast, Wagner (1966) reported more than 80 percent
methane and about 10 percent nitrogen. Neither analysis
reported ethane or heavier hydrocarbons. The gas was
trapped in a faulted anticline between two vesicular zones in
basalt flows sealed by clay interbeds, at depths between 700
and 1,300 ft (213 to 396 m) (Hammer, 1934). The gas was
probably generated from coal within or below the basalt
(Johnson and others, 1993) or from a biogenic source
(Stevens and McKinley, 1995). In 1958, a deep test (Stan-
dard Oil Rattlesnake Hills No. 1) was drilled to 10,655 ft
(3,248 m) about 10 mi (16 km) west of the Rattlesnake Hills
gas field, but the well did not record any gas shows. The
rocks at the bottom of the well were volcanic and are
believed by S.P. Reidel (Washington State University, oral
commun., 1989) to belong the Columbia River Basalt
Group.

Between 1980 and 1989, seven important test wells
were drilled in the northwestern Columbia basin to depths of
5,604 to 17,518 ft (1,708 to 5,339 m) (table 3). All were
located on the crests of large anticlines in Columbia River
Basalt Group, including one sited near the intersection of the
northwest-southeast-trending Hog Ranch-Naneum Ridge
anticline and the east-west-trending Frenchman Hills anti-
cline. Most of the wells had gas shows, and drill-stem tests
were run in at least four of the wells. Notable test results
included 5.4 MMCFGPD and 6 BWPD in the Shell Oil
Company BN 1-9, and 570 MMCFGPD in the Yakima Min-
erals 1-33. The widespread occurrence of gas in these wells
indicates that gas accumulations are almost certainly present,
but the generally "tight" character of sub-basalt sandstones
appears to limit the chances for easily produced discoveries,
unless strategies for locating particularly good reservoir
facies can be developed.

Resource potential.—This play is considered to have a
high probability of at least a few, and possibly many, small
gas accumulations and a lower probability of large gas accu-
mulations. Significant subcommercial flows of gas were
tested in several of the wells that penetrated the basalt, but it
has not been demonstrated that reservoir strata are of ade-
quate quality, thickness, and lateral persistence to contain a
conventional gas accumulation larger than a few tens of
BCFG, despite the possible presence of traps big enough to
hold hundreds of BCFG. The thick basalt cover and associ-
ated difficulty this presents for exploration and the generally
poor character of potential reservoir sandstones are the pri-
mary discouraging factors for future exploration of this play.

For the recent U.S. Geological Survey 1995 National
Petroleum Assessment (Gautier and others, 1995), Tennyson
(1995) assessed the probabilities of suitable charge, reservoir
rock, and trap at 1.0, 0.6, and 1.0, respectively, yielding an

overall play probability of 0.6 for a gas accumulation larger than 6 BCF (table 1). The size of the largest accumulation expected at a 5 percent probability was estimated to be 1,000 BCF. This estimate is consistent with an analysis by Lingley and Walsh (1986), who postulated accumulations with areas of closure of 3,000 to 25,000 acres (12.1 to 101.2 km²), depths of 5,000 to 14,000 ft (1,524 to 4,267 m), porosity of 6 to 18 percent, and a recovery factor of 60 percent, concluding that accumulations between 40 and 1,000 BCF were possible. The number of undiscovered accumulations greater than 6 BCF was estimated to be between 1 and 100, with 10 accumulations assigned as the median. The mean undiscovered resource in the Northwestern Columbia Plateau Gas play (501) was estimated to be 235 BCFG (table 2).

CONTINUOUS-TYPE PETROLEUM ACCUMULATIONS

In this report, two kinds of continuous-type hydrocarbon accumulations are discussed, coal-bed gas accumulations and basin-centered gas accumulations. The methodology used in the 1995 National Assessment of United States Oil and Gas Resources for assessing these deposits differs from that used for conventional hydrocarbon accumulations. For detailed explanations, see Schmoker (1995) for the overall treatment of continuous-type accumulations and Rice and others (1995) for the specific treatment of coal-bed methane deposits. General characteristics of basin-centered accumulations are described in Law (1995a, 1995b).

The methodology used for estimating the recoverable gas in basin-centered gas accumulations (Schmoker, 1995) is different from that used in conventional accumulations. Within the stratigraphic interval and play area selected for analysis, a cell size is chosen. The size of the cell is based on the area expected to be drained by wells in the play area. The total number of cells in a play equals the area of the play (mi²) divided by the cell size (mi²). Because of uncertainties involved in the determination of the play area and cell size, these values are treated as a frequency distribution. The next step in the methodology is to establish an estimate of the ultimate recovery (EUR) probability distribution for the play. The EUR probability distribution is determined by selecting productive wells that are thought to be representative of the play. The EUR of those wells is then plotted as a probability distribution. This data is then entered into a computational probability program developed by Crovelli and Balay (1995). The results of the computation program are presented as a probability distribution represented as minimum (100th fractile), maximum (0th fractile), and median values (50th fractile).

COAL-BED GAS PLAYS

During the past 25 years, coal-bed gas has been produced from more than 5,400 wells in the United States and now accounts for about 6 percent of total national gas reserves and 3 percent of gas production (Rice and others, 1995). Most of the reserves and production are from the San Juan basin of Colorado, New Mexico, and Utah, and the Black Warrior basin of Alabama and Mississippi. Most aspects related to the occurrence and development of hydrocarbons from coal are discussed in Law and Rice (1993). Because of the immense quantities of coal-bed gas that could be included in resource appraisals, the U.S. Geological Survey 1995 National Assessment of Oil and Gas Resources (Gautier and others, 1995) estimated only those resources that were judged capable of being added to U.S. oil and gas reserves during the next few decades (by approximately 2020).

Coal-bed gas plays in Washington were defined on the basis of factors that control the occurrence and productivity of coal-bed gas. These factors include but are not limited to coal thickness, heterogeneity, depth, and composition of coal, seals, gas content, gas composition, permeability, pressure regime, local and regional structural setting (including folds, faults, joints, cleats), and hydrology. Hydrology is important because water production and disposal are important economic and environmental factors in field development. In general, coal-bed gas plays for potential additions to reserves extend from depths of 500 to 6,000 ft (152 to 1,829 m) below the surface.

Rice and others (1995) describe in detail the methodology used to assess coal-bed gas plays. Briefly, this method involves the following: (1) defining and describing the coal-bed gas play based on geologic criteria (discussed above); (2) compilation of available relevant geologic data needed for geological/engineering, computational, and economic assessment; (3) subdivision of the specific play area into cells that generally equal the coal-bed gas well spacing authorized by State regulatory agencies and determining the number of untested cells in the play; (4) estimating the success ratio (values of 0 to 1.0) of untested cells in the coal-bed gas play that are anticipated to produce gas; (5) Determining the probability distribution of estimated ultimate recoveries (EUR) from wells in potentially productive untested cells, and (6) Estimating the probability (values of 0 to 1.0) that one or more of the untested cells in the play will produce at least the minimum EUR estimated for cells within the play. Many of these steps rely on development of analogs and reservoir simulations from the productive San Juan and Black Warrior basins. Three coal-bed gas plays are identified in Washington and are described below.

WESTERN WASHINGTON—BELLINGHAM BASIN PLAY (450)

Introduction.—This coal-bed gas play occupies the same area as the conventional Bellingham Basin Gas play (401) (figs. 3, 4, 5), and the geologic setting of this area is described above under that play. Coals of the Paleocene(?) to Eocene Chuckanut Formation are the potential gas reservoirs in this play.

Coal occurrence.—Coals of the Lake Whatcom zone and Bellingham interval of the Chuckanut Formation (Beikman and others, 1961) are exposed on the southern margin of the Bellingham basin and should continue in the subsurface of the basin to the north (fig. 5). The Lake Whatcom zone includes about five coal beds ranging in thickness from 2 to 9 ft (0.6 to 2.7 m) (Beikman and others, 1961). The Bellingham interval contains two beds with thicknesses of 14 ft (4.3 m) and 2 ft (0.6 m) (Beikman and others, 1961). One of these two intervals is probably correlative with the King Mountain interval, recognized in the basin subsurface (P.D. Hurst, Canadian Hunter Exploration, Ltd., written commun., 1992). The King Mountain coal zone contains five to eight coal beds with a mean bed thickness of 5 ft (1.5 m) and no beds thicker than 10 ft (3.0 m). The King Mountain coal interval has been penetrated at depths ranging from 1,700 to 3,700 ft (518 to 1,128 m), depending on the location and structural position of the well. Conchoidal fractures were observed in sidewall cores of these coals, a positive indicator of a permeable cleat system (P.D. Hurst, Canadian Hunter Exploration, Ltd., written commun., 1992). Otherwise, there is no information on joints and cleats.

Coal maturity.—The mean vitrinite reflectance of coals in the King Mountain interval ranges from 0.5 to 0.55 percent at depths of about 1,700 ft (518 m) (P.D. Hurst, Canadian Hunter Exploration, Ltd., written commun., 1992). Mean vitrinite reflectance in coal exposed on the south flank of the basin is 0.74 percent (Walsh and Lingley, 1991).

Coal resources.—Beikman and others (1961) estimated reserves of approximately 310 million short tons (281 million metric tons) for coal beds more than 14 inches (36 cm) thick at depths of less than 3,000 ft (914 m) in and on the flanks of the Bellingham basin. Moen (1969) and Vonheeder (1977) subsequently raised the estimate to 366 million short tons (332 million metric tons), of which about 37 percent is measured or indicated and about 63 percent inferred. There are no active coal mines in or on the margins of the Bellingham basin.

Coal-bed gas exploration.—No wells have been drilled in the Bellingham basin that were designed primarily as coal-bed gas tests using current drilling and completion practices, and only four wells provide relevant information for coal-bed gas evaluation. Mud-gas responses indicate that methane and lesser propane is being liberated from coals

(P.D. Hurst, Canadian Hunter Exploration, Ltd., written commun., 1992). The propane has been attributed to the presence of type-IIIB kerogen in the coals. There is meager data on the desorbition and permeability of the coals. In one well, King Mountain coals desorbed gas at 100 ft³/short ton of coal (3.4 cm³/g), suggesting low maturity consistent with vitrinite reflectance data. Isotopic analyses of gas seeps from old well casings indicate a thermal origin with some biogenic mixing for gases (Hurst, 1991). There is no available data on water composition in subsurface coal beds.

Evaluation of resource potential.—There has been no significant exploration for coal-bed gas in the Bellingham basin, with information about possible coals deeper than 5,000 ft (1,524 m) lacking. Available information suggests that low coal rank, steep dips, and low permeability will be the main factors limiting development of a viable coal-bed gas resource. Using the meager available data from the Bellingham basin and an analog from underpressured discharge coal-bed reservoirs of the San Juan basin, Johnson and Tennyson (1995) estimated an overall play probability of 0.7, a mean of 280 untested cells, a success ratio of 0.5 for untested cells, and a mean estimate of ultimate recovery for untested cells of 413 MMCF gas. These estimates yield mean potential gas reserve additions for the entire play of 40.5 BCF (table 4).

WESTERN WASHINGTON—WESTERN CASCADE MOUNTAINS PLAY (451)

Introduction.—This coal-bed gas play occupies essentially the same region as the conventional Southeastern Puget Lowland Gas play (402) (figs. 3, 4, 6); the geologic setting of this region is described above under that play. Coals of the undifferentiated Puget Group and the Tiger Mountain, Renton, Carbonado, and Spiketon Formations (fig. 2) are the potential coal-bed gas reservoirs in this play.

Coal occurrence.—Beikman and others (1961) describe the stratigraphy of coal bearing strata at nine locations within this play: (1) Newcastle—Grand Ridge area; (2) Renton area; (3) Tiger Mountain and Niblock areas; (4) Taylor area; (5) Green River district; (6) Wilkeson—Carbonado coal field; (7) Spiketon area; (8) Fairfax—Montezuma and Ashford areas; and (9) Eastern Lewis County. Each area is characterized by its own nomenclature for coal seams. For example, the Green River district includes at least 16 coal beds assigned to the Franklin coal zone and the Kummer coal zone. These Green River district coals occur in a section about 6,300 ft (1,920 m) thick and have a cumulative minimum thickness of 73 to 90 ft (22 to 27 m) (Vine, 1969). The Green River district probably represents the area with the most coal in this play. In other areas, the coal-bearing section

Table 4. Coal-bed gas in Washington.

[Comparison of U.S. Geological Survey estimates of undiscovered technically recoverable coal-bed gas with that of other selected States and geologic provinces. Information from Gautier and others (1995) and U.S. Geological Survey National Oil and Gas Resource Assessment Team (1995, table 5). Fractile values (F₉₅, F₅) are not additive. F₉₅ represents a 19 in 20 chance and F₅ represents a 1 in 20 chance of the occurrence of at least the amount tabulated]

Selected play, State, or geologic province	Gas (trillion cubic feet)		
	F ₉₅	F ₅	Mean estimate
Western Washington—Bellingham Basin (450)	0.00	0.09	0.04
Western Washington—Western Cascade Mountains (451)	0.00	0.93	0.54
Western Washington—Southern Puget Lowlands (452)	0.00	0.27	0.12
TOTAL, Washington			0.70
Piceance basin, Colorado	5.47	10.09	7.49
San Juan basin	5.76	9.67	7.53
Southwest Wyoming	0.83	7.66	3.89
Black Warrior basin, Alabama and Mississippi	1.49	3.43	2.30
North Appalachian basin, New York, Pennsylvania, Ohio, West Virginia	7.68	16.36	11.48
TOTAL ESTIMATE, lower 48 States*	42.89	57.63	49.91

*Total for lower 48 States is not a sum of the selected areas listed on this table.

commonly interfingers with and pinches out against volcanic rocks (Gard, 1968; Vine, 1969).

The lack of uniformity in stratigraphic and coal nomenclature across this play area reflects the difficulty in correlation of units and markers induced by structural complexity, the lenticular nature of coal beds, and the presence of locally interbedded volcanic rocks. Structural relief in the play area is considerable. For example, the Franklin coal zone is being strip-mined from the axis of an anticline about 1.2 mi (2 km) north-northeast of Black Diamond (fig. 6). Nearby petroleum exploration wells have encountered the same stratigraphic level at depths of 5,000 ft (1,524 m) or more.

Coal maturity.—Mean vitrinite reflectance values in surface and subsurface coals range from 0.35 to more than 2.0 percent in the play area, increasing eastward toward the axis of the Cascade Range (Walsh and Lingley, 1991). Mean vitrinite reflectance in the surface section near Black Diamond (fig. 6) range from 0.42 to 0.68 percent. Pappajohn and Mitchell (1991) reported mean vitrinite reflectance values from coal-bed gas exploration drilling near Wilkeson (fig. 6) of 0.84 to 1.03 percent. In the eastern Lewis County area (north of Morton), mean vitrinite reflectance values range from 0.6 to 0.8 percent at the surface (as high as 2.21 percent near intrusions), and from 0.96 to 1.69 percent in the upper 2,000 ft (610 m) of the subsurface. These rocks have been uplifted and (or) deformed.

Coal resources.—Beikman and others (1961) estimated reserves of approximately 1,230 million short tons (1,116 metric tons) for coal beds more than 14 inches (36 cm) thick and at depths of less than 3,000 ft (914 m) in the area of this play. Of this amount, about 33 percent is measured or indicated and 67 percent is inferred. These estimates are

probably conservative. There is one active coal mine in this area, operated since 1986 by the Pacific Coast Coal Company near Black Diamond (fig. 6). Total production in the John Henry No. 1 mine has exceeded 1 million short tons (907,200 metric tons), and the current annual production has grown to about 300,000 short tons (272,200 metric tons) (Brownfield and others, 1994). Coal is being strip-mined along the axis of a tight anticline.

Coal-bed gas exploration.—Since 1986, 15 wells that can be broadly considered coal-bed gas wells have been drilled in the area of this play. A few wells underwent extended production testing, and good gas shows were encountered in several wells (S. Pappajohn, Carbon Energy International, oral commun., 1993). There is presently no coal-bed gas production.

Pappajohn and Mitchell (1991) report desorption values ranging from 6.8 to 17.6 cm³/g for five coal beds penetrated by drilling in the Wilkeson area (fig. 6). The history of methane-related underground mine accidents in the region and the presence of gas bubbling to the surface through ponds in the John Henry No. 1 mine are further indicators of gassy coals. Steve Pappajohn (Carbon Energy International, oral commun., 1993) reports that there are well-developed cleats in some of the coals encountered by drilling in this play area; however, there is no available data on joints, cleats and coal permeability. Pappajohn and Mitchell (1991, table 5) present analytical data from water produced from coal seams in the Wilkeson area that indicates the water meets State and Federal requirements for surface discharge.

Evaluation of resource potential.—In the Western Washington—Western Cascade Mountains play (451), available information suggests that structural complexity and (or)

poor permeability may be the limitations on developing a coal-bed gas resource. Much of the area is tightly folded and cut by faults, making exploration difficult and limiting reservoir continuity. Drilling results have also indicated that gas has locally escaped through steeply dipping coal beds that have breached the surface (S. Pappajohn, Carbon Energy International, oral commun., 1993).

Using the available data from this play and an analog from the Piceance Basin—Western Basin Margin play (2054), Colorado, Johnson and Rice (1995) estimate an overall play probability of 0.9, a mean of 1,072 untested cells, a success ratio of 0.4 for untested cells, and a mean of the EUR distribution for untested cells of 1,401 MMCF gas. These estimates yield mean potential gas reserve additions for the entire play of 541 BCF (table 4). This estimate is significantly less than previous estimates (Choate and others, 1984).

WESTERN WASHINGTON—SOUTHERN PUGET LOWLANDS PLAY (452)

Introduction.—This coal-bed gas play occupies the same region as the eastern part (east of long 123°10'W.) of the Washington portion of the conventional Cowlitz-Spencer Gas play (407) (figs. 3, 4, 11); the geologic setting of this region is described above under that play. Coal of the Skookumchuck and Cowlitz Formations are the potential coal-bed gas reservoirs (fig. 2) in this play.

Coal occurrence.—Coals belong to the upper middle to upper Eocene Skookumchuck Formation in the northern part of play and to the Cowlitz Formation in the southern part of the play. Thirteen coal beds with a cumulative thickness of about 88 ft (27 m) have been recognized in a 2,600-ft-thick (793 m) section of the Skookumchuck Formation (Snively and others, 1958). Approximately 70 ft (21.3 m) of coal in seven beds has been recognized in a 500-ft section (152 m) of the Cowlitz Formation on the southwest margin of the Chehalis basin (P. Hales, Weyerhaeuser Corp., written commun., 1995). Several coal beds occur in the subsurface of the Chehalis basin at depths as great as about 6,000 ft (1,829 m). Wireline log analysis suggests that the cumulative thickness of coal may be greatest in the Chehalis basin.

Coal maturity.—Coals in this play range in rank from lignite to subbituminous B (Beikman and others, 1961). Mean vitrinite reflectance of surface coal in the Skookumchuck Formation in the Centralia area ranges from about 0.35 to 0.40 percent, and values from subsurface coal in the Chehalis basin ranges from 0.4 to 0.7 percent (Walsh and Lingley, 1991). Coal of the Cowlitz Formation in the southern part of the play is generally of lower grade with mean vitrinite reflectance values less than 0.4 percent.

Coal resources.—Beikman and others (1961) estimated reserves of approximately 3,810 million short tons (3,456 million metric tons) for coal beds more than 14 inches

(36 cm) thick and depths of less than 3,000 ft (914 m) in the area of this play. Of this amount, about 55 percent is measured and indicated and about 45 percent is inferred. The play area includes the Centralia mine, from which approximately 100 million short tons (97 metric tons) have been produced since 1971.

Coal-bed gas exploration.—No coal-bed gas wells have been drilled in this play. The absence of exploration interest here no doubt reflects the low thermal maturity of the coals.

Evaluation of resource potential.—The most favorable aspect of the play is the great volume of relatively shallow coal. The least favorable aspect of the play is the low thermal maturity of the coal. Using stratigraphic and maturity data and an analog from underpressured discharge coal-bed reservoirs of the San Juan basin, Johnson and Rice (1995) estimate an overall play probability of 0.6, a mean of 774 untested cells, a success ratio of 0.5 for untested cells, and a mean ultimate recovery for untested cells of 500 MMCF of gas. These estimates yield mean potential gas reserve additions for the entire play of 116 BCF (table 4). This estimate is notably smaller than previous estimates of Choate and others (1984).

BASIN-CENTERED GAS ACCUMULATION PLAYS

Basin-centered gas accumulations, another type of continuous gas accumulation, also occur in many petroleum provinces. These gas accumulations, unlike discrete conventional accumulations, are regionally pervasive and sometimes extend over thousands of square miles and through thousands of feet of stratigraphic section. This resource presently accounts for approximately 10 percent of total gas production in the United States and is expected to play an even more significant role in the energy requirements of the nation in the future (National Petroleum Council, 1992).

There is no single characteristic that uniquely defines a basin-centered gas accumulation. However, the following list of attributes facilitate identification: (1) the presence of regionally extensive accumulations that occupy the more central, deeper parts of basins, (2) the absence of down-dip water contacts, (3) the presence of reservoirs that are abnormally over- or under-pressured relative to normal, hydrostatic pressures, (4) the abnormally pressured fluid phase is gas, (5) gas reservoirs are overlain by a normally pressured transition zone containing gas and water, (6) there is little or no producible water in reservoirs, (7) reservoirs have low permeability, commonly less than 0.1 mD, (8) gas is of thermogenic origin, (9) the source of gas is from interbedded and (or) adjacent rocks, (10) the distance of gas migration from the source rock is relatively short compared to migration distances that may occur in conventional accumulations, (11) the top of the gas accumulation occurs at 0.7 to 1.0 percent

vitrinite reflectance, (12) structural and stratigraphic trapping aspects are of secondary importance, and (13) the "seal" is a relative permeability barrier. Because it is unlikely that all these characteristics can be identified in any single well, the most important characteristics to recognize are abnormal pressures, thermal maturity, and the abnormal pressure fluid phase.

WILLAMETTE-PUGET SOUND BASIN-CENTERED GAS (412)

Introduction.—The Puget-Willamette Lowland trough, located immediately west of the Cascade Range in Washington and Oregon, contains several smaller basins that include the Tualatin and Nehalem basins in Oregon and the Chehalis, Tacoma, Seattle, and Everett basins in Washington (figs. 1, 6, 7, 11) (Johnson and others, 1994, 1996; Niem and others, 1994). These forearc sub-basins are filled with Eocene and younger sedimentary rocks that were deposited in nonmarine to marine depositional systems and may be as thick as 30,000 ft (9,146 m). Only a few wells have been drilled in this play area that are deep enough to determine the presence of a basin-centered gas accumulation (Law, 1995b). Subsurface data from two wells (the Exxon GPE Federal Community No. 1 well located in northwestern Oregon (Niem and others, 1994), and the Phillips State No. 1 well located east of Tacoma in the Puget Lowland (McFarland, 1983)) were drilled to depths of 11,287 ft (3,441 m) and 12,920 ft (3,939 m), respectively. The top of abnormally high reservoir pressure occurs in these wells at depths of 8,000 to 9,600 ft (2,439 to 2,926 m), and the levels of thermal maturity at these depths are about 0.8 percent mean vitrinite reflectance (Walsh and Lingley, 1991; Stormberg, 1992). These relationships, in conjunction with the presence of interbedded coal beds and low-permeability reservoirs, suggest the presence of a basin-centered gas accumulation. The spatial and areal distribution of basin-centered gas accumulations in this hypothetical play cannot be determined with available data.

Reservoirs.—Sandstone reservoirs in this play occur in Eocene and possibly older rocks. Borehole data indicate that gas-bearing reservoirs occur in an interval that is at least 3,300 ft (1,006 m) thick. The bottom of the potential basin-centered gas accumulation is not known because the entire gas-bearing interval has not been penetrated. Eocene sandstones that are likely to form reservoirs in Washington are probably arkosic in composition (Buckovic, 1978; Frizzell, 1978; Johnson and Stanley, 1995). These sandstone units contain significant proportions of lithic fragments and mica that are likely to be altered and compacted during diagenesis. No porosity or permeability data are available from the reservoirs in the overpressured interval, but qualitative estimates are low. Limited data indicate that the top of the overpressured, basin-centered gas accumulation ranges

from 8,000 to 9,600 ft (2,439 to 2,926 m). The bottom of the reservoirs is at least 13,000 ft (3,963 m).

Source rocks.—In the absence of source rock analyses, the most likely sources of gas are the interbedded coal beds and carbonaceous shales. The levels of thermal maturity at the top of the gas accumulation in the Phillips State No. 1 well (Walsh and Lingley, 1991) are sufficiently high (mean vitrinite reflectance = 0.8 percent) to generate gas from available organic matter. Published and unpublished source rock analyses from various rock units in the Pacific Northwest indicate that nearly all of the organic matter is a type-III kerogen and capable of generating mainly gas (Law and others, 1984; Sidle and Richers, 1985; Lingley and von der Dick, 1991).

Timing and migration.—Because gas is generated within, or in close proximity to reservoirs in basin-centered gas accumulations, the temporal relationships between gas generation, migration, and development of a trap are not nearly as important as they are in conventional accumulations. It is uncertain when the reservoirs penetrated by the Phillips State No. 1 and Exxon GPE Federal Community wells were charged with gas. Present-day temperatures at depths of 8,000–9,600 ft (2,439 to 2,926 m) are about 130°F to 150°F (40°C to 51°C), too low to have achieved the present level of thermal maturity at present depths. Therefore, this area has experienced higher temperatures in the past.

Traps and seals.—See the discussion of the character of traps and seals needed for basin-centered gas accumulations in the introduction to this section.

Exploration status.—The Willamette-Puget Sound Basin-Centered Gas play (412) has not been explored. Previous exploration activity in the play area has focused on traditional structural plays. Due to a lack of information, this play was not quantitatively evaluated for the 1995 National Assessment of Oil and Gas Resources (Gautier and others, 1995; Law, 1995b).

COLUMBIA BASIN—BASIN-CENTERED GAS PLAY (503)

Introduction.—This hypothetical play underlies the widespread Miocene Columbia River Basalt Group in eastern Washington (Law, 1995a) (figs. 1, 4). The play area is nearly the same as that for the conventional Northwestern Columbia Plateau Gas play (501) (figs. 3, 12), and its geologic setting is described above under that play. The few wells that have been drilled through the Columbia River Basalt Group show that it has variable thickness that is commonly in excess of 5,000 ft (1,524 m). The sub-basalt rocks consist mainly of lower Tertiary fluvial and lacustrine rocks that were deposited in structurally complex basins; these rocks have highly variable thicknesses (e.g., Taylor and others, 1988; Evans and Johnson, 1989; Evans, 1994).

Interpretations of subsurface data from six widely spaced wells indicate the presence of a basin-centered gas accumulation. The well data show that the top of a thick, overpressured interval begins at depths ranging from 8,300 to 12,700 ft (2,530 to 3,872 m). Within the overpressured interval, large amounts of gas have been recovered on drill-stem tests. Although some water has also been recovered, most of the zones recovered gas with no water. The areal and spatial extent of the accumulation are imprecisely known because of insufficient deep drilling.

Reservoirs.—The potential reservoirs consist of Eocene arkosic fluvial sandstone bodies that are exposed on the northern margin of the play and consist of the Swauk, Chumstick, Roslyn, and Manastash Formations (Tabor and others, 1982, 1984; Taylor and others, 1988; Evans, 1994). The quality of these reservoirs is unknown. Surface exposures of the rocks on the play margins contain significant proportions of lithic fragments and micas (Frizzell, 1978; Taylor and others, 1988; Evans, 1994), and diagenetic alteration of these less-stable minerals is likely to produce low permeability. Porosity values ranging from 6 to 15 percent have been calculated from well logs (Lingley and Walsh, 1986). The thickness of the gas-bearing interval is at least 6,400 ft (1,951 m). The maximum thickness is unknown because the gas-bearing interval has not been entirely penetrated by drilling. Based on analysis of well logs, the depth of reservoirs within the play ranges from 8,300 (2,530 m) to more than 17,000 ft (5,183 m).

Source rocks.—The sources of gas are assumed to be the Eocene coal beds and carbonaceous rocks that are interbedded with reservoir rocks. Regional source-rock studies in Washington and Oregon indicate that nearly all organic matter in the region is a type-III kerogen, capable of generating mainly gas with little liquids (Law and others, 1984; Sidle and Richers, 1985; Core Laboratories, 1987a, 1987b). The level of thermal maturity within the gas-bearing interval ranges from 0.8 to more than 1.0 percent vitrinite reflectance (Lingley and Walsh, 1986; Core Laboratories, 1987a, 1987b), sufficient to generate gas.

Timing and migration.—Because gas is generated within or in close proximity to reservoirs in basin-centered gas accumulations, the temporal relationships between gas generation, migration, and development of a trap are not critical. It is not known when the reservoirs were charged with gas. It appears as though present-day temperatures are in or near equilibrium with measured levels of thermal maturity. Maximum burial occurred in the late Miocene, following eruption and deposition of the Columbia River Basalt Group.

Traps and seals.—See the discussion of the character of traps and seals needed for basin-centered gas accumulations in the introduction to this section.

Exploration status.—The play is unexplored. There are five wells that penetrate the gas accumulation; the last of these was drilled in 1988. Several production tests have been conducted, revealing gas flows at initial rates of as much as

3.1 MMCFD. Previous exploration activity in the play area has focused on more conventional structural plays. There is no indication that the region has been evaluated in the context of basin-centered gas accumulations.

Evaluation of resource potential.—Methodology developed by Schmoker (1995) was used to estimate resource potential of the Columbia Basin—Basin-Centered Gas play (503). Because of the hypothetical nature of the play, the Greater Green River Basin—Mesaverde play (3741), Wyoming, was used as an analog. Cell sizes of 80 and 160 acres were chosen. The number of cells under the two scenarios were 51,096 and 25,548; success ratios were 0.7 and 0.8, respectively. The mean EUR was 1,421 MMCFG. In addition, the estimation of liquid hydrocarbons utilized a ratio of 10 barrels per MMCFG. With this input data, the mean estimate of potential reserve additions is 12,200.1 BCFG and 122.0 MMB of natural gas liquids (table 5) (Law, 1995b).

DISCUSSION

Although Washington has no current petroleum production, the above play descriptions and associated resource estimates (tables 1–2, 4–6) indicate the State includes many possible petroleum systems with commercial potential. Because there is no petroleum production in Washington, there are fewer constraints on petroleum assessments than for developed regions and States. We reiterate that this relative lack of constraints makes it likely that other petroleum geologists may develop resource estimates somewhat different from ours.

The estimates of table 2 suggest that Washington has mean undiscovered technically recoverable conventional oil and gas resources of about 19 MMBO and 586 BCFG, respectively. We infer that the most significant resources are in the Northwestern Columbia Plateau Gas play (501), with a mean assessed resource of 235.10 BCFG and a 5 percent probability of 1.120 TCFG. Table 6 places Washington's estimated conventional oil and gas resources in perspective through comparison to other selected States and geologic provinces. Oregon, for example, has a similarly low inferred resource base, whereas Alaska's conventional oil and gas resources are estimated to be more than two orders of magnitude larger. Mean estimates of Washington's oil and gas conventional resources are just 0.07 percent and 0.23 percent, respectively, of the estimate for the total onshore United States (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995, table 1).

Table 4 shows that estimates of Washington's coal-bed gas resources (700 BCFG) are relatively small compared to those of the San Juan and Black Warrior basins (7.53 and 2.30 TCFG, respectively), where most national production of coal-bed gas is now carried out. Washington's estimated coal-bed gas resource forms about 1.4 percent of the

Table 5. Gas resources in continuous-type plays (excluding coal-bed gas plays).

[Comparison of U.S. Geological Survey estimates of undiscovered technically recoverable gas resources for the Columbia Basin—Basin-Centered Gas play (503) with that of continuous-type plays in selected geologic provinces. Information from Gautier and others (1995) and U.S. Geological Survey National Oil and Gas Resource Assessment Team (1995). Fractile values (F₉₅, F₅) are not additive. F₉₅ represents a 19 in 20 chance and F₅ represents a 1 in 20 chance of the occurrence of at least the amount tabulated]

Selected play or geologic province	Gas (trillion cubic feet)		
	F ₉₅	F ₅	Mean estimate
Columbia Basin—Basin-Centered Gas (503)	2.80	30.87	12.20
Uinta-Piceance basin (parts of Colorado and Utah)	11.55	23.38	16.74
San Juan basin, Colorado (parts of New Mexico, and Utah)	10.66	36.84	21.15
Southwestern Wyoming	55.95	213.51	119.30
Western Gulf (parts of Texas and Louisiana)	1.82	3.67	2.63
Appalachian basin (parts of New York, Pennsylvania, West Virginia, Ohio, Virginia, Kentucky, Tennessee, Georgia, Alabama)	43.12	83.66	61.21
TOTAL ESTIMATE, onshore United States*	219.36	416.55	308.08

*Total for onshore United States is not a sum of the selected areas listed on this table.

estimated cumulative coal-bed resource for the onshore lower 48 States (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995, table 5).

Table 5 shows that the resource estimate for Washington's Columbia Basin—Basin-Centered Gas play (503) is relatively similar to that of the petroliferous San Juan and Uinta-Piceance basins of the Rocky Mountain region, and represents about 4 percent of the total estimate for continuous-type gas accumulations (exclusive of coal-bed gas plays) in the onshore United States. Washington's Columbia Basin—Basin-Centered Gas play (503) resource is also estimated to be about 17 times larger than the State's estimated coal-bed gas resource (table 4) and 21 times larger than Washington's estimated conventional gas resource (tables 2, 6). Attanasi and others (1995, table 3) estimate that the threshold gas price for development of the Columbia Basin—Basin-Centered Gas play (503) resource is more than \$9 per MCF, which is significantly higher than the 1995 market price (about \$1.50 per MCF) and also greater than the estimated threshold price for a majority of other continuous-type gas plays recognized in the United States (Gautier and others, 1995). In contrast, the economic analysis of Donnelly and others (1995) suggests that this unconventional gas play may shortly become economic.

Regardless of economics, the Columbia Plateau region of eastern Washington holds the State's greatest potential for large fields that can have regional and national significance in meeting energy demands. Plays in western Washington will probably never provide a significant proportion of national or regional petroleum requirements; however, given the costs of transporting petroleum (including building and supporting infrastructure), it is possible that western Washington's petroleum resources can have local significance. For example, daily production at the Mist field (about 60 BCFG) in northwest Oregon (Bruer, 1980; Niem and others, 1994)

has been as high as 13 MMCF and provided as much as about 7 percent of Portland's gas supplies. Future hydrocarbon exploration in western Washington will no doubt concentrate on resources that would be used locally within the Pacific Northwest.

The lack of larger and richer petroleum systems in Washington can be attributed to its geologic history. Considerable Cenozoic sedimentary rock is present, having formed in a variety of strike-slip (Eocene) and forearc, intra-arc, and trench basin (Oligocene and younger) settings. Several strike-slip basins in California (such as the Los Angeles basin (table 6)), Venezuela, and elsewhere are very petroliferous, as are numerous forearc basins (such as the Sacramento basin (table 6) or Alaska's Cook Inlet)—so these basin types are not by nature poor habitats for petroleum resources.

Perhaps the most prominent limiting factor for Washington basins is the lack of good source rocks. In California's Neogene strike-slip basins, marine rocks of the Monterey Formation were deposited in many environments restricted from the influx of clastic sediments. In contrast, strata in Washington's Eocene strike-slip basins are predominantly nonmarine, rich in clastic sediments, and deposited at high sediment-accumulation rates (Johnson, 1985). These high rates probably precluded the origin of good organic-rich lacustrine facies, which provide the source beds for petroleum systems in other nonmarine basins (e.g., the Uinta-Piceance basin, table 6). Marine rocks (Eocene and younger) in the Grays Harbor and Tofino-Fuca basins of the Coast Range are also generally clastic rich and organic poor, again suggesting that sediment supply was a limiting factor on the development of good regional source rocks.

The quality of reservoir rocks is an additional limiting factor to development of significant petroleum accumulations in Washington, although not as important as the relative absence of good source rocks. Although many sandstone

Table 6. Conventional oil and gas resources.

[Comparison of U.S. Geological Survey estimates of undiscovered technically recoverable conventional oil and gas for Washington with those of other selected States and geologic provinces. Information from Gautier and others (1995) and U.S. Geological Survey National Oil and Gas Resource Assessment Team (1995)]

Selected State or geologic province	Crude oil (billion barrels)	Gas (trillion cubic feet)
	Mean estimate	Mean estimate
Washington	0.02	0.59
Oregon	0.00	0.32
Alaska	8.44	68.41
Sacramento basin, Calif.	<0.01	3.32
Los Angeles basin, Calif.	0.98	1.61
San Joaquin basin, Calif.	1.21	2.57
Uinta-Piceance basin, Colo. and Utah	0.21	4.54
Western Gulf Coast, Tex. and La.	2.29	68.09
TOTAL ESTIMATE, onshore United States*	30.25	258.69

*Total for onshore United States is not a sum of the selected areas listed on this table.

units lack significant porosity and permeability due to diagenetic alteration of abundant volcanic lithic debris (e.g., Galloway, 1974), there are also some excellent reservoirs, such as the Eocene sandstone beds used for gas storage in the Chetahis basin (Wurden and Ford, 1976). The best sandstone reservoirs are clearly the arkoses derived from crystalline source terranes to the east. These arkosic sandstones predominate in Eocene rocks (Frizzell, 1978; Johnson, 1985), which formed prior to latest Eocene initiation of the Cascade volcanic arc. Arkosic sandstones are also present, but in less abundance, in Neogene strata of southwest Washington (for example, parts of the Astoria and Montesano Formations; (fig. 2) sourced by the paleo-Columbia River drainage).

Suitable traps and seals are present for most plays. The most notable exception is the Western Washington Melange play (405), in which tectonic processes associated with subduction have probably disrupted and caused breaching in many potential reservoirs. Faulting along the west flank of the Cascade Range may have also compromised the integrity of sandstone and coal-bed reservoirs in the Southeastern Puget Lowland Gas play (402), the Puget Lowland Deep Gas play (403), and the Western Washington—Western Cascade Mountains play (451).

CONCLUSIONS

Washington hosts numerous possible petroleum systems, but there is no current petroleum production in the State. These possible petroleum systems are hosted by

sedimentary rocks deposited in Eocene strike-slip basins and late Eocene and younger intra-arc, forearc, and trench basins. Eight conventional petroleum plays, three coal-bed gas plays, and two continuous-type gas plays can be delineated in order to analyze and assess the resource potential of these possible petroleum systems. In these plays, the potential for significant petroleum accumulations is clearly greatest in the Columbia Plateau region of eastern Washington. Potential accumulations in western Washington are smaller but could have local economic significance. The absence of suitable source rock is probably the most important factor limiting development of large accumulations, although development of suitable reservoirs, traps, and seals also limits some plays. Play analysis indicates that Washington's petroleum resources are small and unlikely to have a significant impact on meeting the Nation's energy needs. Development of local petroleum resources, however, could be important in serving local economies.

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