114 T.C. No. 20

UNITED STATES TAX COURT

EXXON MOBIL CORPORATION AND AFFILIATED COMPANIES, f.k.a. EXXON CORPORATION AND AFFILIATED COMPANIES, Petitioners v. COMMISSIONER OF INTERNAL REVENUE, Respondent

Docket Nos. 18618-89, 18432-90. Filed May 3, 2000.

Held: For the years before the Court, $204 million (reflecting petitioners' 22-percent share of a total $928 million) in estimated dismantlement, removal, and restoration (DRR) costs relating to fieldwide oil production equipment and facilities located in the Prudhoe Bay oil field on the North Slope of Alaska is not sufficiently fixed and definite to be accruable under the all-events test of sec. 1.461-1(a)(2), Income Tax Regs.

Held, further, for the years before the Court, $24 million (reflecting petitioners' 22-percent share of a total $111 million) in estimated DRR costs relating specifically to oil wells and to well drilling sites located in the Prudhoe Bay oil field: (1) Is sufficiently fixed, definite, and reasonably determinable to satisfy the all-events accrual test of the accrual method of accounting; (2) is not accruable as a capital cost because such accrual would constitute

> a change in petitioners' method of accounting for such costs for which change respondent has not granted permission; and (3) is not accruable as a current ordinary and necessary business expense because such accrual would cause a distortion in petitioners' reporting of income.

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Richard L. Hunn, Robert M. Morrison, William G. Bissell, Carl D. Inskeep, Sandra K. Reid, Richard T. Cummings, and Richard D. Fultz, for respondent.

SWIFT, Judge: In these consolidated cases, respondent determined deficiencies in petitioners' Federal income taxes for the years 1979 through 1982 as follows:

Year	Deficiency
1979	$ 268,721,294
1980	2,898,174,073
1981	2,037,809,876
1982	1,599,495,218

After settlement of many issues and court decisions on three issues,[1] the primary issue remaining for decision is whether

[1] See Exxon Corp. v. Commissioner, 113 T.C. 338 (1999) (involving the creditability of the United Kingdom petroleum revenue tax); Exxon Corp. v. Commissioner, 102 T.C. 721 (1994) (involving percentage depletion); Exxon Corp. v. Commissioner, (continued...)

petitioners' attempted accrual, for 1979 through 1982, of its $204 million share of $928 million in total estimated dismantlement, removal, and restoration (DRR) costs relating to oil wells and to oil production equipment and facilities in the Prudhoe Bay oil field on the North Slope of Alaska (North Slope) would satisfy the all-events test of the accrual method of accounting. If, for the years in issue, the accrual of any of the estimated DRR costs would satisfy the all-events test of the accrual method of accounting, further issues are to be addressed relating to the amount and method of petitioners' claimed accrual thereof.[2]

Unless otherwise indicated, all section references are to the Internal Revenue Code in effect for the years in issue, and all Rule references are to the Tax Court Rules of Practice and Procedure.

FINDINGS OF FACT

The parties have stipulated numerous facts and the authenticity and admissibility of numerous exhibits. The stipulated facts are so found.

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[1](...continued)
T.C. Memo. 1999-247 (involving the accrual of deficiency interest).

[2] The issues in these consolidated cases have also been raised by petitioners in timely filed claims for refund for 1977 and 1978, which claims we understand to be still pending.

During the years in issue, petitioners constituted an affiliated group of more than 175 U.S. and 500 foreign subsidiary corporations. At the time the petitions were filed, petitioner Exxon Corp. was the common parent of the affiliated group, incorporated in New Jersey, with its principal places of business located in New York, New York, or Houston, Texas. Hereinafter, petitioners will be referred to simply as Exxon.[3]

The businesses in which Exxon was engaged primarily involved exploration for and production, refining, transportation, and sale of crude oil, natural gas, and other petroleum products. During the years in issue, Exxon owned a 22-percent interest in the Prudhoe Bay Unit, a partnership of international oil and gas companies that owned and operated oil and gas leases in the Prudhoe Bay oil field on the North Slope of Alaska.

Location of Prudhoe Bay Oil Field

The Prudhoe Bay oil field is located in an extremely remote area 250 miles above the Arctic Circle on the North Slope of Alaska. It is bounded by the Beaufort Sea on the north, the Arctic National Wildlife Refuge on the east, the Brooks Mountain Range on the south, and the Bering Sea on the west.

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[3] The parties appear to disagree as to Exxon’s principal place of business during the years in issue. If this question cannot be resolved by the parties by way of a post-opinion stipulation, it will be resolved in a Rule 155 hearing.

The surface of the Prudhoe Bay oil field consists of a flat, treeless, desert plain of approximately 69,000 square miles covered by a thin mat of vegetation and organic material called tundra. Beneath the tundra is a layer of permafrost that extends to a depth of 1,800 to 2,000 feet.

From mid-May through mid-September, the sun does not set on the North Slope. Summer temperatures may reach 80 degrees Fahrenheit. From June through September, when the tundra thaws to a depth of 12 to 18 inches, vehicular traffic on the tundra is prohibited unless authorized by permit and may be conducted only in specially designed vehicles called Rolligons.

During summer, the permafrost traps water on the tundra surface, and the North Slope becomes a wetlands with thousands of shallow lakes and abundant wildlife, including numerous migratory birds and animals.

In winter, North Slope temperatures fall to -70 degrees Fahrenheit, the tundra freezes, blizzards and whiteouts are common, and darkness prevails for much of the day. In late November, the sun dips below the horizon and does not reappear until mid-January.

In spite of harsh winter conditions, some work on the North Slope is better performed during winter because frozen tundra provides a better foundation for vehicular traffic than tundra that, during the summer, may not be passable.

In 1979, the U.S. Army Corps of Engineers designated the entire North Slope of Alaska as a protected wetlands. Ninety-nine percent of the tundra on the North Slope is treated as wetlands for regulatory purposes.

Even with the extensive oil wells and oil recovery equipment and facilities that were constructed in the Prudhoe Bay oil field and that will be described further below, the North Slope of Alaska accurately may be described and regarded as essentially undeveloped, as a habitat for fish, wildlife, and birds, with occasional subsistence use of the land by isolated Eskimo communities.

Physical access to the North Slope is limited. The Dalton Highway, a two-lane gravel road that traverses the Brooks Mountain Range, provides the only land access. The only all-water route to the North Slope follows the west coast of Alaska north through the Bering Sea, around Point Barrow, and east to Prudhoe Bay. Except during an ice thaw that lasts, on average, 6 weeks in late summer when the Arctic ice cap sufficiently recedes from the shoreline, marine vessels and barges cannot access Prudhoe Bay.

The North Slope has no significant local infrastructure. Fairbanks, located approximately 400 miles to the south and beyond the Brooks Mountain Range, is the nearest city to Prudhoe Bay. Anchorage is located 700 miles to the south. Other than the facilities and personnel associated with the Prudhoe Bay oil field and a few other producing oil fields, there are scattered throughout the North Slope just a few isolated Eskimo communities.

Because of its isolation and remoteness, labor, materials, equipment, and support services for major construction projects on the North Slope--in particular, for construction and installation of the Prudhoe Bay oil field equipment and facilities--must be imported, which significantly increases the costs of construction and of performing work on the North Slope. The oil companies' total $11 billion capital cost, in the 1970's and early 1980's, of installing and constructing the Prudhoe Bay oil field equipment and facilities was more than four times what the total cost would have been to install and construct a comparable oil field in the lower 48 States.

Alaska Oil and Gas Leases Relating to, and Discovery of, Oil Reserves in the Prudhoe Bay Oil Field

In 1959, by the Alaska Statehood Law of 1958, Pub. L. 85-508, 72 Stat. 339, the Federal Government authorized the new State of Alaska to select 103,350,000 acres of Federal lands within the boundaries of Alaska to become State lands. Alaska selected approximately 1.6 million acres on the North Slope between the Colville and Canning Rivers.

In 1964, the State of Alaska began to offer to oil and gas companies oil and gas exploration and development leases on its lands on the North Slope using the standard Alaska Competitive Oil and Gas Lease Form No. DL-1 (DL-1 Leases).

In 1964, 1965, 1967, and 1969, using the DL-1 Leases, with Exxon, Atlantic Richfield Co. (ARCO), British Petroleum (BP), and other oil and gas companies, Alaska entered into the particular oil and gas leases covering the portions of the Prudhoe Bay oil field that are involved in these cases. The terms of the DL-1 Leases extended for 10 years subject to being renewed by the oil companies as long thereafter as oil or gas is produced “in paying quantities”.

In December of 1967, Exxon and ARCO discovered a large oil and natural gas reservoir at an exploratory well that had been drilled on one of their jointly owned Prudhoe Bay leases. The reservoir, named “Sadlerochit”, after the Eskimo word for “area outside the mountains”, was and remains the largest oil and gas reservoir ever discovered on the North American Continent.

As of 1967, the reservoir was estimated to contain 23 billion barrels of oil in place and 42 trillion cubic feet of natural gas. Over its projected 30- to 50-year productive life, the Sadlerochit Reservoir was projected to produce from 13 to 14 billion barrels of liquid hydrocarbons, approximately 60 percent of the original oil in place.

Within the Prudhoe Bay field, the Sadlerochit Reservoir extends approximately 30 miles east to west and 13 miles north to south. It underlies approximately 111 Alaska oil and gas leases owned by various oil and gas companies.

Construction of Trans-Alaska Pipeline and Unitization of Prudhoe Bay Oil Field

In 1969, Exxon, ARCO, and BP announced plans to construct a 798-mile pipeline to transport oil recovered from the Prudhoe Bay oil field to the port of Valdez, Alaska, from which the oil would be shipped to the lower 48 States and to other destinations throughout the World. This pipeline came to be known as the Trans-Alaska Pipeline System (TAPS).

TAPS was constructed under rights-of-way granted in 1974 by the Federal Government and Alaska to a group of seven pipeline companies, including subsidiaries of Exxon, ARCO, and BP.

By early 1977 construction of TAPS was completed, and on June 20, 1977, oil production began from the wells located in the Prudhoe Bay oil field, and oil began flowing through TAPS to the port in Valdez, Alaska.

Production Facilities Constructed in the Prudhoe Bay Oil Field

Engineering obstacles that had to be overcome to construct the Prudhoe Bay oil wells and oil production facilities were enormous. The North Slope’s harsh conditions, fragile environment, and remote location presented unique challenges to the design, construction, and installation of the Prudhoe Bay oil field, the accomplishment of which constituted an engineering feat of breathtaking proportions.

Construction of the oil wells and of the related oil production facilities at Prudhoe Bay represents the largest oil development project in our country’s history. In addition to the oil wells, an extensive network of facilities was constructed to separate gas and water from crude oil recovered from the reservoir, to reinject separated natural gas and water into the reservoir in order to maintain reservoir pressure for enhanced oil recovery, to prepare recovered oil for transport through TAPS, to supply the necessary power and fuel requirements associated with all Prudhoe Bay operations, and to provide necessary support facilities.

The Prudhoe Bay oil field is laid out in a manner similar to an offshore oil field with centralized oil production facilities and isolated drilling locations. The oil well drilling equipment at the well sites rests on gravel pads called “well pads” from which multiple wells are drilled directionally underground into the oil reservoir. The six large production centers within the oil field are called “gathering centers” or “flow stations”.

Above-ground pipelines throughout the Prudhoe Bay oil field rest on vertical support members (VSM’s) and run from oil well drilling sites, to the production centers, and to TAPS. Pipelines within the Prudhoe Bay oil field are elevated on the VSM’s above the ground at a sufficient height so that the tundra would not melt and so that moose and other wildlife would be able to traverse the pipelines.

Due to the careful design, construction, and operation of the Prudhoe Bay oil field, the facilities and operations of the oil field have disturbed only 5,600 acres, or 2 percent, of the total land acreage at Prudhoe Bay.

In light of the costly and difficult construction conditions on the North Slope, the large industrial buildings and facilities at Prudhoe Bay (such as the flow stations and power plant), initially were constructed as large, modular buildings in plants near Bellingham and Seattle, Washington. The buildings, with the extensive equipment and facilities fully contained and installed therein, were then transported by special, oceangoing barges up the west coast of Canada through the Bering Sea to Prudhoe Bay where they were transported slowly over gravel roads to the installation sites in the Prudhoe Bay field.

To protect the North Slope tundra from thermal damage, the large plants and buildings constituting the oil production facilities at Prudhoe Bay were installed on pilings and gravel pads rising 4 to 6 feet above ground level. Once installed and in place at Prudhoe Bay, the modular segments of the large buildings were then joined together to form integrated facilities and buildings by connecting their structural components, piping, and electrical lines at interface points.

The oceangoing sealifts by which the equipment, buildings, and other facilities were transported by barge to Prudhoe Bay occurred in the 1970's and early 1980's.

By July of 1984, construction, transportation, and installation costs of the wells, the equipment, the buildings, the pipelines, and the other facilities installed at the Prudhoe Bay field reflected, as indicated, a total capital cost to the oil companies of approximately $11 billion. The facilities included 645 wells drilled on 37 drilling sites, 980 acres of pits, 800 miles of above-ground pipelines, 3 flow stations, 3 gathering centers, a central power station, a central compressor plant, a base operations center, electrical lines and associated poles, switchgear, transformers, and an offshore seawater treatment plant completed in 1983 and connected to the mainland by a gravel causeway.

Pump Station No. 1, the access or entry point from which oil flows out of the Prudhoe Bay oil production facilities and into TAPS, and a segment of the above-ground portion of TAPS lie within the geographical boundaries of the Prudhoe Bay oil field. Portions of the Endicott and Kuparuk pipelines, which transport crude oil from neighboring oil fields to Pump Station No. 1 for entry into TAPS, also traverse the Prudhoe Bay oil field. In many areas, the Endicott, Kuparuk, and Prudhoe Bay pipelines are physically indistinguishable and run alongside each other, supported above the tundra by the same VSM’s.

Unitization of Oil Company Interests in Prudhoe Bay Oil Field

Effective April 1, 1977, to save costs and to enhance operating efficiencies, Exxon and the other oil companies owning the oil exploration and production leases in the Prudhoe Bay field entered into a unitization or partnership agreement with the State of Alaska (Unit Agreement) under which they unitized their oil exploration and production leases into a single operating partnership, the Prudhoe Bay Unit (the PBU).

The Unit Agreement divided the Prudhoe Bay oil field into two operating areas--the Western Operating Area to be operated by BP and the Eastern Operating Area to be operated by ARCO.

Also, effective April 1, 1977, the PBU partners entered into the PBU Operating Agreement (Operating Agreement), which established how the PBU would be operated and how costs would be shared among Exxon and the other oil companies with ownership interests in the PBU. As indicated, under the Unit and Operating Agreements, Exxon's share of the total costs of constructing and operating the Prudhoe Bay oil field was approximately 22 percent.

When the PBU terminates, the individual leases to the oil companies will remain in force for at least 1 year or for as long as the lessee oil companies continue production of oil on the leases in paying quantities. The separate oil companies may take over and continue to operate wells and equipment on their leases after the Unit Agreement terminates. As permitted by paragraph 36 of the DL-1 Leases, the lessees may salvage any remaining equipment within a reasonable time but not less than 3 years after oil production terminates.

The Unit Agreement incorporates therein whatever oil company DRR obligations existed under the DL-1 Leases with the State of Alaska. It also stipulates that no well site may be abandoned until “final cleanup and revegetation, if required, is approved in writing” by the State. The Unit Agreement modified the original DL-1 Leases in certain respects not pertinent to the issues involved herein.

Production of Oil From Prudhoe Bay

From 1980 to 1987, oil production from the Prudhoe Bay field was at its peak, averaging approximately 1.5 million barrels per day, approximately 25 percent of total U.S. oil production. Since 1987, oil production from the Prudhoe Bay field has been declining. By 1997, more than 70 percent of the recoverable crude oil located in the Prudhoe Bay field had been recovered. Current projections by the PBU owners, the Alaska Department of Natural Resources, the Alaska Department of Revenue, and the North Slope Borough consistently forecast that oil production from the Prudhoe Bay field will end approximately in the year 2030, well after estimated production from other known oil reservoirs on the North Slope will have ended.

The PBU partners originally believed that they might be able to recover and to market natural gas reserves located in the Prudhoe Bay field. To date, however, studies conducted by the PBU partners and by State and Federal agencies indicate that natural gas recovery from Prudhoe Bay will not be economically viable given the projected low price of natural gas relative to the high cost of recovering, producing, and transporting natural gas from the Prudhoe Bay field to world markets. In 1987, Exxon “debooked” (removed from “proved undeveloped” to “uneconomic”) the natural gas reserves in the Prudhoe Bay field. In 1988, the U.S. Department of Energy (DOE) agreed with that decision and reduced its estimate of North Slope natural gas reserves by 24.6 trillion cubic feet.

The extensive Prudhoe Bay oil field production facilities and the TAPS pipeline from Prudhoe Bay to Valdez, Alaska, were designed for the recovery, processing, and transportation of crude oil, not natural gas, and it is not anticipated that any significant portion of the Prudhoe Bay oil field production facilities and the TAPS pipeline would be usable or modifiable for the eventual recovery and transportation of natural gas from the Prudhoe Bay field should recovery of the Prudhoe Bay natural gas someday become economically viable. That is, it is anticipated that separate, new wells, processing, and transportation facilities would have to be constructed for the recovery from the Prudhoe Bay field of natural gas, if recovery of such natural gas someday would become profitable.

<u>Terms of DL-1 Leases Relating to Exxon's DRR Obligations</u>

The particular provisions of the DL-1 Leases (under which Exxon and the other oil companies conducted oil exploration and recovery activities in the Prudhoe Bay field) that apply to DRR obligations of Exxon and of the other oil companies upon termination of oil production in the Prudhoe Bay oil field are vague and general.

The principal language of the DL-1 Leases that describes what is to happen--upon termination of oil production at Prudhoe Bay--to the extensive oil production equipment and facilities located in the Prudhoe Bay field is found in paragraph 36, which reads oddly and ambiguously in terms of "rights" and "privileges" of the oil companies (not in terms of DRR "duties or obligations") as follows:

> <u>RIGHTS</u> ON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of said lands, * * * <u>[Exxon] shall have the privilege</u> at any time within a period of six months thereafter, or such extension thereof as may be granted * * * [by Alaska], <u>of removing</u> from said land or portion thereof <u>all machinery, equipment, tools, and materials</u> other than improvements needed for producing wells. <u>Any materials, tools, appliances, machinery, structures, and equipment subject to removal as above provided which are allowed to remain on said land or portion thereof shall become the property of * * * [Alaska]</u> upon expiration of such period; <u>provided, that * * * [Exxon] shall remove any and all of such properties when so directed by * * * [Alaska]</u>. <u>Subject to the foregoing, * * * [Exxon]</u>

> shall deliver up said lands or such portion or portions thereof in good order and condition. [Emphasis added.]

Language in paragraph 20 of the DL-1 Leases--pertaining generally to due diligence and to prevention of waste in the conduct of activities at Prudhoe Bay--does contain specific reference to Exxon's (and to the other oil companies') obligations to plug wells upon termination of oil production at the well sites. That language also makes general reference to Alaska regulations "relating to the matters covered by this paragraph" (namely, to due diligence and to waste). The language of paragraph 20, however, provides neither a description of DRR work that Exxon is or will be obligated to perform on leased property not associated with well sites nor specific reference to any Alaska regulations pertaining to broader fieldwide DRR obligations of the oil companies. Paragraph 20 provides, in part, as follows:

> DILIGENCE; PREVENTION OF WASTE. * * * [Exxon] * * * shall plug securely in an approved manner any well before abandoning it; * * * and shall abide by and conform to valid applicable rules and regulations of the Alaska Oil and Gas Conservation Commission and the regulations of * * * [Alaska] relating to the matters covered by this paragraph in effect on the effective date hereof or hereafter in effect if not inconsistent with any specific provisions of this lease. [Emphasis added.]

Language in paragraph 31 of the DL-1 Leases provides for assignment of the leases, or of undivided interests in the leases, subject to the State's approval. Language in paragraphs 4, 7, 8, and 28 provides for suspension of operations without the leases expiring.

Language in paragraph 33 of the DL-1 Leases provides that Exxon (and the other oil companies), should it so choose, may abandon or surrender its interests in the leases to the State, provided it--

> [places] all wells on the surrendered land * * * in condition satisfactory to * * * [Alaska] for suspension or abandonment; thereupon, * * * [Exxon] shall be released from all other obligations accrued or to accrue under this lease with respect to the surrendered lands * * *. [Emphasis added.]

Alaska Law and Regulations Relating to Exxon’s DRR Obligations in Prudhoe Bay

In 1959, the new State of Alaska Constitution provided for “development, and conservation of all natural resources * * * for the maximum benefit of its people.” Alaska Const. art. VIII, sec. 2. Alaska’s land management policies generally allow development of Alaska’s natural resources on condition that the environment be restored to the maximum reasonable extent upon completion of operations.

In 1967, the Alaska Oil and Gas Conservation Commission (AOGCC) issued regulations relating to plugging and abandonment of oil wells and to cleanup of oil well sites. See Alaska Admin. Code tit. 11, secs. 2101-2108 (effective Sept. 1967), later at Alaska Admin. Code tit. 11, secs. 22.100-22.110 (1973), and at

Alaska Admin. Code tit. 20, secs. 25.105-25.170 (1980). These regulations are written only in terms of "plugging" the wells and cleaning up "loose debris" and restoring the well sites to a "generally level condition." The AOGCC regulations do not set forth or describe either specific or general DRR obligations of oil companies relating to the extensive Prudhoe Bay oil processing facilities not located at well drilling sites.

In 1972, in anticipation of oil production at Prudhoe Bay, a joint Federal-State commission was established to study Alaska land use issues. In 1979, the commission stated in its final report that development activities in the Arctic "should not lead to irreversible consequences" and that "areas impacted should be capable of restoration to a natural state upon the completion of development activities." (Emphasis added.)

TAPS Right-Of-Way Provisions

In contrast to the generally vague language of the DL-1 Leases relating to oil company DRR obligations in the Prudhoe Bay oil field, language in the TAPS right-of-way provisions relating to DRR obligations of the oil companies which constructed and which operate TAPS is more specific. As explained, TAPS was constructed, and operates today, under lease rights-of-way granted in 1974 by the Federal and Alaska State Governments to a group of seven pipeline companies, which include subsidiaries of Exxon, ARCO, and BP. The Federal and Alaska right-of-way agreements for TAPS contain express language and provisions relating to oil company DRR obligations that specifically require the oil companies, upon termination of their use of the TAPS rights-of-way, to remove the facilities, improvements, and equipment. The Federal right-of-way agreements for TAPS state:

> Stipulations for the Agreement and Grant of Right-of-Way for the Trans-Alaska Pipeline
>
> 1.10. Completion of Use
>
> > 1.10.1. * * * [the oil companies] <u>shall promptly remove all improvements and equipment</u>, except as otherwise approved in writing by the Authorized Officer, and <u>shall restore the land</u> to a condition that is satisfactory to the Authorized Officer <u>or</u> at the option of * * * [the oil companies] <u>pay the cost of such removal and restoration</u>. * * * [Emphasis added.]

The State of Alaska right-of-way agreements for TAPS contain virtually the same language explicitly requiring the oil companies, upon shutting TAPS down, to perform or to pay for the DRR work associated with dismantling and removing the pipeline and restoring the land.

<u>DRR Liabilities Recognized for TAPS Rate Making Purposes</u>

As stated, the Federal right-of-way agreements and the permits relating to TAPS expressly require DRR work to be completed by the oil companies upon termination of pipeline operations.

Also, in setting transportation rates for TAPS and other pipelines on the North Slope, the Federal Energy Regulatory Commission (FERC) has permitted owners of the pipelines to treat estimated DRR costs as capital costs of constructing the pipelines and therefore as costs that are recoverable ratably over the life of the pipelines through rate charges for transporting oil through TAPS and the other pipelines.

PBU Financial Statements and PBU Tax Reporting Relating to Estimated DRR Costs at Prudhoe Bay

For all relevant years and all items (including DRR costs), the financial books and records and the Federal partnership income tax returns of the PBU were prepared on the accrual method of accounting.

From formation of the PBU partnership through the years in issue, on the financial books and records and on the Federal income tax returns of the PBU partnership, DRR costs were accrued utilizing the all-events test of the accrual method of accounting. At the time, it was understood generally within the oil industry that DRR costs could not be accrued for Federal income tax purposes until the related DRR work was actually performed. This understanding was consistent with and followed respondent’s then-published position that DRR work had to be performed before the related DRR costs for tax purposes could be accrued under the all-events test. See Rev. Rul. 80-182, 1980-2 C.B. 167.

Accordingly, for the years in issue, the PBU partnership accrued ordinary business expense deductions relating to DRR costs in the years in which the related DRR work was performed.

On the PBU partnership Federal income tax returns for the years in issue (1979-82), with respect to estimated future Prudhoe Bay DRR costs associated with projected DRR work to be performed in subsequent years upon termination of oil production at Prudhoe Bay, no accrual was claimed for an increase to a capital liability account, for an increase in the depreciable tax basis of capital assets at the Prudhoe Bay field, nor for ordinary and necessary business expenses.

During the years in issue, a PBU-sponsored DRR cost study relating to the Prudhoe Bay field was not completed.

On its 1979 and 1980 partnership Federal income tax returns, the PBU elected to compute depreciation on its depreciable assets placed in service in those years under the class life asset depreciation range (ADR) system of section 1.167(a)-11, Income Tax Regs. For those same years, PBU elected under section 167(f) to reduce the amount taken into account as salvage value by an amount not exceeding 10 percent of the basis of property depreciated under the ADR system. In making this election, the PBU claimed that the gross salvage value did not exceed 10 percent of the unadjusted basis of the facilities. This election caused the salvage value of each ADR vintage account to be reduced to zero. For 1981 and 1982, the PBU depreciated assets placed in service in 1981 and 1982 under the Accelerated Cost Recovery System (ACRS) of section 168.

Exxon’s Financial Reporting Relating to Estimated Prudhoe Bay DRR Costs

In 1977, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies” (FAS 19),[4] which required oil and gas companies, for financial income statement reporting purposes, to take estimated future DRR costs into account in determining amortization and depreciation rates. For financial accounting purposes, oil and gas companies have estimated such costs in a variety of ways. Where estimates of DRR costs exceed estimated salvage value, oil and gas companies, including Exxon, have reported and claimed, for financial income statement reporting purposes, depreciation

[4] Paragraph 37 of FAS 19 provides with regard to fixed DRR obligations the following income statement accounting for DRR:

> Estimated dismantlement, restoration, and abandonment costs and estimated residual salvage values shall be taken into account in determining amortization and depreciation rates.

FAS 19 does not address the balance sheet accounting for DRR. In a February 1996 Exposure Draft entitled “Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets”, which would include onshore and offshore oil and gas production facilities, the FASB recommended that oil and gas companies, for financial reporting purposes, fully accrue estimated future DRR costs that represent fixed obligations in the year the obligations first arise, capitalize such costs into the bases of the related assets, and recover the costs through depreciation deductions over the productive lives of the assets.

expenses for estimated future DRR costs (including those relating to the Prudhoe Bay oil field) over the entire life of an oil field using the units-of-production method.

Oil and gas companies, including Exxon, typically review and revise their estimates and depreciation rates relating to estimated future DRR costs throughout the life of a field. Their financial income statements incorporate and reflect changes in DRR cost estimates relating to changes in technology, inflation, labor, equipment, and material rates. When new facilities are installed, oil and gas companies reflect additional estimated DRR costs relating to the new facilities in their financial income statements as additional depreciation expenses.

FAS 19 does not state that estimated future DRR costs should be reflected as a fixed capital liability on a company's financial balance sheets.

During the years in issue, consistent with FAS 19, Bulletin 61 of Exxon's financial accounting manual, "Accounting for Cost of Plant Removal and Site Restoration" relating to the accrual of DRR costs, provided as follows:

> Annual accruals [for future DRR] are to be provided only if <u>both</u> of the following conditions are met:
>
> 1) The work must be required as the result of local laws or regulations, or as part of a contractual agreement.
>
> 2) The nature of the work is such that it is possible to estimate its cost. Thus, the law or

> agreement must specify the work to be performed or the conditions to be met.

For the years in issue, Exxon, like most other oil and gas companies, did not recognize on its financial balance sheet statements estimated future DRR costs as a fixed liability. Rather, Exxon disclosed estimated future DRR costs in a note to its financial statements and, as required by FAS 19, reflected and claimed estimated future DRR costs relating to Prudhoe Bay and to its other oil and gas facilities in its annual depreciation calculations on its financial income statements.

As indicated, during the years in issue, no PBU partnership-wide study was made of estimated future Prudhoe Bay DRR costs. Rather, each oil company, including Exxon, with a working interest in the PBU partnership generally developed its own estimate of future Prudhoe Bay DRR costs.

Set forth in the schedule below for 1977 through 1988 are the amounts of its share of total future Prudhoe Bay DRR costs that, at the end of each year, were estimated by Exxon. The amounts vary because of differences in methodology and assumptions that were used from year to year to estimate total future DRR costs.

Year	Exxon's Estimated Future Total Prudhoe Bay DRR Costs (Millions)
1977	$215
1978	215
1979	228
1980	122
1981	162
1982	180
1983	247
1984	300
1985	300
1986	333
1987	209
1988	209

As indicated, in its financial income statements for each year, Exxon included a depreciation expense item relating to its share of the above estimated future Prudhoe Bay DRR costs. On Exxon's financial income statements for each year, the amount of the depreciation expense item reported for estimated Prudhoe Bay DRR costs was calculated roughly on the basis of the above estimates of total future Prudhoe Bay DRR costs and on the basis of the units of oil production that occurred in each year relative to Exxon's estimates of total oil recovery that would occur at Prudhoe Bay over the projected life of the field, reflecting Exxon's 22-percent interest in the PBU.

Following FAS 19 and oil industry practice, however, on its annual financial balance sheet statements Exxon did not accrue as a fixed capital liability or cost any of the above estimated Prudhoe Bay DRR costs. Rather, on such yearend financial balance sheet statements, the amount of the annual depreciation expense relating to estimated future Prudhoe Bay DRR costs, which was reflected on Exxon's income statements as an item of depreciation and charged to earnings, was credited to a "reserve" liability account.

During the years in issue, for financial income statement and balance sheet reporting purposes, Exxon's practice for the financial reporting of estimated future DRR costs was the same as that followed by a majority of oil and gas companies.

Set forth in the section below (infra p. 30), is a schedule setting forth, among other things, the amount of estimated future PBU DRR costs that Exxon, in its financial income statements for each year, accrued as a depreciation expense and added to a liability reserve account.

Exxon's Federal Corporation Income Tax Returns and Now Proposed Tax Treatment of Estimated DRR Costs

In preparing and filing its Federal corporation income tax returns for the years in issue, Exxon used the accrual method of accounting, and Exxon has consistently used the all-events test as the standard for determining when its liabilities accrue under the accrual method of accounting.

On its consolidated Federal corporation income tax returns for the years in issue, Exxon accrued costs relating to its worldwide DRR obligations on the accrual method of accounting as its tax return preparers then understood the application to DRR costs of the all-events test of the accrual method of accounting.

That is, DRR costs, for Federal income tax return purposes, were accrued only when the related DRR work was performed and then as current business expenses. As explained and as reflected in Rev. Rul. 80-182, 1980-2 C.B. 167, this was consistent with respondent's interpretation of how the all-events test of the accrual method of accounting applied to DRR costs.

Set forth below for each of the years 1977 through 1982 is a schedule that reflects the amount of estimated Prudhoe Bay DRR costs indicated: (1) On Exxon's financial balance sheet statements (as explained, estimated DRR costs were accrued on Exxon's financial balance sheet statements not as a fixed liability cost but only in a footnote as a reserved liability); (2) on Exxon's financial income statements (as explained, estimated future DRR costs were accrued on Exxon's income statements as a depreciation expense based on units of oil production that occurred in each year); (3) on Exxon's Federal income tax returns, as filed with respondent (as explained, on Exxon's income tax returns DRR costs were not accrued until DRR work was performed and then as current business expenses); and (4) as now claimed by Exxon for Federal income tax purposes, namely, in the year Prudhoe Bay oil wells and the related equipment, facilities, and buildings were constructed, total estimated future Prudhoe Bay DRR costs would be capitalized and for each year related accelerated depreciation, investment tax credits, and intangible drilling costs, or, alternatively, current business expense deductions would be claimed therefor.

Exxon's Accrual of Estimated Future PBU DRR Costs				
	On Financial Statements		Tax Treatment	
For	On Balance Sheets As Fixed Liability	On Income Statements As Depreciation Expense & On Balance Sheets As Addition To Reserved Liability (Millions)	Current Expense On Tax Returns As Filed With Respondent (Thousands)	Would Now Capitalize & Claim Depreciation, ITC, & IDC, Or Current Expense (Millions)
1977	---	$2.5	-0-	$ 6.9
1978	---	4.2	$15,040	11.4
1979	---	6.1	-0-	11.8
1980	---	4.1	-0-	12.4
1981	---	5.2	-0-	13.7
1982	---	6.0	-0-	18.8

In the 1980's, a Tax Court decision allowed, for Federal income tax purposes, the accrual of estimated future strip-mining land reclamation costs relating to underground mines. See Ohio River Collieries Co. v. Commissioner, 77 T.C. 1369 (1981). As a result, in the late 1980's, the PBU and the partners in PBU including Exxon raised in these pending cases with respondent via timely claims for refund the DRR cost accrual issue relating to estimated Prudhoe Bay DRR costs, as well as the accrual of estimated DRR costs for other projects throughout the world.

As a result of such claims, with regard to oil company estimated DRR costs relating to underground mines, oil shale projects, and TAPS, respondent has allowed Exxon and other oil companies the tax accrual of estimated DRR costs.

For the years in issue, with regard to estimated DRR costs relating to foreign offshore oil drilling platforms and to Exxon’s oil wells located in the lower 48 States (as well as those relating to the Prudhoe Bay oil field), respondent continues to disallow the accrual of estimated DRR costs. With regard to the accrual of DRR costs relating to foreign offshore oil drilling platforms and to Exxon’s oil wells located in the lower 48 States, Exxon has withdrawn its claims for refund with regard thereto.

In the referred-to claims for refund, the PBU and Exxon have raised the issue of whether they may accrue estimated DRR expenses relating to Prudhoe Bay beginning in 1977, the first year of the PBU partnership’s existence, and Exxon has pending refund claims on the issue beginning with each year of the PBU partnership.

As explained, Exxon’s primary position in these cases is that estimated DRR costs relating to the oil-producing equipment and facilities located in the Prudhoe Bay field should be accruable, in the year such equipment and facilities are constructed and installed, as capital costs of the facilities and depreciated under the relevant tax depreciation system (for the years in issue--ADR and ACRS). Further, with regard to estimated DRR costs that are capitalized and that relate specifically to oil wells and to cleanup of oil well sites, Exxon claims that investment tax credits under section 38 and intangible drilling costs under section 263(c) should be allowed.

Alternatively, in the year the oil field equipment and facilities were constructed and installed, Exxon claims that estimated Prudhoe Bay DRR costs should be accruable under section 162 as ordinary and necessary business expense deductions.

Exxon’s Estimates of Future PBU DRR Costs

Exxon’s experts have made elaborate and detailed projections with regard to future DRR activity that may be undertaken in the Prudhoe Bay field and to estimated DRR costs that may be incurred with respect thereto. In doing so, they claim that all facilities in Prudhoe Bay other than the Seawater Treatment Plant will be dismantled beginning in the year 2031 and that it will take 6 years to dismantle and remove the facilities and equipment from the North Slope of Alaska.

Exxon estimates that a total of $928 million in DRR costs relating to the Prudhoe Bay oil-producing facilities will be incurred by the PBU partnership, and Exxon calculates that its share thereof will be approximately $204 million.

OPINION

Accrual of DRR Costs Under the All-Events Test of Section 461

For Federal income tax purposes during the years in issue, an accrual basis taxpayer generally may accrue costs not yet paid in the year in which the costs satisfy the two-pronged all-events test of the accrual method of tax accounting; i.e., in the year in which all the events occur that establish the fact of the taxpayer's liability for the costs and in which the amount of the liability can be determined with reasonable accuracy. See United States v. General Dynamics Corp., 481 U.S. 239, 243-244 (1987); United States v. Hughes Properties, Inc., 476 U.S. 593, 600 (1986); United States v. Anderson, 269 U.S. 422, 437-438 (1926); sec. 1.446-1(c)(1)(ii), Income Tax Regs.

As the Supreme Court has explained:

> It is fundamental to the "all events" test that, although expenses may be deductible before they have become due and payable, liability must first be firmly established. This is consistent with our prior holdings that a taxpayer may not deduct a liability that is contingent * * *. [United States v. General Dynamics Corp., supra at 243.]

The all-events test also applies under section 1012 to the accrual into the tax bases of capital assets of estimated future capital costs. See Denver & Rio Grande W. R.R. v. United States, 205 Ct. Cl. 597, 505 F.2d 1266 (1974); La Rue v. Commissioner, 90 T.C. 465 (1988); Seaboard Coffee Serv., Inc. v. Commissioner, 71 T.C. 465, 476 (1978); Lemery v. Commissioner, 52 T.C. 367, 377-378 (1969), affd. per curiam 451 F.2d 173 (9th Cir. 1971); Gibson Prods. Co. v. United States, 460 F. Supp. 1109, 1115 (N.D. Tex. 1978), affd. 637 F.2d 1041 (5th Cir. 1981); sec. 1.461-1(a)(2), Income Tax Regs. Herein, respondent disputes whether Exxon’s attempted accrual of estimated Prudhoe Bay DRR costs would satisfy either prong of the all-events test.

The first prong of the all-events test looks only to whether the taxpayer’s fact of liability for the costs in question has been established. This test may be satisfied even if it is not known when or to whom costs will be paid. See United States v. Hughes Properties, Inc., supra at 604; Valero Energy Corp. & Subs. v. Commissioner, 78 F.3d 909, 915 (5th Cir. 1996), affg. T.C. Memo. 1994-132. A liability can be fixed even if there are procedural or ministerial steps that still have to occur before payment. Accrual should be deferred if the occurrence of those steps is sufficiently uncertain that they render the taxpayer’s liability contingent. See, e.g., Continental Tie & Lumber Co. v. United States, 286 U.S. 290 (1932); United States v. Anderson, supra.

The mere speculative possibility that some future event will release the taxpayer from its liability does not prevent accrual. See, e.g., United States v. Hughes Properties, Inc., supra at 601-602, 606.

Exxon argues that the combination of the DL-1 Lease provisions, Alaska law, regulations, and oil industry practice, as of the end of each of the years 1979 through 1982, establish the fixed and definite nature of Exxon’s future Prudhoe Bay DRR obligations regarding the entire Prudhoe Bay oil field. The extent of the DRR obligations to which Exxon contends the PBU and the other oil companies became subject upon construction of the Prudhoe Bay oil wells and oil production facilities is summarized briefly by one of Exxon’s experts, as follows:

> PBU will have to plug all wells, close all reserve and containment pits, remove all above-ground pipelines and electrical lines, and remove all other structures, such as modular flow stations and gathering centers. The PBU Partners will have to dismantle, transport to barges, and transport off the North Slope the modules, pipelines, and electrical distribution systems, and leave the land in a clean and generally level condition. It is expected that Exxon and its PBU Partners will perform these DRR obligations around the year 2030.

In comparing the language of the right-of-way agreements relating to TAPS and to the other North Slope pipelines involved in the FERC rate-making proceedings, on the one hand, to the language of the DL-1 Lease agreements, on the other, Exxon’s experts sense a common denominator or “idea” in the language of both sets of right-of-way agreements (namely, that removal of the equipment and related DRR work is “required” in each instance).

We note simply that specific language relating to oil company DRR obligations is found in the TAPS right-of-way agreements, but, as we have explained, is not found in the language and provisions of the DL-1 Leases that relate to fieldwide oil production facilities at Prudhoe Bay.

Neither the language of paragraph 36 nor the language of paragraph 20 of the DL-1 Leases reflects fieldwide facility and equipment dismantlement, removal, or restoration obligations. As we have explained, paragraph 36 is written in terms of a “privilege” of the oil companies to remove equipment if they so choose or of an “option” of Alaska to have the equipment removed if it so elects. Paragraph 20 refers only generally to waste and due diligence, to preservation of the land, and to plugging abandoned wells. Fixed obligations to dismantle, remove, and restore the Prudhoe Bay fieldwide facilities and equipment are not reflected in the language of paragraph 20.

Further, as we have found, and contrary to Exxon’s experts, AOGCC regulations in effect during the years in issue relate only to plugging, abandonment, and cleanup of oil well sites and do not apply to, and do not establish, DRR obligations of the PBU or of the oil companies to the extensive Prudhoe Bay oil field equipment and facilities not located at oil well sites.

Again, we note that the right-of-way leases relating to TAPS and the regulations relating to oil well drilling sites reflect express language that imposes DRR obligations on the oil companies. The DL-1 Leases and the Alaska regulations, however, contain no such express language imposing fixed and definite DRR obligations on the oil companies relating to fieldwide production facilities located in the Prudhoe Bay oil field.

We believe the differences in language relating to DRR obligations are significant for purposes of the all-events test of the accrual method of accounting. We believe that specific DRR obligations relating to fieldwide oil production facilities could have been reflected in the DL-1 Leases or in the Alaska regulations were such obligations intended. Specific DRR language was used in the TAPS right-of-way provisions. No adequate explanation has been provided as to why specific language relating to DRR obligations of the PBU and of the oil companies relating to fieldwide DRR was not set forth either in the DL-1 Leases or in the Alaska regulations, other than that such DRR obligations with regard thereto, as of the years in issue, were not established.

As the current Commissioner of the Department of Natural Resources for the State of Alaska acknowledged in his trial testimony herein, as late as 1997 no Alaska regulations specifically covered Prudhoe Bay fieldwide DRR obligations of the oil companies. He testified as follows:

> <u>Question.</u> So in June of 1994, your Deputy Commissioner said there was no established policy on DRR and in June of 1997 you said there is no fixed policy on DRR but now you are claiming on the witness stand that there is, is that correct?
>
> <u>Answer.</u> I'm not claiming there is a policy. I am claiming there's an expectation. We do not have a policy written in regulation about lease closure and how we go about lease closure. This has been a general concern of the industry that goes well beyond this case, and the purpose of my memorandum to the staff was to continue work that had begun earlier on such a policy.
>
> However, we have certainly in the lease and, I think, in a variety of other arenas stated our expectations of the industry, and I think those expectations show very high standards in terms of environmental cleanup.
>
> <u>Question.</u> But those expectations are not stated in any regulation or official ruling, is that correct?
>
> <u>Answer.</u> That is correct.

The 1979 joint Federal-State commission that studied Alaska land use issues and that concluded that development activities in the North Slope should not irreversibly damage the environment and that the environment should be "capable" of restoration upon completion of development activities imposed no fixed and definite DRR obligations on Exxon. An "expectation" of and the "capability" of restoration do not necessarily <u>require</u> restoration.

Exxon placed in evidence the extensive history, during the 1960's through the present, of the State of Alaska’s supervision of oil company abandonment and cleanup operations of numerous North Slope exploratory well sites. Exxon emphasizes and argues that such history and practice and the AOGCC regulations (relating to abandonment of wells and to cleanup of well sites) together establish affirmative DRR obligations of the oil companies for all of the massive equipment and facilities located in the entire Prudhoe Bay oil field. One of Exxon’s experts states in his report as follows:

> The AOGCC’s record of strict enforcement of cleanup requirements [for well locations] over the last thirty-one years * * * evidences the State’s commitment to having its <u>lands</u> returned in good order and condition * * *. [Emphasis added.]

We reject the equation, if that is what is intended by Exxon’s expert, between well sites and the balance of the “lands” constituting the Prudhoe Bay oil field.

Recognizing the dispute between Exxon and respondent over alleged differences between well sites and the balance of the Prudhoe Bay oil field, Exxon’s expert comments as follows:

> It is not necessary to resolve the issue of what constitutes a “location” to understand that the cleanup requirements of paragraph 20, the AOGCC regulations, and the consistent, virtually uniform pattern of enforcement over many years, collectively illustrate

> the type of standards which will be applicable to final cleanup at the PBU. Far from the AOGCC regulations being somehow distinct and inapplicable, there is every reason to conclude that the State of Alaska will enforce DRR obligations under State leases consistent with the approach applied under these regulations.

To the contrary, “expectations” or reasonable and probable “predictions” on the part of Alaska government officials and Exxon’s experts regarding what eventually may be required from the oil companies in the way of Prudhoe Bay fieldwide DRR do not provide a sufficiently fixed and definite basis on which to base the tax accruals sought herein. During the years before us, such expectations and predictions simply do not satisfy the all-events test of section 461. They do not rise to the level of fixed and definite legal obligations.

The fact that Exxon annually on its financial income statements accrued a depreciation deduction for DRR costs based on units of oil produced each year does suggest, as Exxon argues, that Exxon’s management considered some accrual of estimated Prudhoe Bay DRR costs appropriate and consistent with Exxon’s financial accounting policies and with generally accepted financial accounting principles. As explained, under FAS 19 oil companies are required to accrue as an expense future DRR costs where the company is under an existing obligation to incur such costs and where such future DRR costs can be estimated with reasonable accuracy.

The rules of financial accounting and a company’s financial treatment of such costs, however, whether correct or incorrect thereunder are not controlling for Federal income tax purposes. See Thor Power Tool Co. v. Commissioner, 439 U.S. 522, 540 (1979). We also note that Exxon, for financial reporting purposes, did not on its financial balance sheets (as distinguished from its financial income statements) accrue any fixed liability relating to estimated DRR obligations at Prudhoe Bay.

Exxon argues strenuously that respondent’s position, under which no tax accrual would be allowed for estimated future Prudhoe Bay DRR costs, produces a fundamental and gross mismatch of Exxon’s income and expenses relating to Prudhoe Bay oil recovery. Under the matching principle of Federal income tax accounting, however, only those obligations are to be recognized that are properly accruable (i.e., that satisfy the all-events test). To allow estimated costs of obligations that do not satisfy the all-events accrual test (such as the majority of the estimated DRR costs involved herein) to be accrued and to offset current income is not part of the matching principle.

Further, Alaska’s general policy under its constitution for management of Alaska lands (to permit development while at the same time insisting that the environment be preserved or, if necessary, restored to the fullest reasonable extent) does not establish any specific oil company DRR obligations with regard to

Prudhoe Bay that may be legally recognized for Federal income tax purposes.

DRR Obligations Relating Specifically to
Well Plugging and to Well-Site Cleanup

Contrary to our holding regarding fieldwide Prudhoe Bay DRR, we believe Exxon’s Prudhoe Bay DRR obligations relating specifically to oil wells and to oil well sites are clearly set forth and established in the provisions of the DL-1 Leases and satisfy the first prong of the all-events test of the accrual method of accounting. Paragraph 20 expressly states that upon closing down wells, Exxon is to plug the wells and abide by Alaska regulations relating to such plugging. For the years in issue, Alaska regulations similarly required oil companies to plug and to clean up well drilling sites.

Respondent argues that the filing of a “notice of abandonment” of the wells constitutes a condition precedent to the recognition of any firm oil company DRR obligations. Also, respondent argues that DRR technology and Alaska regulations regarding well plugging and well-site cleanup may be changed by the time the wells in the Prudhoe Bay field are to be plugged by the oil companies, making all DRR work that the oil companies might have to perform in Prudhoe Bay indefinite and speculative. We disagree. We regard the notice of abandonment provision of the DL-1 Leases as ministerial and perfunctory, certainly not a condition precedent to DRR obligations relating to the wells which obligations came into existence when the wells were drilled. As Exxon on brief explains:

> it is preposterous to think that Exxon could avoid having to plug wells simply by refusing to file a notice of abandonment. * * * Filing the notice is just a step in <u>performing</u> the well plugging obligation already imposed by Paragraph 20 of the lease.

Further, in the oil industry, oil well plugging and site cleanup relating thereto are common events. Although variations in plugging procedures may occur, we believe sufficient oil industry experience and practice are established with regard to the frequent procedure of well plugging and well-site cleanup that possible changes in technology and Alaska regulations do not render Exxon's Prudhoe Bay DRR obligations with regard thereto indefinite and contingent.

Respondent contends that Exxon's well-site DRR obligations should not be regarded as fixed because of the possibility that Exxon might surrender or assign its interest in PBU, along with the related DRR obligations, to some other oil company. The mere possibility of assignment, however, is not sufficient to prevent tax accrual because the same argument could be made with respect to every fixed liability that a taxpayer otherwise would accrue. In any event, the PBU partners are not permitted to assign their interests in the PBU without approval from Alaska, and the State would not approve an assignment that would ignore the well plugging and well-site DRR obligations. Further, the Unit

Agreement does not allow an owner to avoid its DRR obligations by transferring its ownership interest in PBU.

The Reasonableness of Exxon’s $24 Million Estimate for Prudhoe Bay Well-Plugging and Other Well-Site DRR Costs

Of the total $928 million estimated by Exxon’s experts for total fieldwide DRR costs, $111.6 million relates to well-site DRR costs--$85 million for plugging the 645 wells and $26.6 million for closing the pits next to the wells and for cleaning up the 37 well sites. We discuss below the reasonableness of Exxon’s estimate of $24 million (22 percent of $111.6 million) for its share of Prudhoe Bay well plugging and well-site cleanup, the only DRR costs that we have determined satisfy the first prong of the all-events test of the accrual method of accounting. Respondent claims that all of Exxon’s estimated Prudhoe Bay DRR costs are too remote and speculative, that they cannot be ascertained with reasonable accuracy, and therefore that they do not satisfy the second prong of the all-events accrual test.

To protect against hydrocarbon leakage after abandonment of the wells, AOGCC regulations require that upon abandonment each well must be “plugged in a manner which will permanently confine all oil, gas, and water to the separate strata originally containing them.” This procedure involves setting a series of cement plugs to seal the wells. Exxon presented a cost-effective plan, which makes use of coiled tubing units, for setting such plugs. Exxon’s plugging method achieves the regulatory objectives of isolating the well substances within their separate strata and preventing the leakage of hydrocarbons after well abandonment.

Exxon’s estimated DRR costs associated with plugging wells include wages, rental of equipment, supplies, and hauling of equipment and materials.

We reiterate that in the oil industry well plugging and related site cleanup are common events. As a general matter and based on such experience, the costs of such DRR work is reasonably estimable.

John B. Willis, currently with Halliburton Energy Services, Inc., a leading oil well service company, prepared Exxon’s plan for and estimated the cost of plugging the Prudhoe Bay oil wells in 1970 and 1980 dollars at a total of $131,976 for each of the 645 wells for which an estimate was done (reflecting total PBU estimated costs for well plugging of $85,124,800 of which Exxon’s 22-percent share would be $18,727,456). Mr. Willis supervised the drilling and plugging of wells at Prudhoe Bay during the 1970's. We accept Mr. Willis’ estimates of Exxon’s well-plugging costs for the Prudhoe Bay field.

During the drilling of wells, mud is pumped into the well bore. Mud and drill “cuttings” move to the surface as the wells are drilled and must be contained when they exit from the top of the wells. To accomplish that containment, the PBU owners constructed “reserve pits” at the drill sites by enclosing a portion of the tundra with gravel dikes or berms. They constructed other pits, called “containment” and “flare” pits, to collect escaped hydrocarbons during oil production.

The AOGCC regulations from the period at issue provided that, upon abandonment of wells, the pits at well sites must be filled and the well sites left in a clean and generally level condition. Exxon’s plan for closing the pits upon abandoning and plugging the wells uses the so-called freeze-back-in-place method, which involves placing on each pit a 6-foot layer of gravel fill with a domed cap. The insulating effect of the gravel cover keeps the waste located in the pits permanently frozen, thereby containing the waste in place. During the years in issue, freeze-back in place represented an acceptable method of pit closure.

Exxon’s estimated DRR costs associated with pit closures include wages, fuel, rental of equipment, supplies, and hauling of gravel and equipment.

Charles E. Wilson, a civil engineer and employee of Harding Lawson Associates, a large environmental remediation and civil engineering firm with an Anchorage office, developed Exxon’s pit closure plan and estimated the related DRR costs. Mr. Wilson is experienced in closing pits and moving gravel on the North Slope.

Mr. Wilson estimated total PBU pit closing costs in the Prudhoe Bay field in 1970 and 1980 dollars to be $152,720 for each of the 174 pits for which an estimate was done (for a total cost for all of the Prudhoe Bay pits of $26,573,366, of which Exxon’s 22-percent share would be $5,846,141). We accept Mr. Wilson’s estimates of Exxon’s pit closing costs for the Prudhoe Bay field.

We conclude that $24 million for Exxon’s share of the costs of Prudhoe Bay well-site DRR represents, as of the end of the years in issue, a reasonable estimate of such future costs.[5]

[5] Obviously, the specific years in which wells are constructed would control the specific year in which related estimated well-site DRR costs would be accrued, subject to resolution of the remaining issues herein.

Accrual of Estimated Prudhoe Bay Well-Site DRR Costs as Capital Costs or as Current Business Expenses

Although we are satisfied that Exxon’s attempted accrual of $24 million in estimated DRR costs relating to Prudhoe Bay well plugging and well-site cleanup would satisfy the all-events test of the accrual method of accounting, respondent argues that Exxon may not, without respondent’s permission, accrue such $24 million into the tax bases of its share of Prudhoe Bay capital asset costs and claim thereon accelerated depreciation, investment tax credits (ITC), and intangible drilling costs (IDC). We agree with respondent.

We believe that Exxon’s claim to such capitalization, accelerated depreciation, ITC, and IDC constitutes a substantial deviation from the current ordinary business expense treatment of Prudhoe Bay well-site DRR costs (at the time of performance of related DRR work) that Exxon has been using on its Federal corporation income tax returns as filed and that such a change would constitute a “change” in Exxon’s method of accounting for DRR costs for which respondent’s permission is required. See sec. 446(e), particularly the last sentence of sec. 1.446-1(e)(2)(ii)(b), and (3)(i), Income Tax Regs. Not having obtained such permission and absent a finding herein that respondent abused his discretion in not granting such permission, Exxon is not allowed to accrue estimated Prudhoe Bay well-site DRR costs into the capital cost bases of the wells and the well-site equipment and to claim accelerated depreciation, ITC, and IDC relating thereto. We find no abuse in respondent's refusal to authorize this change in the accrual of Exxon's DRR costs.

The question remains as to whether Exxon should be allowed its alternative claim to accrue the estimated $24 million in well-site DRR costs (that we have concluded satisfy the all-events test) as current ordinary and necessary business expenses in the year in which oil wells are drilled. Treating such DRR costs as ordinary business expenses would be consistent with Exxon's tax return treatment under which such expenses were so accrued--albeit in the year in which the DRR work was performed.

The proposed modification to Exxon's accrual as ordinary business expenses of estimated well-site DRR costs (from the year in which the related DRR work is performed to the year in which wells are drilled and the DRR obligation first becomes fixed) arguably, as Exxon asserts, would constitute a mere "correction" in the application of the all-events test to such costs (namely, the costs would be regarded as being fixed and reasonably estimable--and therefore as satisfying the all-events test--in the years the wells are drilled, rather than in later years in which the DRR work is performed).

Section 1.446-1(e)(2)(ii)(b), Income Tax Regs., provides, among other things, that a mere technical "correction" in the application of a taxpayer's existing method of accounting for the same or similar items may be made without obtaining respondent's permission. For examples of situations where certain modifications in the accrual of items under the all-events test were held to constitute not “changes” in methods of accounting for such items but mere “corrections” in the application to such items of the all-events test of the accrual method of accounting (for which corrections respondent’s permission was not required) see Northern States Power Co. v. United States, 151 F.3d 876, 883-885 (8th Cir. 1998); Gimbel Bros., Inc. v. United States, 210 Ct. Cl. 17, 535 F.2d 14, 21-23 (1976); Standard Oil Co. v. Commissioner, 77 T.C. 349, 381-383 (1981).

In Ohio River Collieries Co. v. Commissioner, 77 T.C. 1369 (1981), we recognized that under the all-events test accrual of estimated strip-mining reclamation costs as ordinary and necessary business expenses may be appropriate in the year the land is disturbed, rather than in the year the reclamation work is performed. Arguably, in light of that case, Exxon’s attempted modification to the accrual of estimated DRR costs from the year DRR work is performed to the year in which wells are drilled would qualify as a mere correction in Exxon’s method of accounting for such well-site DRR costs for which respondent’s permission would not be required. In light, however, of our resolution of the next issue we need not, and we do not, decide this issue.

Distortion of Income

Respondent argues that Exxon's alternative accrual as ordinary business expenses in the year wells are drilled of the $24 million in estimated Prudhoe Bay well-site cleanup costs (that we determine satisfy the all-events test of the accrual method of accounting) would distort Exxon's income. Exxon responds that under its alternative claim to currently expense estimated Prudhoe Bay DRR costs its income would not be distorted for Federal income tax purposes.

Section 446(b) grants respondent broad discretion to determine whether a particular method of accounting clearly reflects income and to impose such method of accounting as in respondent's opinion does clearly reflect income. Respondent's determination is to be respected unless it is found to be an abuse of discretion. See Thor Power Tool v. Commissioner, 439 U.S. 522, 532 (1979); Ford Motor Co. v. Commissioner, 71 F.3d 209, 212 (6th Cir. 1995), affg. 102 T.C. 87 (1994); Prabel v. Commissioner, 882 F.2d 820, 823 (3d Cir. 1989), affg. 91 T.C. 1101 (1988).

Herein, under Exxon's alternative claim, Exxon would fully write off $24 million in estimated well-site DRR costs immediately in the years wells in the Prudhoe Bay oil field were drilled. Such current expense treatment would be unrelated to the years thereafter in which oil production from the wells occurred and income from sale of the oil was realized and unrelated to the years in which oil production ceases, the wells are plugged, and DRR costs are incurred.

We sustain respondent's determination that Exxon's attempted accrual of $24 million in estimated well-site DRR costs as current business expenses in the years wells are drilled would result in a distortion of Exxon's income.

Decisions will be entered under Rule 155.