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Decision No. 90841 SEP 25 1979

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company and its wholly owned subsidiary Natural Gas Corporation of California, for Commission approval of the Project Letter for Funding a Natural Gas Exploration and Development Program with Pacific Transmission Supply Company.	Application No. 58792 (Filed April 9, 1979)

Malcolm H. Furbush, Robert Ohlbach and Gilbert L. Herrick, Attorneys at Law, for Pacific Gas and Electric Company and Natural Gas Corporation of California, applicants.
Sylvia M. Siegel, for Toward Utility Rate Normalization, protestant.
Henry F. Lippett, 2nd, Attorney at Law, for California Gas Producers Association; Jack W. Shuck, Attorney at Law, for Pacific Transmission Supply Company; and Douglas Porter, Attorney at Law, for Southern California Gas Company; interested parties.
Richard D. Rosenberg, Attorney at Law, for the Commission staff.

O P I N I O N

On October 16, 1978, Pacific Gas and Electric Company (PG&E) and its wholly owned subsidiary Natural Gas Corporation of California (NGC) submitted Project Letter No. 78-M requesting approval to fund natural gas exploration and development activities in the Rocky Mountains under the Gas Exploration and Development Adjustment (GEDA) procedures authorized by Decision No. 88121 dated November 22, 1977. On April 9, 1979 Project Letter No. 78-M was docketed and assigned Application No. 58792.

Public hearing in this matter was held before Administrative Law Judge O'Leary at San Francisco on June 18, 19, 20, and 21, 1979. The matter was submitted on the latter date.

The proposed project involves agreements whereby Pacific Transmission Supply Company (PTS) will farm out or assign its leasehold interest in approximately 1,600,000 acres in the Rocky Mountains to NGC. PTS is a wholly owned subsidiary of Pacific Gas Transmission Company (PGT) which is an interstate pipeline company under jurisdiction of the Federal Energy Regulatory Commission (FERC) and is 53 percent owned by PG&E. If the project is approved as proposed, NGC will fund all drilling and operations in return for PTS' working interest in each prospect. PTS will retain a 1/16 overriding royalty convertible to a 50 percent net profits interest.

Background

In the early 1970's it became apparent that the natural gas supplies available to California from traditional sources were declining and new sources of supply would be required if California distribution utilities were to meet the requirements of their customers. In response, the Commission among other things adopted procedures allowing California distribution utilities to recover in rates the costs incurred in gas exploration and development activities, and requiring return to the ratepayer of any benefits resulting from such activities.

By Decision No. 80878 dated December 19, 1972, the Commission granted PG&E authority to participate in natural gas exploration and development activities through its subsidiary NGC. Under such authority PG&E was limited to expenditures of $3,000,000 per year for a five-year period, one-half of which was to be expensed and the other half rate based. Additionally, by Decision No. 81898 dated September 25, 1973, the Commission established extensive GEDA procedures applicable to the Pacific Lighting System. Under such procedures Southern California Gas Company (SoCal) was permitted to file project letters on a project-by-project basis, and to recover the associated cost of service for Commission approved projects in rates charged to customers. SoCal's authority to enter into new or revised projects was limited by Decision No. 81898 to a period of three years.

On March 2, 1976, the Commission opened an order instituting investigation (OII) into the exploration and development programs of the California distribution utilities (Case No. 10056). The OII included a consideration of whether the existing programs should be maintained, expanded, reduced, or eliminated. SoCal subsequently filed an application (Application No. 56471) for authorization to continue to submit new and/or revised GEDA projects for a three-year period. Additionally, PG&E filed an application (Application No. 56709) for comprehensive GEDA procedures, similar to the procedures granted to SoCal, to replace its limited program authorized by Decision No. 80878.

Case No. 10056 resulted in Decision No. 88121 dated November 22, 1977. Decision No. 88121, among other things, granted SoCal's request to submit new and/or revised projects for Commission approval for an additional three-year period. Additionally PG&E was authorized to file revised tariff schedules establishing GEDA procedures similar to the procedures granted to SoCal in Decision No. 81898, as modified by Decision No. 88121. The major provisions of the currently effective GEDA procedures applicable to PG&E and SoCal GEDA filings are as follows:

1. Project letters must be filed and Commission approval obtained prior to commitment of funds to new projects.

2. The staff is required to review project letters and prepare resolutions for Commission approval. Staff reports and recommendations to the Commission are to be mailed to interested parties in Case No. 10056.

3. New projects under GEDA are limited to United States territories, including Alaska and federal offshore areas.

4. New projects are limited to projects where the utilities obtain an equity position or working interest. Advance payments1/ or similar funding arrangments are prohibited unless the project letter sets forth extenuating circumstances.

5. The utilities are required to submit annual reports on the GEDA projects and meet with the staff to review the status of each project.

6. The annual cost-of-service resulting from all GEDA activities is limited to $50,000,000 for each utility.

7. The utilities are authorized to offset the cost of GEDA projects in rates and to file rate adjustments to recover the prospective cost of service of approved projects and to balance past period under- or over-collections. Under the GEDA ratemaking mechanics the exploration and development subsidiary operates as a nonprofit, nonloss company. It receives its required investment from the internally generated funds of the parent utility and returns any revenue received. The parent utility reflects the gross investment minus tax credits as a rate base item and is permitted a return based on the rate most recently found reasonable by the Commission, assuming a 50-50 debt/equity ratio. The net rate base is amortized over the life of the project on a unit-of-production basis. Revenues are credited to the cost of service. The net cost of service thus derived, plus an allowance for franchise and uncollectibles is spread to total utility sales on a uniform cents/therm basis. If an individual project is unsuccessful and no production results, the GEDA ratemaking procedures provide for the amortization of the net investment over a five-year period.

1/ Advance payments refer to funding development activities in exchange for a right to purchase associated production. No working interest in production is obtained.

PTS has conducted an extensive exploration and development program since 1971 and has a large leasehold position in the Rocky Mountains in the same general area as NGC. With properties located in Wyoming, Utah, Montana, Colorado, and Idaho, PTS owns leasehold interests in approximately 1,600,000 acres. The working interests vary from 25 percent to 100 percent and are generally concentrated in 12 prospects. Since 1971, PTS has expended over $54 million and participated in drilling over 100 wells, but the majority of the acreage is undeveloped. Unlike NGC, PTS exploration and development activities are supported by stockholder funds. Appendix A attached hereto provides a tabulation, by major prospect, of the acreage in which PTS has a leasehold position and illustrates the general location of the various prospects.

In Case No. 10056 the staff and other interested parties expressed concern about the potential conflict of interest that exists where separate exploration and development programs under a parent utility are supported on the one hand by stockholder funds, and on the other by ratepayer funds. In Finding 21 of Decision No. 88121, the Commission stated:

> "SoCal and PG&E both have stockholder-financed exploration companies. Exploration by such companies has the potential to conflict with the exploration activity of GEDA and EEDA exploration. Such potential conflict may be avoided by requiring geographical separation of operations and by requiring joint participation where operations are now in the same area. Conflict may be reduced if additional stockholder investment is not advanced to finance exploration activity."

Apart from the potential conflict discussed above, PG&E contends that PGT is not generating sufficient internal funds to adequately explore for and develop the extensive gas leases it has acquired, and that absent GEDA funding PTS will have to make arrangements with outside parties to get drilling funds, resulting in a probable loss of gas supplies for California.

Project Proposal

PTS and NGC propose to enter into agreements whereby NGC would take assignment of PTS' working interest in its Rocky Mountain leaseholds and finance exploration and development activities through GEDA funding. The proposed assignment would be accomplished under two agreements. Future drilling on leases on which PTS has producing wells would be under the Farmout Agreement a copy of which is set forth in Appendix B of Exhibit 4. On the remainder of the leases, PTS would assign its working interest to NGC through a series of subleases under the assignment a copy of which is set forth in Appendix C of Exhibit 4. The Farmout Agreement covers approximately 41,000 acres. There are 121 undrilled drillsites subject to an NGC farm-in option under the Farmout Agreement.

Under the Farmout Agreement NGC would acquire 100 percent of PTS' working interest subject to a 1/16 overriding royalty of PTS convertible at payout to a 50 percent working interest.

Under the assignment (sublease) PTS would assign its leasehold working interest in each of its prospects to NGC, retaining a 1/16 overriding royalty, or a 50 percent net profits interest, whichever is greater. Net profits (net loss) are to be calculated monthly by deducting current expenses (leasehold rentals, seismic costs, unsuccessful drilling expenditures, operating costs, severance taxes, and amortization) plus unliquidated net losses from previous months, from net production revenues (total production revenues less royalties and overriding royalties). PTS' share of revenues would be determined under the above accounting on a prospect-by-prospect basis (i.e., exploration and development in one prospect will have no effect on the allocation of revenues in other prospects).

For planning purposes, PTS has projected a 10-year drilling program. The assumptions underlying the projected drilling program are shown in Appendix B attached hereto and include the projected number of wells drilled, success rates, flow rates, and well costs.

Because of the scope of the project and the affiliated relationships of the parties involved, an agreement was reached between applicants and the staff to obtain an independent evaluation of the future potential of the prospect areas. DeGolyer and MacNaughton (D&M) was retained for this purpose. The success rates estimated by PTS and D&M are as follows:

Item	Exploration Wells % Successful	Development Wells % Successful
PTS	10-33	70
D&M	10-40	70

Chapter 3 of Exhibit 4 (staff report) presents production and the unit wellhead cost of production estimated to result from implementation of the proposed project. The exhibit points out that although it is difficult to forecast production and costs, it is possible to develop a probable range of results making certain reasonable assumptions.

The expected gas production and wellhead costs to the ratepayer of the proposed drilling program on a year-by-year basis were estimated by the staff under assumptions consistent with the number and type of wells, success rates, flow rates, and drilling costs included in Appendix B. The results are tabulated in Cases I through III on pages 16 through 21 of Exhibit 4. A "pessimistic"2/ scenario is included in each case. Cases I through III compare the estimated unit cost of service with the estimated cost of gas should the gas be produced by others and sold to PG&E at the market price. The market price is assumed to be the statutory price set by the NGPA

2/ In the pessimistic scenario, Pleasant Valley is assumed to have only a small discovery in the first year and Centennial Basin, Hoback, Rock Creek, Southwest Rangely, and Hoback River are assumed to have no discoveries.

through 1984 and is further assumed to rise at the inflation rate following scheduled deregulation at January 1, 1985. If, after scheduled deregulation, the wellhead market price rises more slowly than the inflation rate, the savings to the ratepayer reflected in the various cases will be less. If the price rises faster than the inflation rate, the savings will be greater.

The most likely scenario under Case I provides estimates of production and costs under the assumptions reflected in Appendix B including the assumption that all drilling in the 10-year program is carried out as planned. Production is estimated to be 307.4 Bcf from PTS working interest in future wells plus an additional 39.3 Bcf which is expected to be acquired by virtue of one or more of the other working interest owners going nonconsent on their share of the well costs. To the extent other owners go nonconsent, NGC's drilling costs will be higher; but NGC is entitled to recover those costs plus a substantial penalty from any production. Total estimated production is 346.6 Bcf. In the "pessimistic" scenario 163 fewer wells would be drilled with a resultant production of 212 Bcf over the expected life of the project.

In both the "most likely" and "pessimistic" cases, NGC's share of the gas produced is projected to be less expensive than gas purchased at the market price. The projected savings in 1979 dollars are 41¢/Mcf in the most likely scenario and 34¢/Mcf in the pessimistic scenario.

Case II assumes that NGC does not participate in the development of PTS' partially developed leases (Farmout Agreement) and goes forward on the basis of the assignment (sublease) only. Under this assumption production is projected to be 307 Bcf and the savings in 1979 dollars are estimated to be 39¢/Mcf in the most likely scenario, and 172 Bcf and 29¢/Mcf, respectively, in the pessimistic scenario.

Case III is the same as Case I but assumes NGC is assigned a working interest in PTS' share of existing wells. Under this assumption production is projected to be 369 Bcf and the savings in 1979 dollars are estimated to be 43¢/Mcf in the most likely scenario and 235 Bcf and 39¢/Mcf, respectively, in the pessimistic scenario.

Interim Project

The basic terms of the overall proposal were discussed with the staff in the spring of 1978. It was recognized at that time that it would take about one year for the details to be worked out and for the Commission to take action. In order to protect leases about to expire and to continue orderly exploration and development of the prospect, PG&E submitted Project Letter No. 78-I (PTS Farm-in) as an interim project to finance drilling activities in 1978 and part of 1979 through GEDA funding. In return NGC obtains 100 percent of PTS' interest in the drill site for each well drilled. PTS retains a 1/16 overriding royalty convertible to a 50 percent working interest after payout of NGC's investment. The interim project was approved on May 16, 1978, by Resolution No. G-2220.

The gross expenditures authorized by the resolution totaled $15,600,000 which was expected to be depleted by June 1979. By Resolution No. G-2283, dated June 5, 1979, the interim project was extended through the third quarter of 1979 and an additional gross expenditure of $16,000,000 was authorized.

The terms and conditions of the interim agreement are subject to revision consistent with the terms and conditions ultimately adopted by the Commission under Project No. 78-M. Should Project No. 78-M not be approved, NGC would retain the interests it obtained under the interim agreement. As of March 31, 1979, 5 wells had been completed, 10 were awaiting completion, 14 were dry holes, and 6 were drilling. The proven reserves associated with the interim drilling through March 31, 1979, excluding those wells that were still drilling, are estimated by PTS to be 44.5 Bcf. The total well costs under the interim project, excluding the cost of wells that were still drilling totaled $19,177,000. This represents a finding cost of approximately 43¢/Mcf. Finding costs are not production costs which can be accurately measured only after the program matures.

Transportation

PG&E proposes to transport Rocky Mountain gas to California through transportation and exchange agreements with Northwest Pipeline Company and El Paso Natural Gas Company. If sufficient reserves are acquired, either through exploration and development or purchases, construction of a new pipeline connecting with existing PG&E-owned facilities near Topock is contemplated.

The Commission staff recommends that the application be approved. The interested parties did not take a position. The sole protestant made an appearance the first day of the hearing and departed prior to the presentation of the first witness and did not again appear during the course of the hearing.

Findings of Fact

1. The general project area is one of the most promising areas for future natural gas resources in the "lower 48". The Potential Gas Committee in its report of April 3, 1979, estimates 103 trillion cubic feet remaining to be discovered in the probable and possible categories, or approximately 20 percent of the total lower 48 potential in the probable and possible categories, including offshore areas. Additionally, the proximity of the project area makes it attractive as a potential source of new domestic gas that could satisfy a portion of California's needs into the next century.

2. The Rocky Mountain area is rapidly being explored by many large oil and gas companies and independent producers. A number of interstate and intrastate pipeline companies are seeking gas for their customers under exploration programs of their own. Three

interstate pipelines, none of which serves California directly, pass through the area and are in a good position to buy any gas that becomes available. (See Appendix A page 2 of 2.) Applications have been filed with the FERC seeking certification of two additional interstate pipelines that would move gas from this area to the midwestern U.S.

3. Without GEDA funding California's access to Rocky Mountain gas would be much reduced. Although PTS properties would most likely be developed outside GEDA, PTS would necessarily enter into farm out agreements with others who would dispose of their share of production as they saw fit.

4. The staff analysis of GEDA costs over the life of the proposed project indicates that NGC will acquire gas for the PG&E ratepayer at a unit wellhead cost which is lower than the statutory price for new gas established by the NGPA.

5. GEDA procedures provide for a comprehensive annual review of project status and costs. Should the economics of the proposed project become unacceptable, GEDA support for subsequent funding could be restricted by the Commission. The terms of the agreement between PTS and NGC allow for the possibility that at some future time the Commission may withdraw GEDA funding. If so, NGC will retain an interest in prospects already drilled and any gas discovered, but unexplored properties will revert back to PTS.

Conclusion of Law

The application should be granted as set forth in the ensuing order.

O R D E R

IT IS ORDERED that:

1. Authority is granted pursuant to the provisions of Decision No. 88121 for Pacific Gas and Electric Company and Natural Gas Corporation of California to participate in funding Project Letter No. 78-M.

2. The cost of service associated with the funding shall be accumulated and reflected in each annual adjustment for under- and over-collections during the life of the project.

The effective date of this order shall be thirty days after the date hereof.

Dated SEP 25 1979, at San Francisco, California.

John E. Bryson
President

Vernon L. Sturgeon

Richard D. Gravelle

Claire T. Dedrick

Leonard M. Grimes, Jr.
Commissioners

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Prospect	Gross Acres	Farmout Lease Acreage	Existing Reserves Mcf [1]	Total Wells Drilled to Date [2]	Wells Drilled Under 78-I [3]	Total Additional Wells Scheduled
Southeast Flank	302,418	16,564	3,433,906	28	9	185
Red Wash	98,272	6,594	4,350,471	12	0	137
Pleasant Valley	70,599	160	886,813	5	2	80
Fontenelle	44,929	12,840	10,797,677	35	5	60
Wamsutter	52,730	2,570	621,109	17	13	54
Stone Cabin	69,465	1,080	2,069,895	8	1	43
E. Mickelson & Nylander	38,499	650	-	4	1	30
Centennial Basin	117,993	-	-	0	0	32
Hoback	12,728	-	-	4	1	5
Rock Creek & Wyoming Range	117,098	-	-	1	0	43
Southwest Rangely	35,770	160	388,192	4	0	16
Hoback River	10,874	-	-	0	0	5
SUBTOTAL	971,375	40,618	22,548,063	115	32	
Others	582,481	-	-	0	0	
TOTAL	1,553,856	40,618	22,548,063	115	32	689

1/ Existing reserves drained by existing wells are retained by PTS. Reserves discovered by future wells to be covered by Farm-in agreement or sublease.

2/ Total wells drilled in the prospect areas, some of which PTS did not participate in.

3/ Three wells have been completed as producing wells. Seven wells are suspended pending completion. Eight wells were dry holes and were plugged and abandoned. Fourteen wells are currently being drilled.

NOTE: All data are as of December 31, 1978

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APPENDIX A
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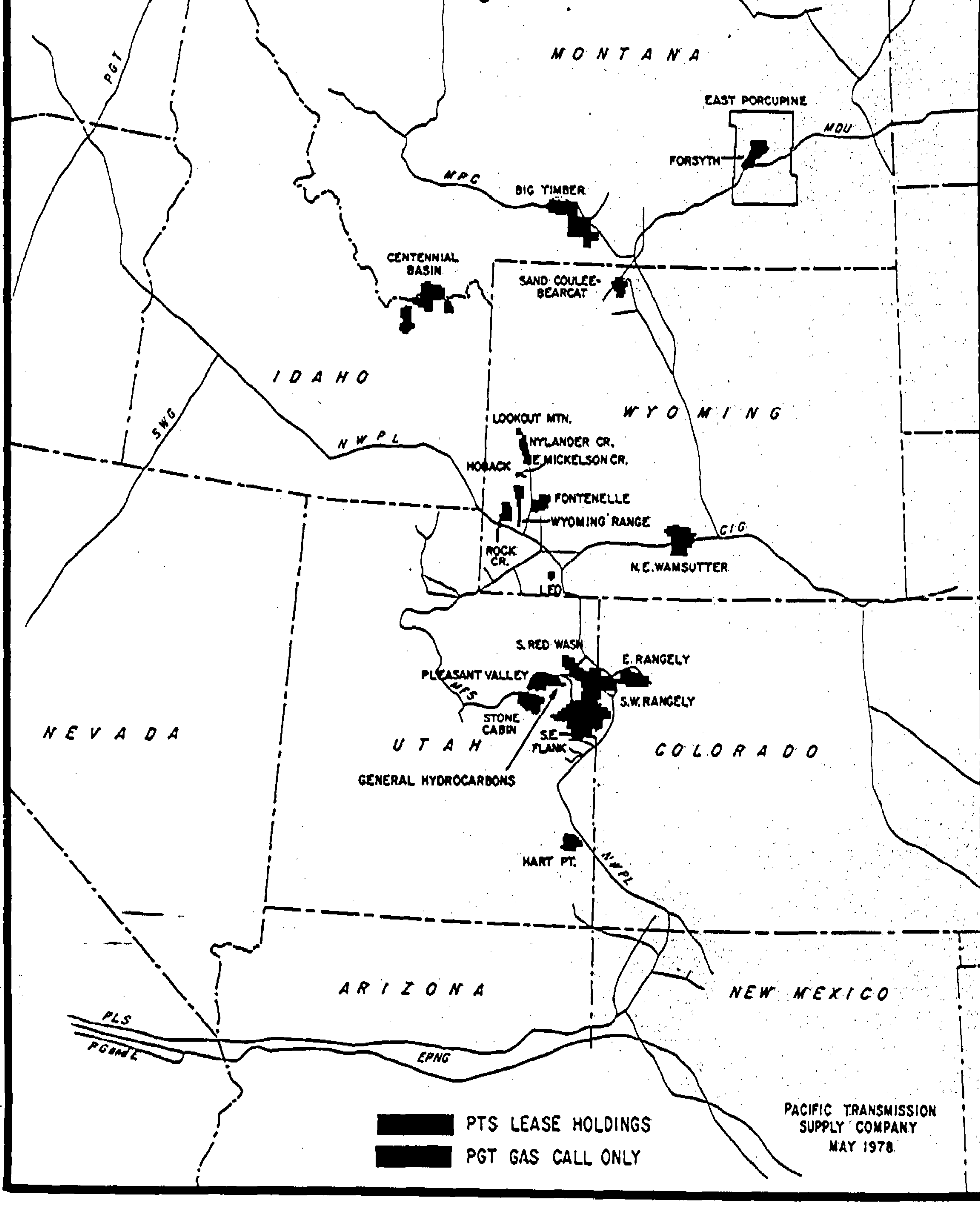

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APPENDIX B

ASSUMPTIONS

FUTURE EXPLORATION AND DEVELOPMENT PROGRAM

Line No.	* Prospect PTS Working Interest (a)	** Type (b)	1979 No. Wells Drilled (c)	1979 Predicted Success Rate % (d)	1980 No. Wells Drilled (e)	1980 Predicted Success Rate % (f)	1981 No. Wells Drilled (g)	1981 Predicted Success Rate % (h)	1982 No. Wells Drilled (i)	1982 Predicted Success Rate % (j)	1983 No. Wells Drilled (k)	1983 Predicted Success Rate % (l)	1984 No. Wells Drilled (m)	1984 Predicted Success Rate % (n)	1985 No. Wells Drilled (o)	1985 Predicted Success Rate % (p)	1986 No. Wells Drilled (q)	1986 Predicted Success Rate % (r)	1987 No. Wells Drilled (s)	1987 Predicted Success Rate % (t)	Total Wells (u)	Assumed Average Initial Year Flow MCFD Per Well (v)	Well Costs to Casing Pt. ($000) (w)	Completed Well Costs ($000) (x)
1	Southeast Flank (37.50)	Exploration	20	33	10	33	9	33	4	33	3	33	2	33	2	33	2	33	0	0	52	750	520	850
2		Development ▶	0	0	8	70	17	70	14	70	15	70	18	70	16	70	16	70	18	70	120			
3		Development ◀	5	70	8	70	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13			
4	South Red Wash (66.67)	Exploration	8	10	9	20	14	20	5	20	3	30	1	30	1	30	1	30	0	0	42	450	300	550
5		Development ▶	0	0	0	0	5	70	10	70	15	70	11	70	11	70	11	70	12	70	75			
6		Development ◀	0	0	0	0	5	70	9	70	6	70	0	0	0	0	0	0	0	0	20			
7	Pleasant Valley (75)	Exploration	5	10	4	10	7	10	5	10	3	10	3	10	2	20	2	20	0	0	31	450	550	950
8		Development ▶	0	0	1	70	3	70	5	70	7	70	7	70	8	70	8	70	10	70	49			
9		Development ◀	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
10	Fontenelle (37.50)	Exploration	0	0	0	0	0	0	0	0	0	0	0	0							0	700	280	680
11		Development ▶	0	0	0	0	0	0	0	0	0	0	0	0							0			
12		Development ◀	10	70	10	70	10	70	10	70	10	70	10	70							60			
13	N E. Wamsutter (37.50)	Exploration	5	20	4	20	3	30	2	30	2	30	0	0							16	1,000	500	950
14		Development ▶	2	70	5	70	6	70	7	70	7	70	9	70							36			
15		Development ◀	2	70	0	0	0	0	0	0	0	0	0	0							2			
16	Stone Cabin (37.50)	Exploration	4	20	5	20	5	20	5	20	4	20	3	20	2	20	1	20			29	750	300	550
17		Development ▶	0	0	0	0	1	70	2	70	4	70	4	70	0	0	0	0			11			
18		Development ◀	0	0	1	70	1	70	1	70	0	0	0	0	0	0	0	0			3			
19	E. Mickelson/Nylander (75/100)	Exploration	5	30	4	30	4	30	3	30	3	30	3	30							22	600	600	1,000
20		Development ▶	0	0	0	0	1	70	2	70	2	70	2	70							7			
21		Development ◀	0	0	1	70	0	0	0	0	0	0	0	0							1			
22	Centennial Basin (50)	Exploration	1	30	2	30	2	30	2	30	3	30	2	30	1	30	1	30	0	0	14	1,500	700	1,100
23		Development ▶	0	0	0	0	0	0	0	0	2	70	3	70	4	70	4	70	5	70	18			
24		Development ◀	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
25	Hoback (50)	Exploration	1	30	1	30	1	30	2	30											5	1,500	937	1,400
26		Development ▶	0	0	0	0	0	0	0	0											0			
27		Development ◀	0	0	0	0	0	0	0	0											0			
28	Rock Creek/Wyoming Range (100)	Exploration	2	10	4	10	4	30	2	30	2	30	3	30	1	30	0	0	0	0	18	1,500	936	1,350
29		Development ▶	0	0	0	0	0	0	2	70	2	70	4	70	5	70	6	70	6	70	25			
30		Development ◀	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
31	Southwest Rangely (25)	Exploration	2	30	2	30	4	30	4	30	4	30									16	450	350	550
32		Development ▶	0	0	0	0	0	0	0	0	0	0									0			
33		Development ◀	0	0	0	0	0	0	0	0	0	0									0			
34	Hoback River (100)	Exploration	1	10	1	20	2	30													4	1,500	945	1,575
35		Development ▶	0	0	0	0	0	0													0			
36		Development ◀	0	0	0	0	0	0													0			
37			73		80		104		96		97		83		53		52		51		689			

*The working interest percentage shown is approximate. Prospects may include leases in which PTS owns a working interest different than shown.

**Development wells are qualified to show wells greater than 2½ miles (▶) from existing wells or less than 2½ miles (◀) from existing wells.

NOTES:

1) Well costs shown are total well costs in 1979 dollars with costs escalated 5% per year.

2) The above nine years of drilling is part of a ten year plan which began in 1978. The drilling in 1978 was funded under 781 (Farm in; Pacific Transmission Supply Company).

3) Each well is assumed to drain 320 acres except Fontenelle wells which drain 160 acres, and N E. Wamsutter.

4) Each well is expected to flow for 20 years with decline rates in % per year. The decline rate percentages shown are for the years 1, 2, 3 and 4 respectively in the life of the well with the last figure shown to be used for all remaining years the well is assumed to flow

a. Southeast Flank, Red Wash, Pleasant Valley, Rock Creek, Wyoming Range and Hoback River: 40, 20, 14, 11, 9.

b. Fontenelle, N E. Wamsutter, Stone Cabin, E. Mickelson/Nylander, Centennial Basin, Hoback and S W. Rangely: 40, 20, 14, 14, 9.

5) The above projected exploration program is tentative. The final outcome of drilling plan is subject to drilling success, rig availability, and available funding.