

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILE 8672

2103 SCOMM 79: HOUSE SPEC. COMM. ON OIL & GAS, 1991-1992

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SCOMM 79: HOUSE SPECIAL COMMITTEE ON OIL & GAS, 1991-92

MEMBERSHIP:

REPRESENTATIVE BILL HUDSON, CHAIR
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REPRESENTATIVE KAY BROWN

Established by HR 1, 1991

Contents: 1 1/2' of files. 49 cassettes are also available of meetings held 1/28/91 to 4/28/92.

LIST OF FILES (PAGE 1) MICROFICHE #

1. ANS PRODUCTION FORECAST, 1/23/92
2. BP PRESENTATION, 3/20/92
3. CITIZENS OVERSIGHT COUNCIL SPILL
LIABILITY REPORT
4. COOK INLET SPILL OVERVIEW, 1/15/92
5. EXXON VALDEZ SETTLEMENT - 3-RING BINDER
(PART 1)
6. EXXON VALDEZ SETTLEMENT - 3-RING BINDER
(PART 2)
7. HOUSE FINANCE / HOUSE OIL & GAS JOINT
MEETING, 1/17/92
8. HOUSE FINANCE / HOUSE OIL & GAS JOINT
MEETING, 1/21/92
9. OIL & GAS WORK SESSION, 1/27/92
10. HB 190
11. HB 196
12. HB 212
13. HB 299

SCOMM 79: HOUSE SPECIAL COMMITTEE ON OIL & GAS, 1991-92

LIST OF FILES (PAGE 2)

MICROFICHE #

- 14. HB 312
- 15. HB 339
- 16. HB 407
- 17. HB 433
- 18. HB 501
- 19. HB 540
- 20. HB 557
- 21. HB 559
- 22. HJR 17
- 23. HJR 21
- 24. HJR 32
- 25. HJR 36
- 26. SB 46

SCOMM

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Recommended Approach to Moving Ahead on North Slope Royalty Gas Sales

- Request for Proposal (RFP) for long-term dedication of half of Alaska's Prudhoe Bay in-kind royalty gas (~1.5TCF)
 - work with all potential consumers
 - contract development with Royalty Board and Legislature under existing regulations
 - contract terms for consideration would include:
 - signing bonus(es); contract maintenance payments prior to sales and investment credit offsets; and "highest of" pricing terms
- Continue technical work with all project sponsors through Joint Pipeline Coordinator's Office
- Analyze production management implications of gas sales on all North Slope oil and gas fields
 - confidential review of Prudhoe Bay intermediate reservoir modeling results
 - update all plans of development
- Maintain contact with other North Slope gas owners on progress in marketing gas
- Participate in any joint consumer/producer/project sponsor studies

H.C. Heinze
1/23/92

**PRESENTATION TO THE
HOUSE FINANCE AND
HOUSE OIL AND GAS COMMITTEES**

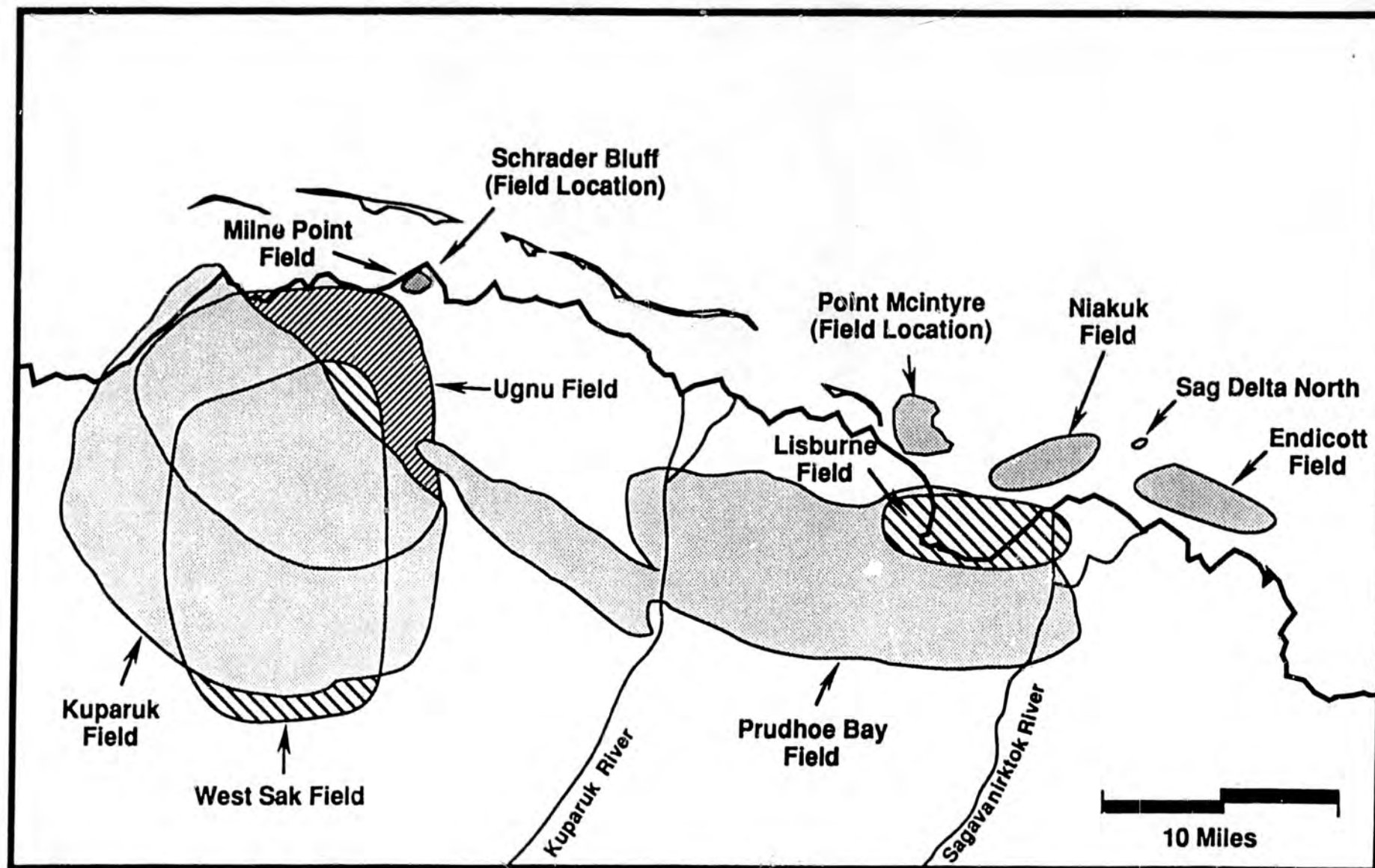
**KEVIN MEYERS, ARCO ALASKA, INC.
DAVE SZABO, BP EXPLORATION (ALASKA), INC.**

JANUARY 23, 1992

Outline

- **Prudhoe Bay Field Background** D. J. Szabo
- **Prudhoe Bay Development History** D. J. Szabo
- **Field Maintenance** D. J. Szabo
- **Future Development** K. O. Meyers
- **PBMGP Public Hearing** K.O. Meyers
- **Major Gas Sales** K. O. Meyers

North Slope Oil Fields



PRUDHOE BAY FACT SHEET

FIELD AREA	150,000 Acres (234 sq. miles)
Original Liquids In Place	22 Billion Barrels
Original Gas In Place	46 TCF
Total Liquids Production to 1/1/92	7.6 Billion Barrels
Remaining Reserves	Approximately 4.4 Billion Barrels
Current Liquid Rate	1.3 Million BPD
Current Gas Production	5.3 Billion CFD
Current Water Production	1 Million BPD
Current Wells	1,080
Total Projected Wells	1,300 +

History - Development Highlights

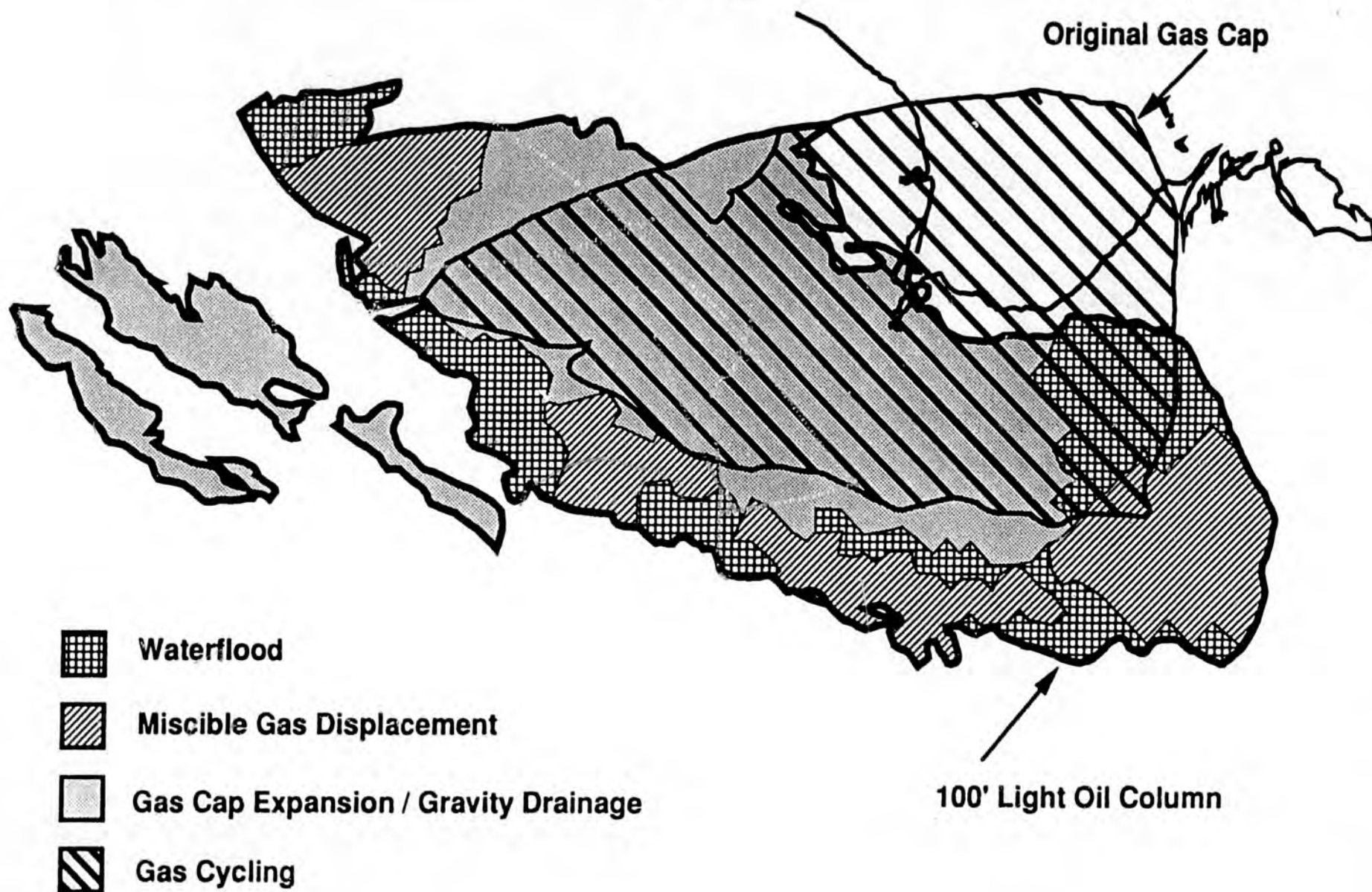
- Field start-up 1977
- Low pressure separation 1982
- Produced water injection 1982
- 80-Acre drilling 1982
- Flow Station #3 injection project (FS-3 IP) 1982
- Artificial lift (Gas Lift) 1984
- Source water injection 1984
- Central gas facility (CGF) start-up 1987
- Large-scale miscible gas injection (PBMGP) 1987
- West End start-up 1988
- Gas Handling Expansions (GHX-1) 1990
- Hurl State start-up 1990
- 40-Acre drilling pilots 1991
- GHX-2 early opportunities 1991
- Produced water handling expansions 1989-91
- NWFB infill drilling phase I 1992

DEVELOPMENT COSTS TO DATE 22 BILLION DOLLARS (1991 \$)

Reservoir Processes

- **Reservoir is being depleted by four dominant processes:**
 - **Gas cap expansion/Gravity Drainage**
 - **Waterflood**
 - **Miscible gas displacement**
 - **Gas cycling**
- **Each process individually very efficient and relatively easy to manage**
- **Effective management of all processes requires the melding of the processes into an integrated strategy which maximizes the ultimate hydrocarbon recovery of the field**

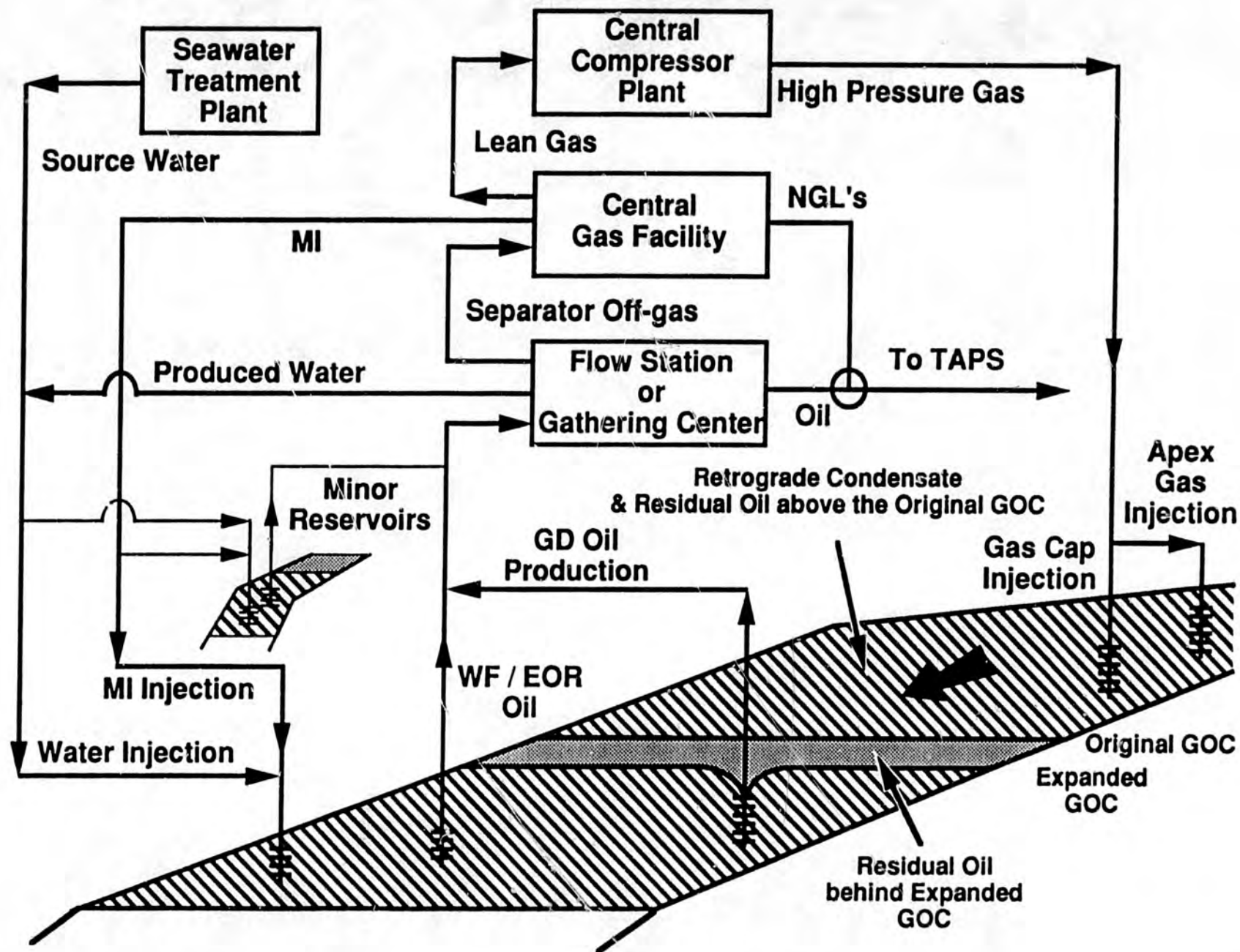
Prudhoe Bay Development Plan Recovery Processes as of 1/91



Reservoir/Facility Integration

- **Current infrastructure is a combination of highly integrated systems**
 - **Four dominant reservoir processes**
 - **Six integrated production centers**
 - **Centralized gas processing/compression**
- **Continued development of Prudhoe Bay must recognize, understand, and enhance the intricate balance of reservoir and surface processing mechanisms**

PBU Facilities / Reservoir Schematic



Wellwork/Capacity Sustainment

- Well stimulation/workover program during next five years
 - 50 fracture treatments per year
 - 300 non-frac acid/chemical treatments per year
 - 200 non-rig workover jobs per year (gas/water shut-offs, profile modifications)
 - 85 workovers per year to repair wells
 - 35 sidetrack (replacement) wellbores per year
- 85 MBOPD average yearly rate benefit
- ^{\$225} ~~\$22~~ MM average yearly cost

Infrastructure Optimization and Maintenance

- **Sidetracks (re-use of existing wellbores)**
- **Debottlenecking to improve facility efficiency**
- **Corrosion control and repair**
- **Low cost tie-ins for new wells**
 - **"Twinned" wells**
 - **Re-use facilities from suspended/abandoned wells**

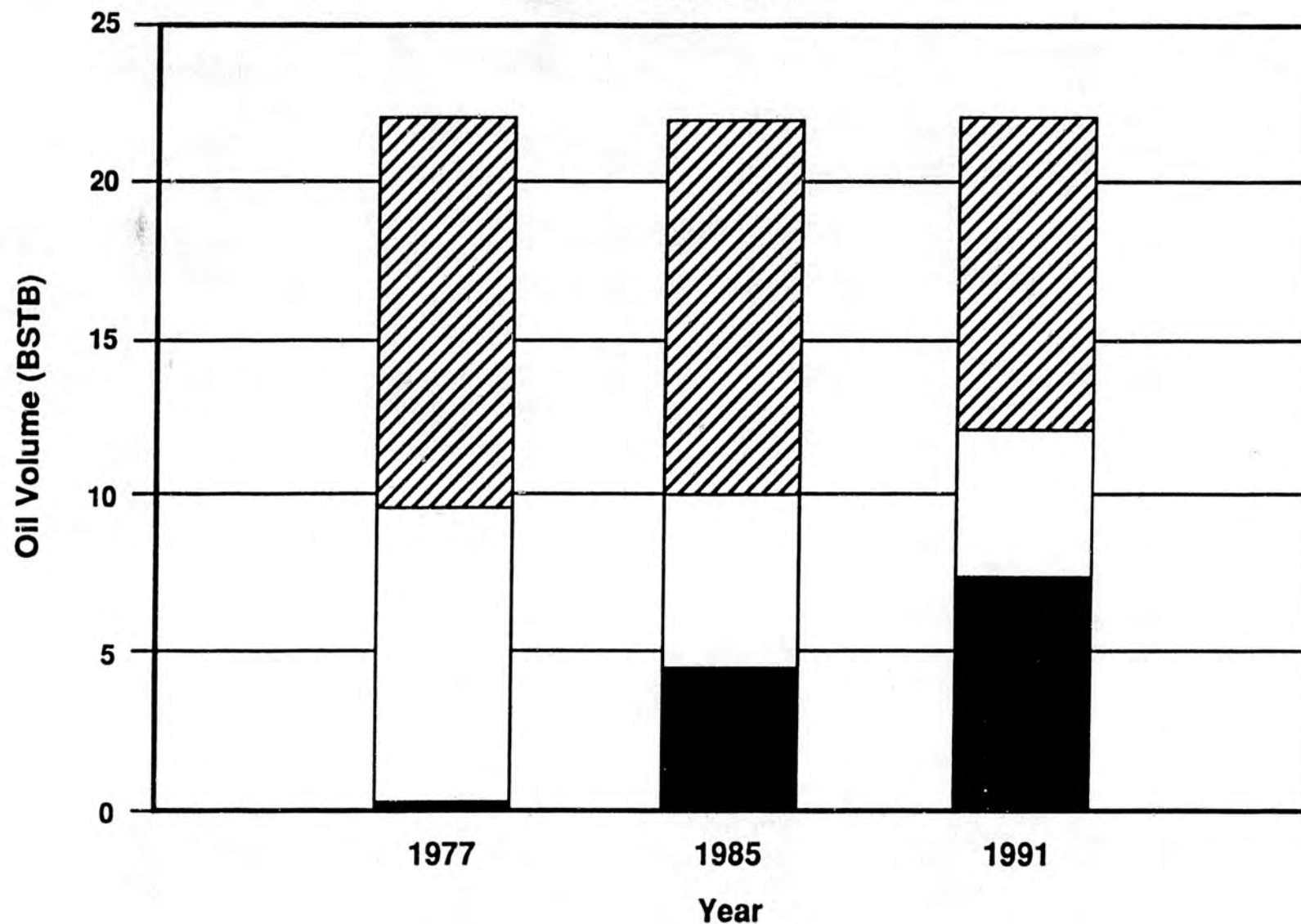
Prudhoe Bay Development

- **Sequential, deliberate, and logical evolution**
 - **Based on reservoir performance, laboratory analysis, and geological and engineering studies**
 - **Exploits each region of the reservoir in a manner which maximizes ultimate recovery**
 - **Preserves gas for future sales**
- **State of the art technology has and will continue to be applied to maximize Prudhoe Bay recovery**
- **Reservoir performance is exceeding expectations**

ALASKA STATE LEGISLATURE
PRUDHOE BAY RESERVOIR DEVELOPMENT AND MANAGEMENT

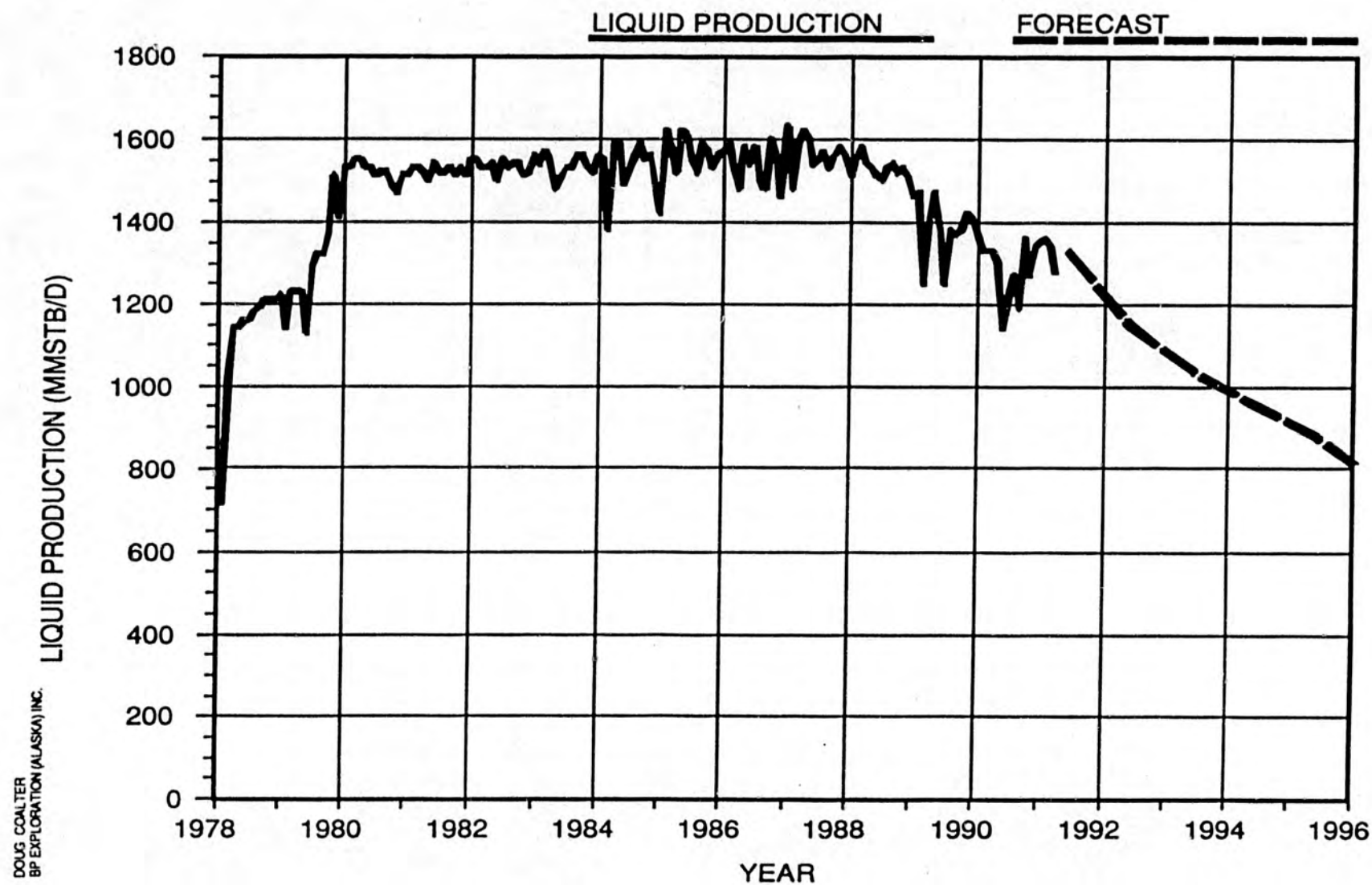
Prudhoe Bay Liquid Reserves

-  Remaining Oil in place
-  Reserves
-  Production



ALASKA STATE LEGISLATURE
PRUDHOE BAY RESERVOIR DEVELOPMENT AND MANAGEMENT

PRUDHOE BAY PRODUCTION



Development Philosophy

- **Continue to improve our understanding of the reservoir rock/fluids/processes**
- **Monitor reservoir performance**
- **Adapt Plan as appropriate in response to that performance**
- **Continue to assess new opportunities**
- **Field test as appropriate**
- **Provide for long-term flexibility for uncertainties, including gas sales**
- **Do not preclude gas sales**

Development Plan

- **Well stimulation/workovers**
- **Drilling**
- **GHX-2 project**
- **EOR expansions**

Development Plan

- **Drilling (250-400 additional wells)**
 - **Complete nominal 80-acre well development (1200 total wells)**
 - **Nonconventional (high angle) wells drilled to exploit thin oil columns**
 - **Peripheral waterflood area drilling**
 - **Waterflood pattern size reduction**
 - **40-acre development, potentially up to 100 forty-acre wells**
 - **Expected cost 1 - 1.5 billion (1991 \$)**
 - **EOR infill drilling**

Development Plan

- **GHX-2**
 - **Increase gas handling, processing, and injection from 5.3 to 7.5 BCFPD during 1994 and 1995 time frame**
 - **Apex gas injection starting in 1994**
 - **Expected rate increase 100 MBPD in 1995**
 - **Expected additional recovery 330-450 million barrels**
 - **Expected cost 1.4 billion ^{as spent} (1991 \$)**
1.3 - 1.5

Development Plan - EOR Expansions

- **PBMGP Areal Expansion**
 - **Doubles the size of the current flood**
 - **Over 60 new patterns**
 - **100 new wells**
 - **110 - 150 million barrels of additional reserves**
- **NWF₃ Infill Expansion**
 - **Infill current patterns to contact reservoir rock unswept by MI**
 - **24 New wells**
 - **40 - 70 million barrels of additional reserves**
- **Central gas facility expansions to increase miscible injectant supply to 700 million SCF per day**

Prudhoe Bay Development Plan Summary

- **Major Constituents:**
 - **Well stimulation/workover program**
 - **Drilling**
 - **GHX-2 project**
 - **EOR expansions**
- **\$3+ billion planned capital investments**
- **Recovery will approach or may even exceed 12 billion barrels of oil, about 2.5 billion barrels more than the original plan**
 - **Over half of this increase is the result of gas related projects**
- **EOR and Gas cycling processes will become the predominant recovery mechanisms in the future**
- **Production will decline an average of 8 - 10 percent per year over the next decade**
- **Does not preclude a major gas sale**

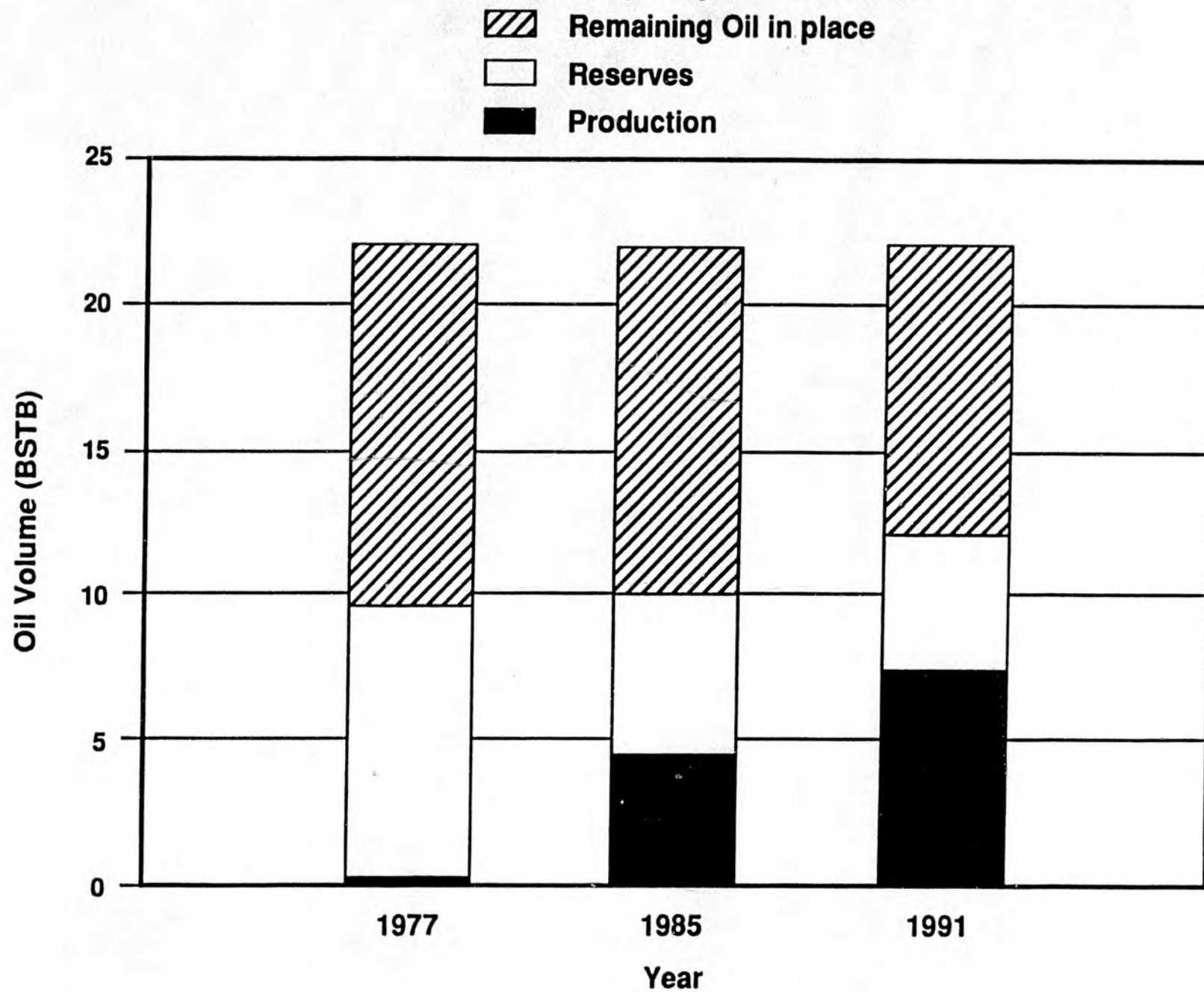
**ALASKA STATE LEGISLATURE
PRUDHOE BAY RESERVOIR DEVELOPMENT AND MANAGEMENT**

Resource Commitment

- **Three major owners actively participate in Prudhoe Bay reservoir development and management**
- **Over 500 petroleum professionals directly involved in field operations and development**
- **Extensive efforts in technology development and application**
 - **Access to worldwide technical expertise**
 - **State of the art technology applied in all aspects of reservoir development and management**

ALASKA STATE LEGISLATURE
PRUDHOE BAY RESERVOIR DEVELOPMENT AND MANAGEMENT

Prudhoe Bay Liquid Reserves



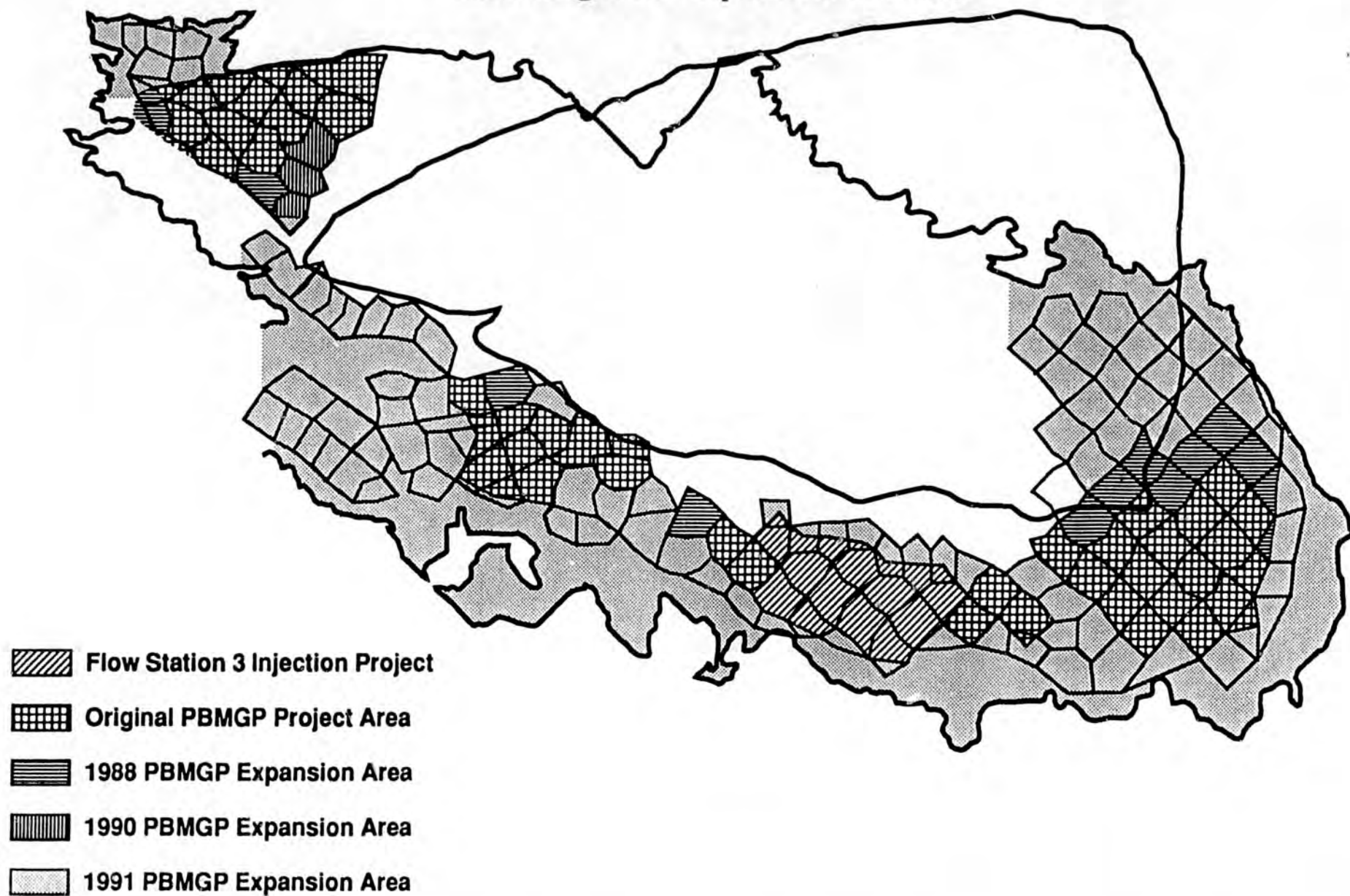
**AOGCC Hearing
Objectives**

- **Update of Prudhoe Bay development activities**
- **Approval of the areal expansion of the PBMGP**
- **Endorsement of the PBMGP expansion plans and NWFB Infill expansion project**
- **Approval of proposed amendment to PBMGP Conservation Order 195, Rule 2**

Prudhoe Bay EOR Development History

- **1982 Flow Station 3 injection project**
 - **11 patterns**
- **1984 original PBMGP**
 - **43 proposed patterns**
- **1986 Recertification of PBMGP**
 - **43 redefined patterns**
 - **Included 11 Sag River patterns**
- **1988 PBMGP expansion**
 - **Added 13 new patterns**
 - **Added 10 Sag River patterns to PBMGP, 9 to FS-3 IP**
- **1990 PBMGP expansion**
 - **Added 3 new patterns**
- **1991 PBMGP areal and NWFB infill expansions**
 - **AOGCC hearing**

Prudhoe Bay Miscible Gas Project Existing and Expansion Areas



PBMGP Conservation Order 195, Rule 2

- **Requires that the reservoir pressure in the PBMGP be maintained at or above an average of 3600 psi**
 - **Mandated to insure PBMGP miscibility**
- **Expected pressure decline is 30 psi/yr**
 - **Fuel gas**
 - **Oil production**
- **The PBMGP pressure is expected to decline to approximately 3100 psi by the end of project life**

PBMGP Conservation Order 195, Rule 2

- **Current development plan fully accommodates pressure decline, is prudent, avoids waste, and is expected to yield high recoveries**
- **Rule 2 not required for PBMGP miscibility**
 - **As reservoir pressure drops, C2 - C4 content in the MI must increase to maintain miscibility with the reservoir oil**
 - **CGF can make miscible injectant compositions that are miscible to reservoir pressures as low as 2000 psi**
- **Given the CGF's ability to manufacture a range of MI compositions, the appropriate reservoir management criterion is miscible injectant composition/miscibility and not a reservoir pressure limitation**
- **Such a miscibility criterion was requested from the Commission**

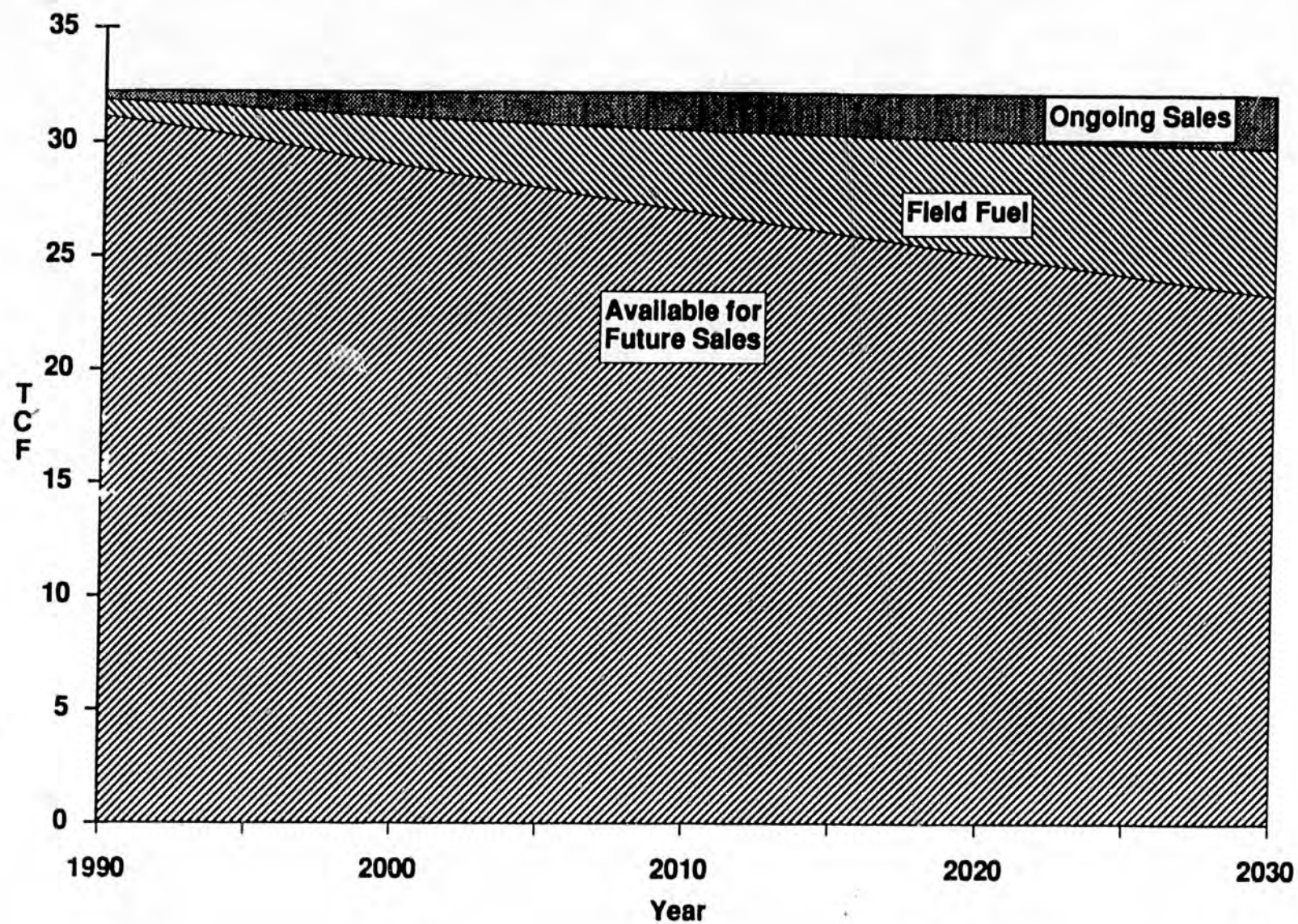
Major Gas Sales

Utilization of Gas Resource (Post GHX-2)

- **Natural Gas Liquids Sales:** 60,000+ barrels per day
- **Fuel:** 460 million SCF/day
Necessary for liquid production
- **Local Gas Sales:** 40 million SCF/day
- **Miscible Injectant:** Up to 700 million SCF/day
Yields 500+ million barrels of EOR oil reserves
- **Gas Cycling/Gravity Drainage:** 7.5 BCF/day field offtake
- **Gas Lift:** Up to 1.2 BCF/day
- **Field gas offtake and lift gas are integral to achieving total remaining liquid reserves of 4.4 billion barrels**

ALASKA STATE LEGISLATURE
PRUDHOE BAY RESERVOIR DEVELOPMENT AND MANAGEMENT

Disposition of Hydrocarbon Gas Resources



Major Gas Sales Key Assumptions

- **Gas Sales**
 - 2 BCF per day hydrocarbon gas delivered to market
 - 2.8 BCF per day hydrocarbon delivered to Gas Conditioning Plant
 - Rejected CO₂ returned to reservoir, resulting in net voidage due to sales of 2.4 BCF/D
 - Increases pressure decline to ~75 psi/yr
- **Reference Case (without Major Gas Sales)**
 - Maintain field gas offtake at level achieved with GHX-2 (7.5 BCF/D)
 - Waterflood/EOR patterns completed by 2015
 - Field viable down to a liquid production rate of 100 MSTB/D (until ~2030)
- **Field life highly sensitive to oil prices, tax and regulatory burdens, operating costs, and transportation costs**

Impact of Major Gas Sales

- **Major gas sales prior to waterflood/EOR completion (2015) do not permit simultaneous increase in field gas offtake**
 - **Continuing need for artificial lift prevails early in gas sales project**
 - **Deliverability (reservoir energy) of gas is limiting later**
- **Benefits of extensive field development activities implemented in 1990s to maximize liquid recovery are diminished with early major gas sales**

<u>Major Gas Sales Date</u>	<u>Incremental Recovery, STB</u>
2005	-0.4 billion
1997	-1.0 billion

Causes of Reserve Losses

Black Oil (~50%)

- **Reduction in well inflow performance increases significance of hydraulic limitations, leading to less optimal use of gas handling capacity**
- **Accelerated solution gas evolution decreases mobility of remaining oil**
- **Accelerated shrinkage of oil reduces effectiveness of drag oil mechanism**

Compositional (40-50%)

- **Ultimate gas throughput reduced**
- **Vaporization is more effective at higher pressures**

EOR (0-10%)

- **Need for richer MI reduces supply and potentially shortens project life**

Impact of Major Gas Sales

- **With major gas sales after waterflood/EOR completion (2015), existing facilities allow for increase in field gas offtake**
 - **Latent gas separation and dehydration capacity exists due to reduced need for artificial lift with waterflood abandonment**
- **Gas sales may support significant extension of field life, leading to higher ultimate liquid recovery than reference case (100-500 million STB)**
- **Key Uncertainties**
 - **Long term viability of TAPS**
 - **Economic viability of late life production**

Major Gas Sales

Summary

- **Later major gas sales from Prudhoe Bay increase ultimate hydrocarbon liquid recovery**
- **Any major gas sales strategy must consider the total hydrocarbon resource - both oil and gas**
- **Current development plan maximizes the in-field utility of the gas and does not preclude a major gas sale**

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

WALTER J. HICKEL, GOVERNOR

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2400
FACSIMILE: (907) 586-2754

January 22, 1992

JAN 22 1992

The Honorable Kay Brown
Alaska State Representative
P.O. Box V
Juneau, AK 99811

Dear Representative Brown:

Your note of January 8 to the House Finance Committee included two references I would like to comment on.

- "the production of several billion barrels of oil may be lost if gas sales begin prematurely without compensating measures."

Way over stated and entirely negative in perspective! By the later half of the 1990s (the earliest gas sales can start) there will remain about 2 billion barrels of oil to recover. A maximum change of 10-15% in that recovery might be attributed to leaving lower pressured oil in the reservoir because of greater voidage from gas sales. But, those pressure effects can be mitigated through water injection.

Gas sales will increase the oil production rate and increase recovery of all the gas liquids. Gas sales will also have a positive impact on Prudhoe Bay's field life, which is the major determinant of ultimate recovery.

I agree that the inter-action of gas sales and oil production is a vital issue to be considered during the State's royalty gas sales decision process, but I start from a view that this issue is not a major negative or positive impact.

- "DNR Commissioner Heinze . . . intends to move quickly as possible to sell Prudhoe Bay royalty gas in the Asian market."

I intend at the oversight hearing tomorrow to present my recommendation to use the State's Prudhoe Bay royalty gas to "test" all potential gas markets (including Asia). The proposed RFP would be worked through the multi-year/multi-step regulatory process already in place with legislative and Royalty Board approval decision points.

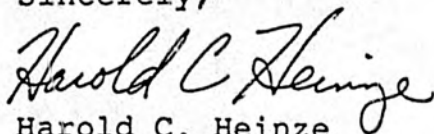
Representative Brown

- 2 -

January 22, 1992

I believe it will take a positive attitude on all our parts if we are to fully understand and achieve the significant potential benefits from North Slope gas sales.

Sincerely,

A handwritten signature in cursive script, reading "Harold C. Heinze".

Harold C. Heinze
Commissioner

cc: Paul Fuhs, Legislative Liaison
Office of the Governor

STATE OF ALASKA

DEPT. OF NATURAL RESOURCES**DIVISION OF OIL AND GAS****WALTER J. HICKEL, GOVERNOR**P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

(907) 762-2547

January 22, 1992

The Honorable Kay Brown
Alaska State Legislature
P. O. Box V
Juneau, Alaska 99811

Dear Representative Brown:

I apologize for the delay in responding to your inquiry of January 2, 1992 regarding the personnel and budgetary requirements entailed to develop a reservoir model capable of evaluating Prudhoe Bay reservoir performance under a variety of depletion scenarios. However, because of the inherent complexity of such analyses, I thought that it was important to provide you with the independent assessments of the two consultants who advised the division in its recent appearance before the Alaska Oil and Gas Conservation Commission (AOGCC). I have enclosed copies of the responses which we received from Messrs. H.K. van Poolen and Allan Spivak for your review.

I share your personal concern for the proper management of the State's royalty share of oil and gas from the Prudhoe Bay Unit. In fact, that concern was the primary motivation for the division's participation in the hearings before the AOGCC in response to the producers' petition to expand the Prudhoe Bay Miscible Gas Project (PBMGP).

Because of the costs associated with independently replicating the extensive modelling efforts of the producers, I agree with the conclusions of Mr. van Poolen -- that it would be both more efficient and cost-effective to independently analyze the models which have been developed by the producers. As we have discussed previously, however, this presumes a willingness on the producers part to share those data with the division and its consultants, either directly or through the AOGCC, as we urged in the recent hearings.

As you will see from your review of van Poolen and Spivak's responses, the estimated costs of independently modelling the Prudhoe Bay reservoir performance could run in the millions of dollars, and would require a minimum of two years. I personally believe this to be an

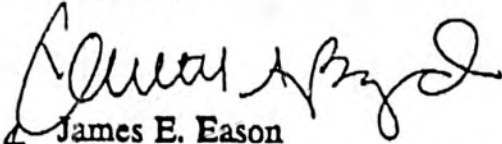
The Honorable Kay Brown

January 22, 1992

Page 2

optimistic estimate, particularly as it relates to the time required. Alternatively, if we are successful in convincing the producers to share their models with us, our costs would be reduced dramatically, ranging perhaps from \$.5 to \$1.0 million. More importantly, the analyses would be available in a much more timely fashion, thus increasing the utility of the information in the State's management of its oil and gas resources.

Sincerely,



James E. Eason
Director

Enclosures

cc: Harold C. Heinze - Commissioner
Bill Van Dyke

PB.ReservoirModel.KB.txt

INTERA WEST

environmental consultants

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January 6, 1992

Mike Kotowski
State of Alaska
Department of Natural Resources
Division of Oil and Gas
P.O. Box 107034
Anchorage, Alaska 99501

RECEIVED
JAN - 6 1992
DIV. OF OIL & GAS

Dear Mike:

This letter is in response to your inquiry today regarding a model of the Prudhoe Bay reservoir. I am assuming that the purpose of such a model would be to serve as a check on forecasts presented by the operating companies and to answer some of the "big picture" questions that were raised at the recent AOGCC hearings. Examples of such questions are:

- what is the effect of gas cap gas sales on liquids recovery?
- what is the effect of an unanticipated pressure drop on the recovery efficiency of the miscible project(s)?
- what is the effect of injecting gases such as nitrogen or carbon dioxide into the gas cap?
- what are the projected oil and gas production rates for alternative reservoir management scenarios?

Due to the importance of the Prudhoe Bay reservoir to the operating companies, they have expended considerable effort in applying state-of-the-art technology to construct their reservoir models. In order to engage in meaningful dialogue with the operating companies with regard to their reservoir model results, it would be necessary to employ similar technology. This means a compositional simulator with 10,000 to 100,000 grid blocks. This would preclude resurrection of the previous Van Poolen model since it was not compositional and since the simulator used for these previous studies is at least one, and maybe two generations out of date.

It is obviously impossible to come up with a precise cost estimate without an outline of the objectives of the studies to be performed and without a detailed work statement. Notwithstanding this, the minimal effort to set up a state-of-the-art model of Prudhoe Bay would require several person-years of effort plus related software and computer hardware costs. A

considerable portion of the effort would involve processing geologic data to properly characterize the reservoir and history matching past performance.

To give you an idea of the minimal cost and timing, it can be assumed that the equivalent of three person-years of work would be required at a total cost of about \$500,000. (The actual number of persons would probably be more than three and would be a mix of senior engineers, technicians and various levels of personnel between the two). In addition, the software and hardware costs would be on the order of an additional \$100,000 for a total minimum cost of \$600,000.

The elapsed time to set the model up and check it out would be about a year. Even if a concentrated effort were made to accomplish this work in the shortest possible time, the size of the reservoir and the amount of data to be processed would make it difficult to construct the model in less than one year.

You can probably tell by the "roundness" of the above numbers that this is a very rough estimate but, hopefully, it will give you an idea of the amount of effort and related costs that would be involved in constructing a simulation model of the Prudhoe Bay reservoir. You should also be aware that, due to the complexity of the model, running individual cases would not be trivial and it could take a week to make a single run and to analyze the results of that run.

I hope that this brief analysis is of some help. Please do not hesitate to call me if you have any questions or if you would like me to attempt a more detailed cost estimate based on a work statement that we jointly put together.

Yours very truly,

A. Spivak

Allan Spivak

INTERWEST

H.K. VAN POOLLEN

55478 HIGHWAY 285
P.O. BOX 121
SHAWNEE, COLORADO 80475
TELEPHONE 303-838-7168

RECEIVED

JAN 15 1991

DIV. OF OIL & GAS

January 9, 1992

Mr. Michael D. Kotowski
Petroleum Engineer
State of Alaska
Dept. of Natural Resources
Division of Oil and Gas

Dear Mike,

Following your request of yesterday I wish to make a number of comments relative to modeling the Prudhoe Bay Field. During the seventies and early eighties I was involved in modeling the Prudhoe Bay Field. These studies were made on behalve of the State of Alaska Division of Oil and Gas, which is now the Alaska Oil and Gas Conservation Commission. A rather large effort, i.e., a full fledged three-dimensional study, was made with both moral and financial support of the State Legislature. All of these studies were aimed at gross reservoir behavior. These studies had to answer questions such as EFFECTIVENESS OF THE AQUIFER, EFFECT OF GAS SALES ON ULTIMATE RECOVERY, EFFECT OF PRESSURE MAINTENANCE BY MEANS OF REINJECTING PRODUCED GAS AND WATER ON ULTIMATE RECOVERY, AND THE EFFECT OF SOURCE WATER (Arctic Ocean) ON ULTIMATE RECOVERY. In making these studies the State was in a better position to request results of studies by the Operators, the State was in a better position to evaluate these results, and the State (through the Alaska Oil and Gas Conservation Commission) was in a better position to approve operational requests by the Operators.

The software used for these studies was essentially a Black Oil Modeling Program, which means it basically dealt with only three components, i.e. oil, gas and water. The latest version of this program used in these studies is available at the AOGCC.

It should be emphasized that considerable time and effort went into basic data preparation for these studies. A total estimated time for data preparation was 15 man-years with personnel from both my company and the AOGCC. Where the questions to be answered were gross in nature the model could be fairly coarse. Such coarseness allowed for shorter computer times and more generalization of geological data.

During the last eight or so years the emphasis of model studies has drastically changed. Present questions to be answered by the studies is directed toward MISCIBLE INJECTANTS and DROPOUT OR VAPORIZATION OF CONDENSATE IN THE GASCAP, and therefore multicomponent systems. That means that a compositional model program is required which entails many more complexities. Also it requires a finer grid. The purchase of such a program and peripheral programs will have an estimated cost of a quarter million dollars. Computer time to make runs will be very costly and for a single study will equal the cost of the program. The input data will have to be obtained from various laboratory data obtained by the Operators. These data may not necessarily be part of the public domain. After one gets the data they will have

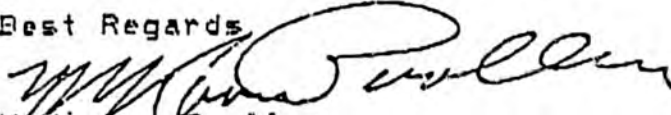
to be checked against equation of state programs. This kind of analyses can easily absorb a man year. Besides the fluid analyses, the geological and well completion data over the last ten to twelve years will have to be brought up to date. I can foresee an overall effort to take twenty man-years over a two year period. That way one may look at a cost on the order of several million dollars.

The problem with this approach is that answers would become available at too late a date. If the answers agree with those of the Operators, not much action is required. If the answers do not agree we would have to enter into a major argument with the Operators which might well be futile in the light of the efforts the Operators have put into these issues.

A MUCH BETTER APPROACH would be for the State to maintain a policing power over the Operators. The only way to maintain such power is to keep Rule 2 but to modify 3600 psi to 3500 psi. At the same time the State should get excess to all laboratory work, and mathematical model studies performed by the Operators, which led to their conclusions and requests. The State should retain a knowledgeable consultant, familiar with the Prudhoe Bay Field, to assist State Petroleum Engineers in the gathering of reports, their analyses and recommendations to the final authority who approves the Operators requests. The cost for such an outside contract should be less than one hundred thousand dollars for the first year and much less thereafter. The State should dedicate at least one of its Petroleum Engineers on a full-time basis.

ALLOWING MODIFICATION OF RULE 2 WILL ALLOW THE OPERATORS TO DO WITH THE FIELD WHATEVER THEY WANT. The present Operators are doing a good job in general. But what will happen if they sold their interest. Then it might be too late for the State to play technical catchup.

Best Regards



H.K. van Poolen

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

WALTER J. HICKEL, GOVERNOR

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2400
FACSIMILE: (907) 586-2754

January 21, 1992

OFFICE OF THE COMMISSIONER

The Honorable Mike Navarre
Alaska State Representative
P.O. Box V
Juneau, AK 99811

Dear Representative Navarre:

Pardon the delay in answering your question on the potential revenue impact of North Slope gas sales, but it just took a while to get in front of me.

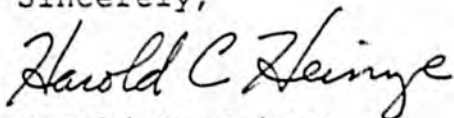
In thinking about the benefits to the State of Alaska in bringing its 3+ TCF of Prudhoe Bay royalty gas to market I have used a range of possible values that looks like this.

<u>Wellhead Gas Price</u>	<u>Daily Sales Volume</u>	<u>State Share</u>	<u>Annual State Revenue</u>
\$.50/MSCF	1.5 BSCFPD	1/8	\$35MM/YR
1.00	2.0	1/5	150
1.50	2.5	1/3	450

The wellhead gas price will remain an item of conjecture until the market is given a chance to speak and will vary over time as other energy prices (predominately oil price) vary. The wellhead gas price is also determined by transportation costs which are driven by construction and operating costs, financing, and throughput volume. The State of Alaska's revenue share may range from a royalty share of 1/8 to an effective 1/3 share based on royalty, severance tax, and corporate income tax elements. Additional revenue to the State results from taxes on the gas production facilities, the investment and profitability of the gas transportation system, and the jobs and general economic increases attributable to the sale of North Slope gas.

I feel that the potential reward of North Slope gas sales is much larger than any other opportunity Alaska has (with the exception of ANWR). I am recommending we proceed down the multi-year/multi-step royalty gas sales regulatory process to fully understand and achieve these significant potential benefits.

Sincerely,



Harold C. Heinze
Commissioner

Representative Navarre

- 2 -

January 21, 1992

cc: Paul Fuhs, Legislative Liaison
Office of the Governor

The company now says just 31 barrels were lost. There are 42 gallons of oil to the barrel.

As recently as two weeks ago, pipeline manager Bob Williams said as much as 171

frozen pipe burst.

The release was estimated at 1,006 barrels of an oil and water mixture.

The National Oceanic and Atmospheric Administration said that about 40 percent of the oil had been recovered.

very rough estimate, and Kenai Pipe Line agreed.

But DEC environmental specialist Mark Sienkiewicz said Tuesday the agency now thinks only about 16 barrels of oil were picked up

That's 672 gallons.

The agency arrived at the figure after heating the collected oil and water mixture to separate the oil from the water.

Williams said demanding news organizations had

at which enormous quantities of oil were released.

A first guess of the spill's size had been as much as 400 barrels, which is roughly 17,000 gallons.

That would have made it

Please see Page B-3, SPILL

c staff, directors els of fired chief

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To	Rep. Kay Brown
Co.	Jeff Lawrence
Dept.	VPC
Fax #	465-2278
Phone #	265-3180

Hickel plans to test market for gas

Administration forges ahead despite pipeline setback, industry reluctance

By GEORGE FROST
Daily News reporter

The administration of Gov. Wally Hickel said it will announce today a plan to sell state-owned natural gas from the Prudhoe Bay oil field.

Harold Heinze, commissioner of natural resources, said his plan is to "test all potential gas markets, including Asia," with the state's share of the 30 trillion cubic foot bubble atop the field, the largest in North America. The state of Alaska owns one-eighth of the gas at Prudhoe Bay.

He made the statement in a letter Wednesday to Rep. Kay Brown, D-Anchorage. Heinze did not return telephone calls to discuss his idea and the letter provided few details, but it did say Heinze will discuss the plan today at a joint hearing of the House finance and oil and gas committees.

The plan comes as a surprise to state regulators who must approve or deny it.

"This is all news to me. I don't know what he is saying there," said Dave Johnston, chairman of the Alaska Oil and Gas Conservation Commission, the state agency with the authority to approve

or deny gas sales on the North Slope.

"It sounds like possibly he may be trying to do a gas sale. Or he may be trying to float royalty balloons."

As both private entrepreneur and as governor, Hickel has been the biggest promoter of building an 800-mile gas pipeline from Prudhoe Bay to Valdez, where the gas would be turned into a liquid and exported to Asia. Last month, the governor settled an ethics complaint from a special prosecutor by giving away his stock in Yukon Pacific, the company he founded in the early 1980s to build the gasline. The project has been stymied by the reluctance of the North Slope oil companies to sell gas, and by the reluctance of Japan, Korea and Taiwan to buy it.

Neither Arco Alaska nor BP Exploration (Alaska) — the two biggest North Slope operators — could be reached for comment late Wednesday, but both companies have said recently they don't want to sell any Prudhoe Bay gas before the year 2005, while the Hickel administration has been pushing for sales in the late 1990s.

The oil companies say they

need the gas to inject into the reservoir to maintain pressure to pump oil. Gas is also increasingly used as a oil-dissolving solvent that over the life of the field will free up hundreds of millions of barrels of otherwise unrecoverable crude oil.

In his letter, however, Heinze maintains that selling gas would not substantially hurt oil production. He said that, by the late 1990s, "the earliest gas sales can start," about 2 billion barrels of recoverable oil will remain in Prudhoe Bay. As a result of gas sales, up to 15 percent of that oil might be lost due to "leaving lower pressured oil in the reservoir," he wrote.

Heinze said the pressure loss could be partially made up by flooding the reservoir with water. He said gas sales ultimately would increase the recovery of oil and gas by prolonging the life of the field.

Johnston said the three-member oil and gas conservation commission may schedule public hearings to consider the proposal. He said he doubted selling the state's one-eighth royalty share of the Prudhoe gas would in itself be enough to get the project going.

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ALASKA AND BP - A SHARED FUTURE

Testimony of BP Exploration (Alaska) Inc. to the House Special Oil & Gas Committee

By Brian E. Davies
Vice President

March 20, 1992

Mr. Chairman, Members of the Committee. Good afternoon. My name is Brian Davies and I am Vice President for Endicott and Development Projects for BP Exploration (Alaska) Inc. My testimony today will share with you some thoughts about the outlook for Alaska as BP sees it, and our plans to remain a major player in Alaska.

In the process, I hope to debunk thoroughly a number of rumors about BP that have persisted for some time -- rumors, for example, that we are turning over our operatorship at Prudhoe Bay to ARCO, that BP is shifting emphasis from Alaska to new areas overseas such as Colombia, even that BP is leaving Alaska and has quietly put its Alaskan assets up for sale. None of these rumors is true. Indeed, they could hardly be more mistaken about our intentions. As you will see, the strongest and best demonstrations of BP's continuing Alaskan commitment have been misconstrued as evidence of an intent to abandon this state.

Let me begin by reminding everyone that BP has been and remains the largest investor in Alaska by far. We own, and have paid for, just over half of the investment in the main oil reservoir at Prudhoe Bay -- which is not only the largest oil field in North America, but also required the greatest investment to develop. We own, and have paid for, more than half of the investment in Endicott. We own, and have paid for, half of the investment in the Trans Alaska Pipeline System. We own, and have paid for, approximately 40% of the investment in the Kuparuk River field, currently the second largest oil producer in the United States. We have assembled the greatest fleet of Jones Act ships in history to transport our Alaskan oil. But unlike our partners on the North Slope, we are barred by the Jones Act from owning any of these ships.

Here is a table showing how much money BP has spent for Alaskan projects during the last decade.

<u>Year</u>	<u>BP's Alaskan Spending</u>	<u>Alaska Royalty and Taxes Paid</u>
1982	3.1	1.7
1983	1.9	1.4
1984	1.9	1.5
1985	1.8	1.6
1986	1.5	0.7
1987	1.1	1.1
1988	1.1	0.9
1989	1.4	1.1
1990	1.5	1.8
1991	<u>1.5</u>	<u>1.2</u>
Total	16.8	13.0

Figure 1. BP's Historic Spending on Alaskan Projects (\$ billions)

As you see, in the past ten years BP **alone** has spent some \$16.8 billion -- an average of nearly one and a half billion dollars a year. These expenditures have enabled BP to become and remain the largest producer of oil in Alaska. They have also made us the State's largest taxpayer -- a distinction we did not actively seek, but one which we acknowledge and accept. The table shows that we have paid some \$13 billion in Alaskan taxes and royalties since 1982.

Today our commitment to Alaska remains as strong as ever. This year BP again plans to spend on the order of one and a half billion dollars in developing and operating our Alaskan assets. To those who fear BP may forsake Alaska in favor of Colombia, let me put this into perspective: Our planned spending on Alaska is over **seven times** what we plan to spend on Colombia this year. And we have committed ourselves to the GHX2 gas handling project for Prudhoe Bay -- a one and a half billion dollar investment, of which we are paying half. Clearly we would not continue investing heavily in Alaska if it were not important to us. The sheer size of our ongoing investment is proof of just **how** important it is.

Well, so much for the past and the present. What about the future? How does Alaska figure in BP's longer term plans?

The short answer is, Alaska figures very large indeed.

As some of you may already know, for several years BP has been actively divesting a number of its oil and gas interests that do not fit within our strategic, long-range plans. Our purpose is to focus on those assets that are truly "core" assets for our future business. We have, for example, sold our interests in onshore properties in the Lower 48 principally because they were too small and too numerous and tended to distract us from effectively managing our major properties. BP's Alaskan interests are definitely part of our "core" both because of their present size and because of their potential for the future.

Let me briefly explain why Alaska is part of BP's "core" portfolio. For those of us in the "upstream," or exploration and production side of BP's business, the challenge is not only to produce the reserves we already have, but we must also look continually to find new reserves to replace what we are producing.

To clarify my point I will use the term "**resource**" to mean the total amount of oil or gas that is in place, without regard to how much of it might ever be recovered. In contrast, I will use the term "**reserves**" to mean that portion of the resource in place which we believe can ultimately be produced using existing technology and under reasonable economic conditions.

In the case of Prudhoe Bay, for example, the amount of oil originally in place in the ground was some 22 billion barrels. Of this, some 9.6 billion barrels were seen as being recoverable when the field began producing. In other words, the oil **resource** was 22 billion barrels and the **reserves** in 1977 were 9.6 billion barrels. Since then some 8 billion barrels of oil have been produced, leaving a remaining **resource** of 14 billion barrels -- 22 billion originally in place minus the 8 billion that have come out. Similarly, the remaining **reserves** of the field would be 1.6 billion - 9.6 billion minus the 8 billion already produced.

But the remaining reserves at Prudhoe Bay are much greater than 1.6 billion barrels. What has happened is, we and our partners in the Prudhoe Bay field have been able to convert more of the **resource** into **reserves**. Instead of 9.6 billion barrels of recovery, we have managed and developed the reservoir in such a way that we now see technologically feasible ways of recovering 12 billion barrels or more, assuming economic conditions remain reasonable. In other words, some 2.4 billion barrels of oil have been converted from mere **resource** into **reserves** since 1977. And consequently the remaining reserves are not 1.6 billion barrels, but a whopping 4 billion barrels -- which still makes Prudhoe Bay the largest oil field in the United States even after 15 years of production.

Here is a table that summarizes the arithmetic I have just gone through.

	Resource	Reserves
Estimated as of 1977	22	9.6
Additional Reserves from Resource		<u>2.4</u>
		12.0
1977-91 Production	<u>8</u>	<u>8.0</u>
Remaining as of 1992	14	4.0

Figure 2. Oil Resource and Reserves of Prudhoe Bay

In terms of recoverable **reserves**, the additions to Prudhoe Bay since 1977 are greater than the total oil reserves for Kuparuk, and more than twice as great as the oil reserves of Endicott, Lisburne, Point McIntyre, Niakuk and Milne Point combined. In fact, nowhere else in the world during the past decade has BP been more successful in adding **reserves** of oil to its inventory than on the North Slope.

So now you know where one of BP's major focuses has been in terms of looking for new **reserves**. We have been looking right in our own back yard -- at

the substantial **resources** that have already been discovered -- to try to figure out how we convert even more of the **resource** into recoverable **reserves**. And we will continue these conversion efforts. After all, even with 12 billion barrels of **reserves**, there are still some 10 billion barrels of **resource** there for us to work on. This is why BP views Alaska as part of the "core" for its future business.

Besides exploring for ways to convert **resources** into **reserves**, BP is actively doing conventional exploration work on the Slope as well.

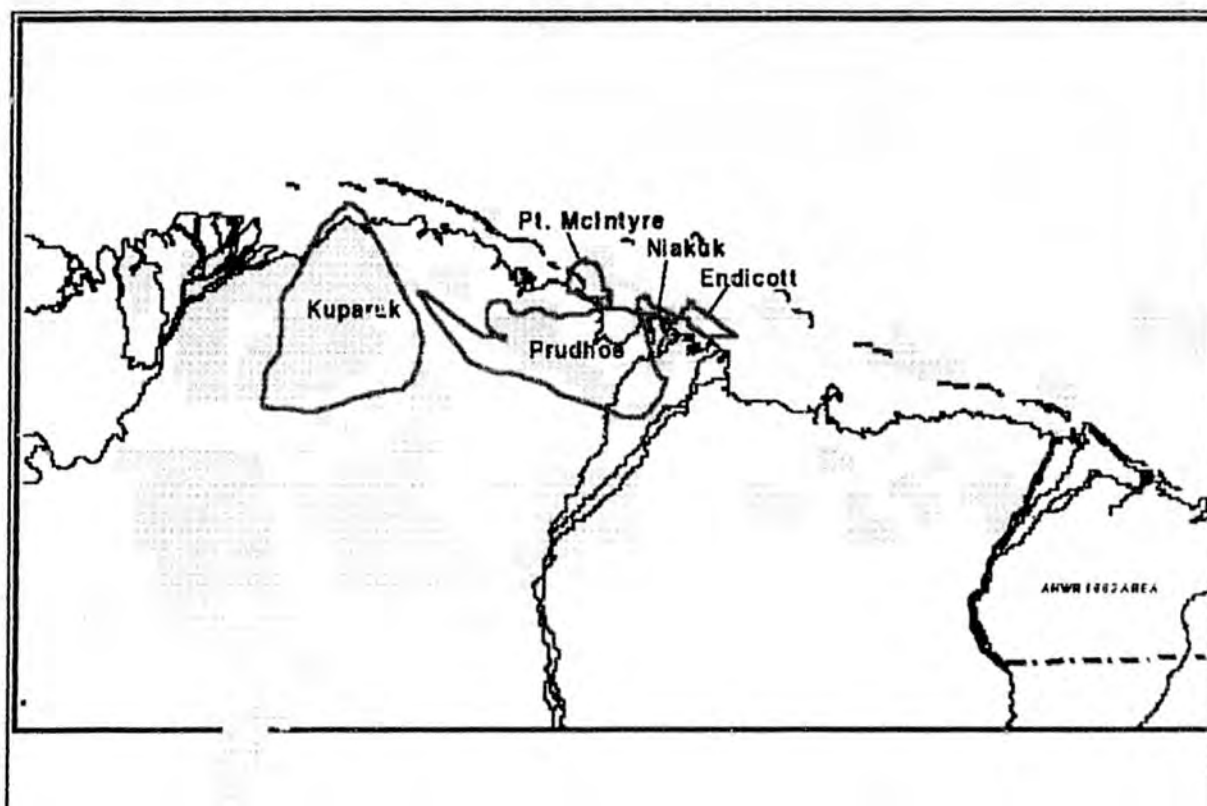


Figure 3. Map of BP's North Slope Leases

Here is a map showing acreage on the North Slope in which BP owns a leasehold interest. Note the land outside the producing limits of the fields currently in production. As you can see, BP's position onshore in the Central North Slope is a dominant one.

Why are we focused there? We are, quite simply, looking for oil that is close to TAPS. Any oil we find there should not only cost less to move to the pipeline, but its nearness to the pipeline should also allow it to come into production much sooner than if it were farther away. In addition, we are looking for oil in and around the edges of the already developed fields. As production from the fields declines, there will be unused capacity in their facilities that could be used for any new oil we may find. Using existing production facilities instead of designing and installing brand new facilities will reduce the costs of producing the new oil, and thus will lower the size of discovery that has to be made in order to be economic.

You may have heard that BP recently decided not to participate in the Kuvlum well in deeper water of the Beaufort Sea, and people in some quarters have taken this as a sign of BP's lack of commitment to Alaska. But let me say here and on the record that BP withdrew from Kuvlum because it does not fit with our strategy and position on the North Slope. As you can see from where we own leases, our focus is overwhelmingly onshore and in shallow waters fairly close to shore. With Endicott we have become the technological leader for small-footprint developments onshore or on an island in shallow waters.

But Kuvlum would be something very different. Even if a major oil discovery were made, Kuvlum is far enough offshore that its development would require solutions to such major problems as moving pack ice, installing production facilities in such seas in more than 100 feet of water, and developing a way to bring the production to shore. We considered becoming the pioneer in advancing the technology that would be needed to overcome these problems, and we found that we would have little further use for the new expertise and knowledge we would gain. We simply don't have other acreage where we could apply that technology. So we decided to let those explore and develop Kuvlum for whom it will be a better fit.

Meanwhile, we will continue to explore those prospects that do fit with our position and strategy. This year alone we plan exploration efforts on our acreage at a likely cost of more than \$20 million. The two or three exploratory wells we plan for this year are right in line with the historic rate of exploratory wells in which we participated during the past decade, which averaged 2.4 wells per year.

I would like to talk now about the decline in Prudhoe Bay production, for it is forcing us to take various measures that have led to the greatest misunderstanding about our long term intentions for Alaska.

Prudhoe Bay is in decline. It has been since 1988. More important, it will continue to decline, significantly, over the coming years. And as production declines, so do revenues -- both our revenues and the State's.

Julian Darley, President of BP Exploration (Alaska), described the "new economic order" on the North Slope very clearly last January during an address at the "Meet Alaska '92" forum put on by The Support Industry Alliance.

Here is a simplified illustration of the production and revenues from Prudhoe Bay.

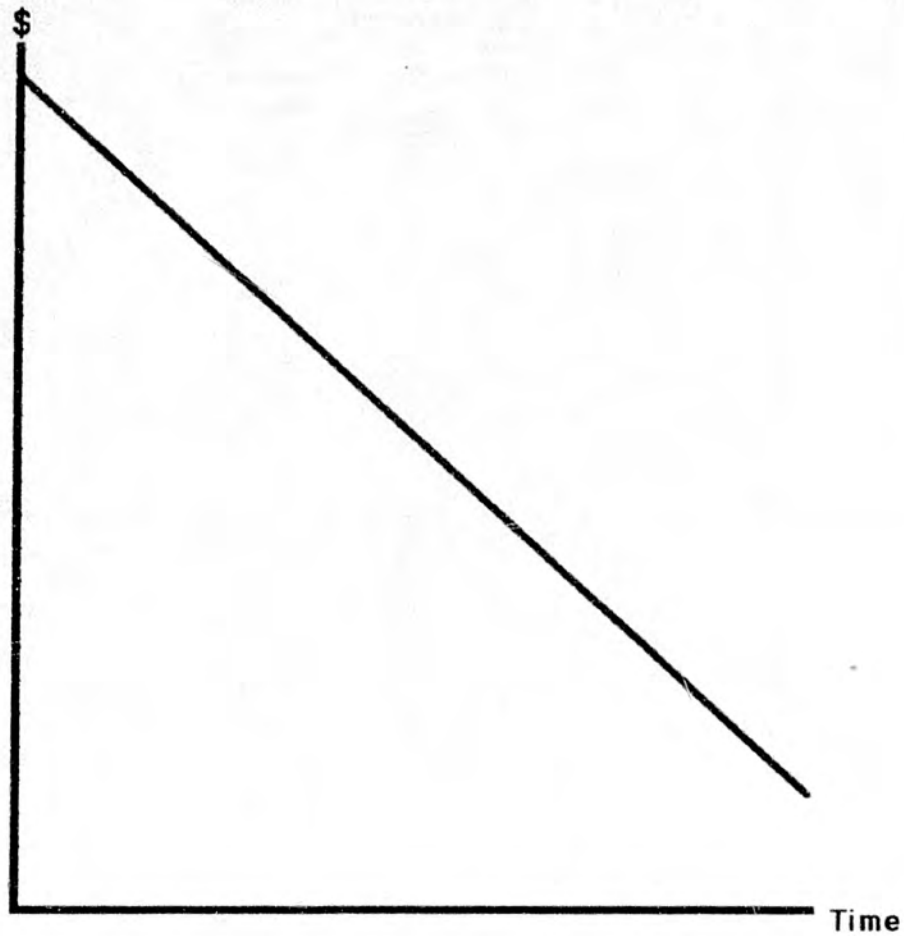


Figure 4. Illustration of Oil Production Decline

This illustrates the fact that oil production is in decline. This is the part of the picture the State sees, since state royalty and production tax revenues depend on the price of oil and the volume being produced.

But there is another side of the economic picture that we, as a working interest owner in the fields, are seeing. This is the cost side of the ledger.

Here is a simplified illustration of the costs of operating the field, based on historic experience.

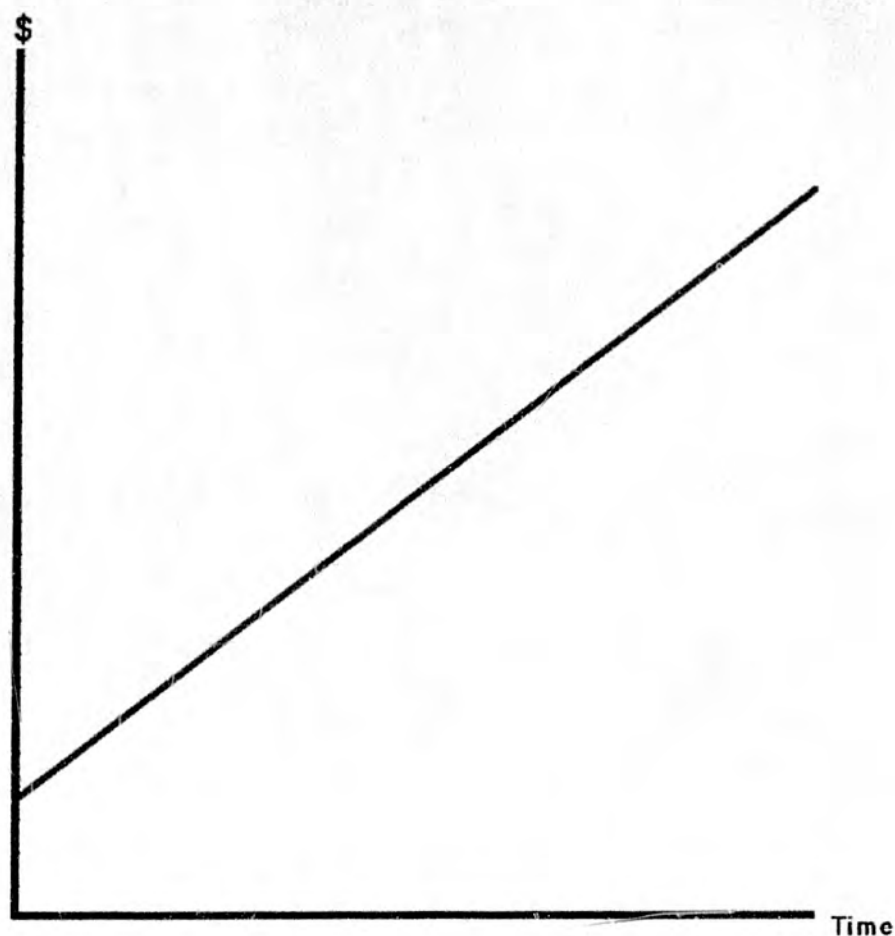


Figure 5. Illustration of Increasing Operating Costs

As this illustration suggests, costs have been rising. And we expect them to continue to rise because the industrial challenge is increasing. Although less oil is being produced, more and more gas and water have to be handled in operating the field.

This side of the economic picture is largely invisible to the State -- particularly in terms of its petroleum revenue -- because the production tax and royalty revenues are based on the so-called "wellhead value" of the oil and are not affected by the costs of producing that oil.

Now here is an illustration of what the complete economic picture looks like when you put the production and the cost trends together.

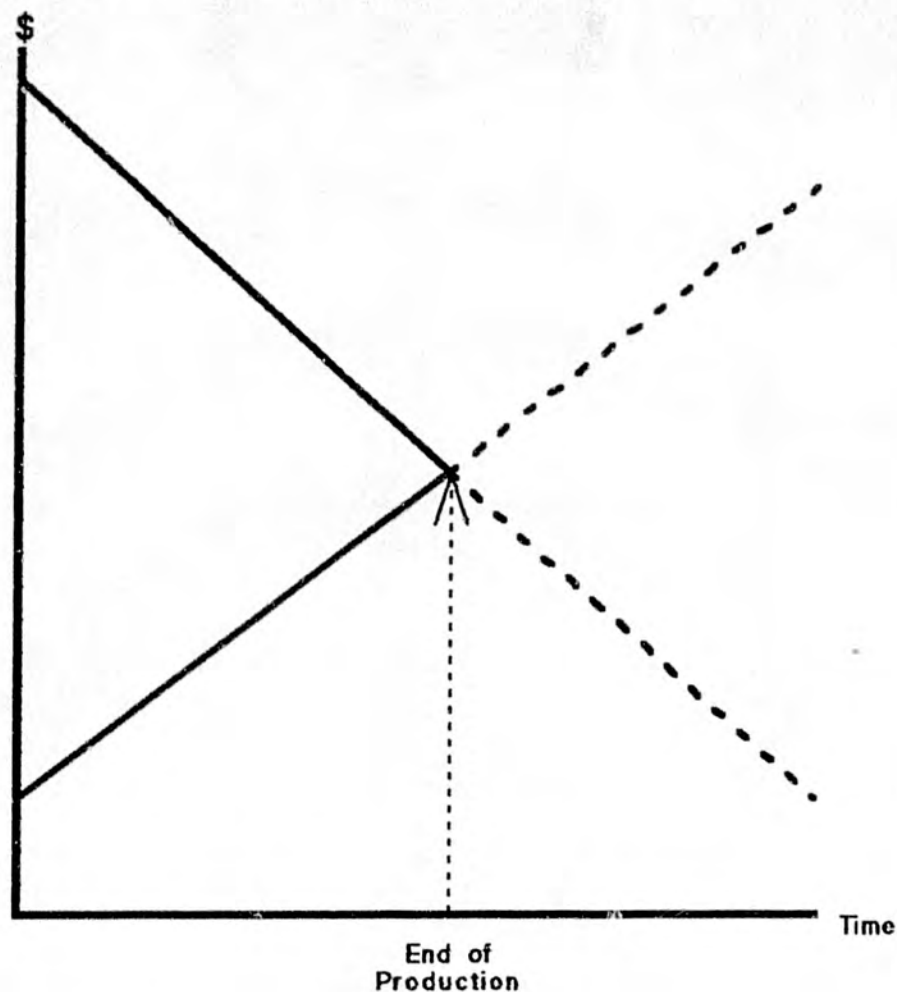


Figure 6. Effect of Rising Costs and Declining Production

Yes, that's right, production stops and the field dies. When the operating costs of production overtake the revenues from that production, it makes no sense to continue operating the field. So it gets shut down. This is what happened with the two platforms in Cook Inlet that have been shut down in the past year. Eventually this is the ultimate destiny of every oil field — or of any mine or other activity that draws against a depleting, finite resource.

With this prospect staring us in the face at Prudhoe Bay, what can be done about it? One potential solution would be to reverse the downward trend in revenues, as the next slide illustrates.

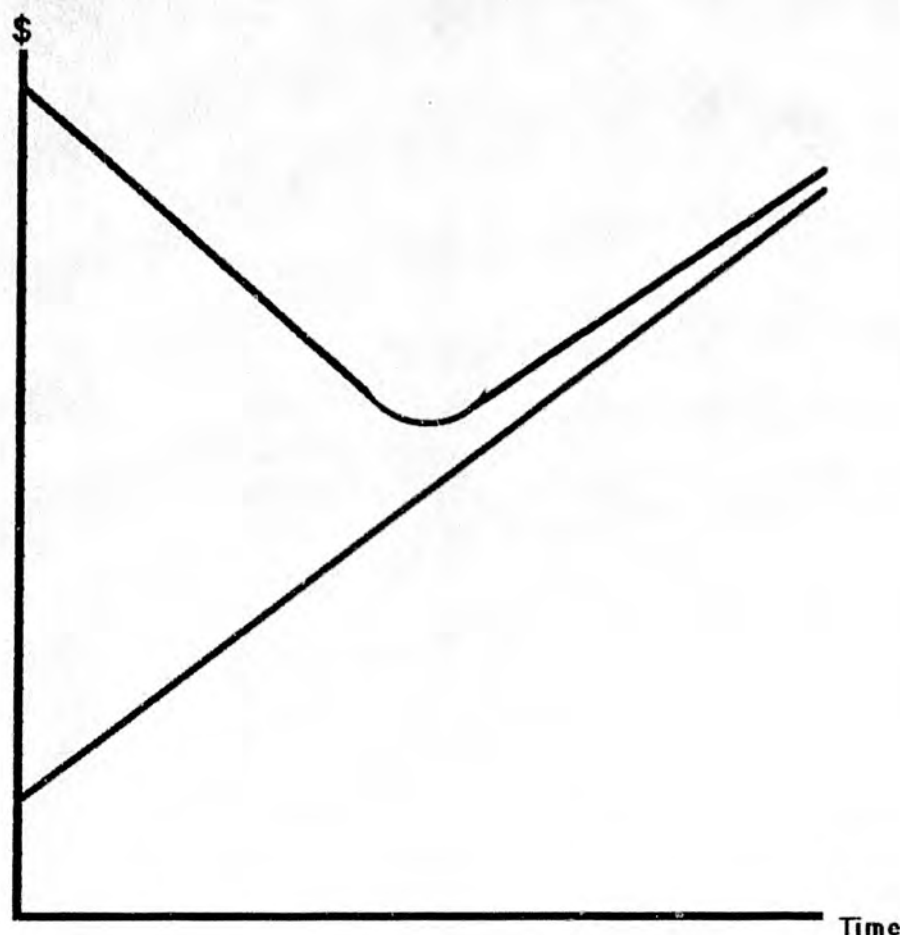


Figure 7. Effect of Reversing the Revenue Decline

But is this solution realistic? What would have to be done to make it come true?

To increase the revenues, there must be either an increase in prices or an increase in production, or an increase in both. There is, of course, one small practical problem with repeatedly raising oil prices enough to put revenues back on an increasing path and keeping them there. That problem is the market. Oil producers have to take the price the market offers, and cannot dictate prices to the market. In the early '80s even OPEC discovered that it could not ignore the laws of the market and raise oil prices indefinitely. Following the massive price increases of the 1970s, oil consumption dropped, and at the same time new supplies of oil were becoming available because OPEC's high prices had made them economic for the first time. In the end these market forces meant that OPEC members could not sell as much oil as they wanted to, and the effectiveness of the cartel finally collapsed in 1986 as the result of competition among its members.

What about increasing revenues by increasing production? Well, almost by definition, the fact that Prudhoe Bay is in decline means that production cannot be

increased. Instead it steadily decreases. But this does not mean there is nothing to be done on the production side of the equation.

For, in fact, we can do things about the **rate** of decline. Even though we can not reverse the decline in production, we can slow it down. And this is what we have been doing. For example, last year's program of well fracking, workovers and other activities to stimulate production from existing wells succeeded in slowing the rate of decline by an average of 126,000 barrels a day from what it otherwise would have been. In addition, because the GHX1 gas handling expansion project was on line during the entire year, total production of hydrocarbon liquids from Prudhoe Bay in 1991 stayed almost exactly even with 1990.

This temporary arrest of the decline in production during 1991 was a tremendous achievement, if we may say so ourselves. But it did not come cheaply. We and the other Prudhoe Bay owners spent over \$225 million in 1991 doing frac work and well workovers. The GHX1 project cost \$400 million. The point is this -- **slowing down the production decline requires a lot of new investment.**

While it costs a lot to slow down the decline, BP believes there are numerous new investment opportunities that will prove worthwhile. Here is a graph illustrating how the decline in North Slope production can be slowed down by new capital investments.

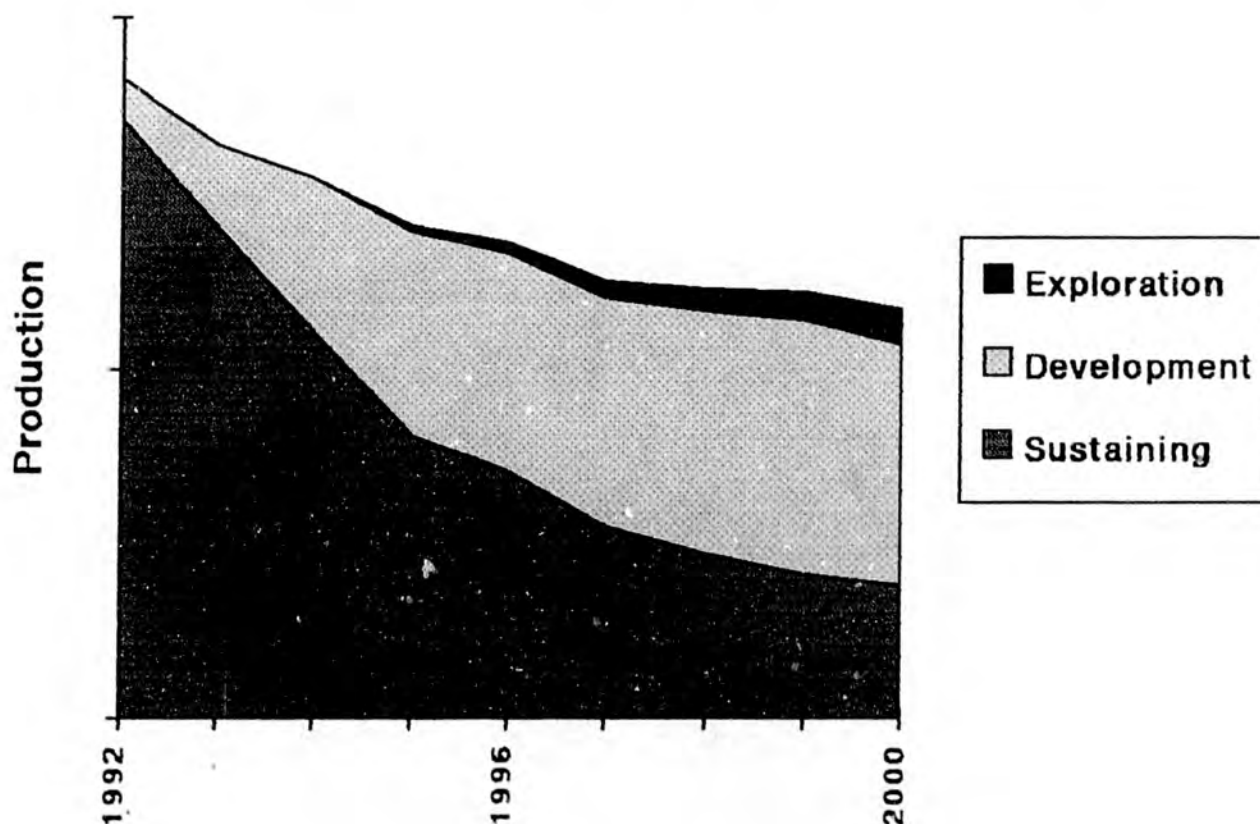


Figure 8. Production Potential from New Investments

The bottom area of the graph represents our production that would come from the existing investments in North Slope fields. We call it the "sustaining" production. It's basically what production would be if for some reason there were no further investments to develop the fields. As you can see, the production drops quite rapidly -- especially in the next few years -- and then it flattens out a bit toward the end of the 1990s although it is still always declining.

The significant layer of production lying immediately above the sustaining production is the additional production that we would get from continuing to make investments to develop the known fields on the Slope. These include drilling more wells at Prudhoe Bay, Lisburne, Endicott and Kuparuk; expanding the enhanced oil recovery, or EOR, operations at Prudhoe Bay and Kuparuk; extending the area of the Prudhoe Bay waterflood project; and developing Point McIntyre and Niakuk. As you can see, the production benefits of continuing these activities are substantial and will grow during the decade. The widening in this layer that you see starting in 1995 reflects the start up of the GHX2 gas handling project for Prudhoe Bay.

But the cost of these potential new investments is tremendous, and our share could total more than \$3 billion over the rest of this decade. This would be over and above the more than \$10 billion we will be paying in operating costs during the same time.

Finally, at the top of the graph you see a comparatively thin, but steadily widening layer of production beginning in the mid-1990s. This represents an estimate of the additional production we would hope to get from reservoirs yet to be discovered on the Slope. It represents the initial payoff for our exploration efforts. Comparing this layer to the other layers of production above the sustaining level, you can see once again why BP focuses its efforts so much on wringing every possible barrel out of the known **resources**, converting them into **reserves**.

But as you can also see, a substantial portion of the remaining **reserves** will only be produced as the result of substantial new investments. These new investments must stand or fall on their own economic merits. To make no bones about it, BP is a profit-seeking enterprise for our shareholders. We will make these new investments if they are sufficiently attractive.

Here is where Alaska can make a crucial contribution to help us justify making these new investments -- **it can maintain stability in its tax structure**. We did not like the change to the ELF formula in 1989. Not only was the change unnecessary, but the new formula was designed to penalize Prudhoe Bay and Kuparuk. And it does. Still, even under the new formula, we can evaluate the attractiveness of our new investment opportunities. But changing the rules of the game again, particularly if they target Prudhoe Bay and Kuparuk, will destabilize the tax structure and prejudice the major new investments and the resulting production that I have just discussed.

I'm not sure whether you have all had a chance to read the letter to the Finance Committee by David Pritchard of BP, raising a warning flag about the nickel-a-barrel oil tax surcharge. In case you haven't, I am attaching a copy of it to

my written statement to the Committee. I will not repeat his points now, but I urge you to consider his letter carefully.

Stability means more than not changing the tax laws. Since 1977 virtually every aspect of North Slope production and transportation operations which adversely impacted the state's revenue picture has been in litigation. Taxes, royalty and pipeline tariffs. While those of us based in Alaska understand that differences will exist between the State and the producers, this litigation always has high visibility in the board rooms of the producers. Alaska, when compared to other jurisdictions, is much more litigious -- a fact acknowledged two years ago by the Legislature's own international oil consultants. I am suggesting that at this stage of development on the North Slope we must find more rapid and economical ways to resolve our differences. Recently the State and the pipeline companies had a successful experience in alternate dispute resolution in the pipeline corrosion case, and we feel similar alternatives to litigation should be utilized for other disputes in the future.

Specifically with regard to tax administration, it is our experience that the rules of the game have been repeatedly changed as new "interpretations" are applied retroactively years after the fact. These new positions are very different from what was intended when the tax statutes and regulations were written. You would expect that it should at least be possible for us to pay the correct amount of royalties and taxes at the time they are due. But it turns out that some of these novel and unforeseeable interpretations make it impossible even theoretically for us to have paid the "correct" amount when we filed our returns.

Regardless of how or when the disputes over past taxes are resolved, the State needs to establish transparently clear rules about what we should be paying now for our current taxes. Tell us how to figure the right amount to pay, and we will pay it. But don't make us try to guess what someone years from now will think is the right amount. To give us stability, these rules need to be made in such a way that they will be applied consistently both today and in the future.

But I have not come here to complain about how the tax laws are being interpreted and applied, or to complain about seemingly endless litigation. So, let me return to the fundamental economic realities of the decline in North Slope oil production, which I was discussing. What I was saying earlier is that substantial, ongoing new investments in the fields can improve the revenue side of the economic picture by slowing down the rate of decline in production. Here is a graph depicting this.

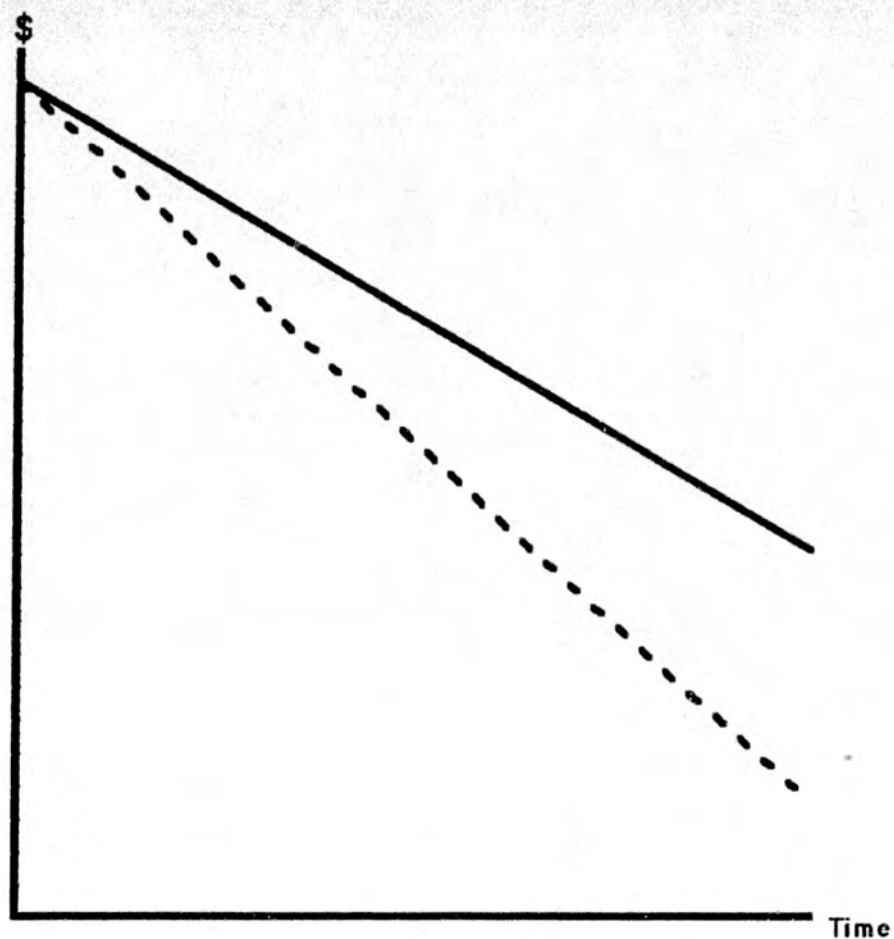


Figure 9. Slowing the Rate of Decline

What the new investments will do is shift the decline in the revenue side of the equation so that it falls off less steeply. But when you look at the cost side as well as the revenue side --

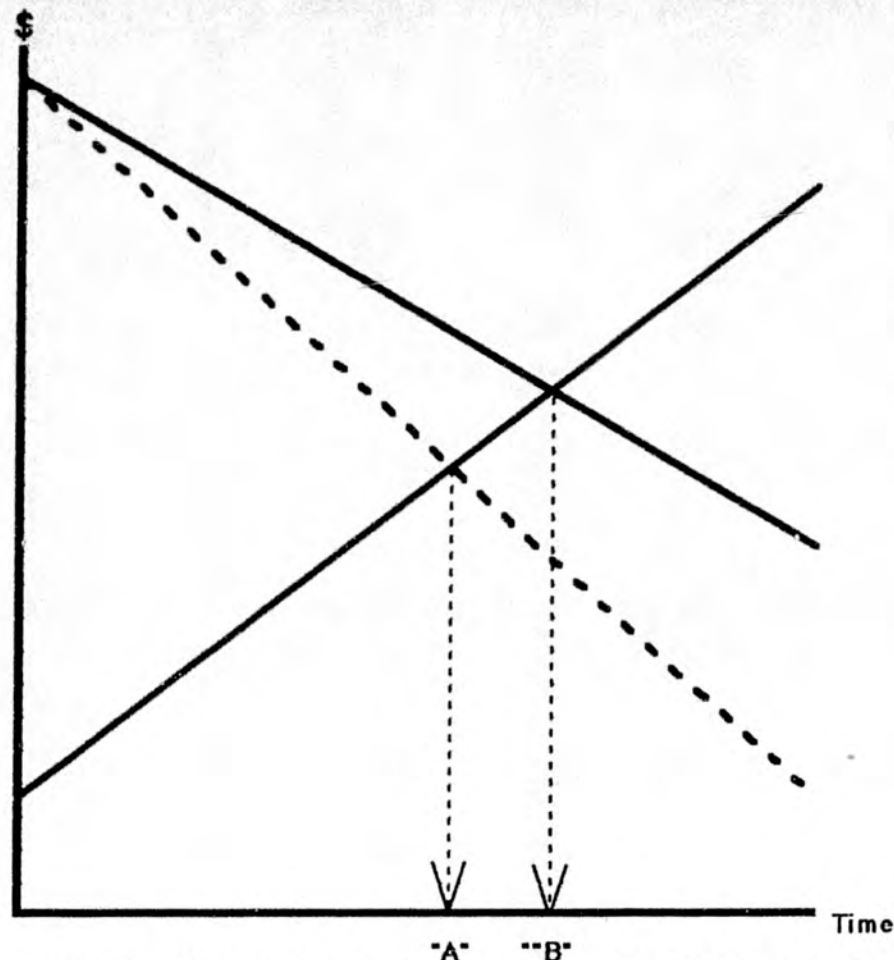


Figure 10. Effect of Slowing Decline for a Field with Rising Costs

you can see that new investments do not solve the problem. They only delay the "day of reckoning" from time "A" to time "B."

This means we have to work on the cost side of the equation as well. As I noted, the historic trend for operating costs has been a steady and continuous increase. Simply to arrest operating costs at their present level would be something of an achievement.

However, the only option that offers any chance of fully realizing the potential of the North Slope fields is to reverse the rising trend in costs and make them actually decline.

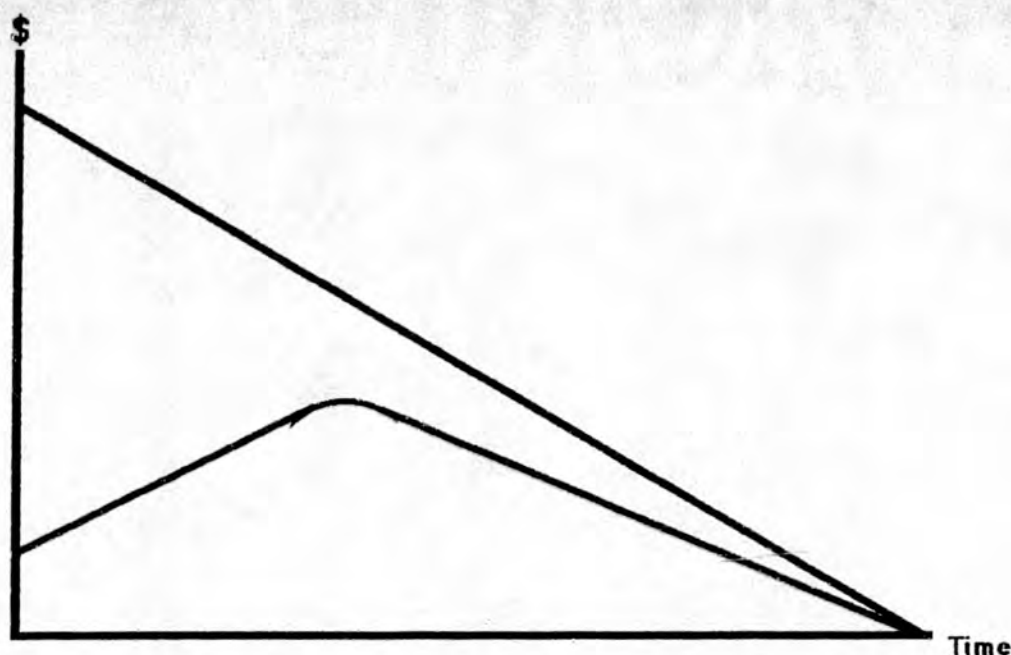


Figure 11. Saving a Declining Field by Reversing the Rising Cost Trend

This is the reality that the Prudhoe curve imposes on us. Declining production means that we have to get better control over our operating costs and reverse their historic tendency to rise. We at BP, like our counterparts at ARCO, have no choice but to operate in a new mode -- leaner, more efficient, smarter.

One of the first and most important initiatives to operate smarter on the Slope was the Shared Services Agreement between ARCO and BP for Prudhoe Bay operations. If both companies are performing some function on their respective sides of the field and there are economies of scale to be realized by combining those separate activities, the Shared Services Agreement calls for the two to be combined. It simply does not make sense to keep doing things separately when it would cost less to combine them. Our compelling economic situation overrides the sense of "turf" and rivalry that otherwise exists between two companies that are, after all, competitors. The Shared Services Agreement also calls on both companies to rethink their work practices and adopt the most efficient approach regardless of its source -- whether ARCO, BP, or anybody else.

BP is also changing the way it does business with its contractors. Some 80% of our operating costs are paid to outside contractors, so clearly any improvements we can achieve in efficiency with them can go a long way towards reversing the trend in operating costs. As Julian Darley told The Alliance in January:

"We're seeking partnerships with our suppliers that are truly collaborative -- ones driven by *value*, where *price* is only one of the components.

"A business partnership is a marriage. It has to be a win-win situation, or it won't work."

Too often and for too long, our contractors have not had a real understanding of BP's actual needs. This was mostly because we didn't tell them. We only said, "Here's what we want. How much will it cost?" Our new approach takes more effort on our part -- our people have to sit down with the bidders and explain not only **what** we want but **why** we want it. We at BP simply don't know our contractors' business as well as the contractors themselves know it, and so they must be able to tell us when they see something better than what we're asking for. This is what we mean by "collaborative partnering," and it's just another way for us to be smarter in the way we do business.

A third way for us to reduce our operating costs is to re-examine and challenge those things that we do in-house. Are these things really activities that BP is particularly good at doing? Are they things that BP should be doing itself? Are there external businesses that provide the same services and at less cost? We are finding that quite a lot of work we have been doing internally is really not part of what our business is all about. And so we are turning to outside sources for that work. This process has been given the inelegant name of "outsourcing." It is merely another way we have found to smarten up the way we do business.

Another way to do business smarter is to eliminate outright the lower-value activities performed by our staff. We must continually review what we are doing and question whether value is truly being added by these activities. We must search for ways to accomplish the same results with fewer people. Over the past few years we have moved many functions to Alaska that were previously performed Outside, and at the same time have steadily reduced the number of staff required overall. This has not been easy for us -- in fact the experience is quite painful, and we can sympathize with what the State must go through in cutting its spending back to a sustainable level. But we find there is little choice but to continue to reduce staff in this new era of declining production.

These initiatives -- the Shared Services Agreement with ARCO, partnering with our contractors, outsourcing, and staff reductions -- are manifestations of BP's commitment to remain in Alaska, for it is only by taking these and similar steps that we fully develop the resources that are here. Ironically, these very initiatives seem to be the source for the suspicion that we are about to leave. People have misunderstood the Shared Services Agreement as being a transfer of our operating functions over to ARCO, not as a way for both companies to save money. They see partnering as a way of cutting back on the scope of work we're doing, rather than as a way for both our partners and ourselves to benefit from working more closely together. They mistake outsourcing and staff reductions as signs that BP is withdrawing its business activity from the state. As I have explained, all these initiatives are our only way of coping with the economic reality being forced on us by the decline of North Slope production.

And here, too, there is an area where the State of Alaska can help us. As an unavoidable consequence of declining production, BP's focus, and that of our partners in the North Slope fields, must be to prioritize our expenditures, spending money on those projects that produce a return on our investment. It follows, then, that investments in projects that do not generate any return should only be made when there is a clear need for them.

At BP we pride ourselves for our efforts to be leaders among the industry in protecting health, safety and environmental quality. Our management are sincerely committed, at a personal level as well as corporately, to the pursuit of these goals. It is simply good business, as well as responsible corporate citizenship, for industry to make the investments necessary to protect and promote public health, safety and environmental quality. But, as Alyeska president James Hermiller told the Anchorage Chamber of Commerce last January:

"Regulatory controls should not be required merely because technology exists to do the job. Agencies must consider benefits versus costs."

And it is not good for the State to ignore the benefits versus costs, either. Again, as Mr. Hermiller pointed out:

"A good rule of thumb is that for every dollar Alyeska spends, the dollars received by the state for severance taxes and royalty payments are diminished by 25 cents, and the value of all production, including royalty oil, is reduced by one dollar."

The same is true whether the dollar is spent for TAPS, or for the marine terminal, the tankers or some other transportation facility. But, more fundamentally, the increased cost of doing business -- whether in the transportation sector or in the production operations -- becomes an economic drag that ultimately tends to reduce the rate of production and prevent the full recovery of the reserves. There will simply be less production on which royalty and production taxes are paid.

But please do not misunderstand me. We absolutely are not asking for a license to despoil the environment and imperil the health and safety of the public. By all means, protect the environment and people's well being. All we are suggesting is that, in this era of declining production, the State should work closer **with** us, instead of **against** us, to ensure that the justification is real, not illusory, before requiring us to make the investment. To the extent the State and industry share the same goals -- producing as much as possible while preserving and protecting health, safety and environmental quality -- the process of regulation should be more like a partnership than a confrontation.

I hope that by explaining what BP is doing and why we are doing it, I have dispelled the fears about our intentions. As I said at the beginning of these remarks, BP is committed to Alaska. We are not about to leave. We hope to be here for as long as the State will let us remain, so the tremendous petroleum resources here can be fully developed and produced.

Our actions are the best proof we can offer of our enduring commitment to Alaska. We are striving to convert still more of the petroleum **resource** into recoverable **reserves**, not only at Prudhoe Bay but for all the fields on the North Slope. We are relentlessly seeking for ways to do our business smarter. So far we have found Shared Services with ARCO, collaborative partnering with our outside vendors and contractors, outsourcing of functions that others do better than we, and achieving more ourselves with fewer people -- and we are still looking. We have

focused our exploration activities on those areas of Alaska that best fit our expertise, experience and business objectives. We seek a reinforcement of the partnership industry has with the State of Alaska and its people.

These are not the deeds of someone who is about to get out of Alaska. And as our slogan says, it is "deeds, not promises" that count.

Thank you for this opportunity to address the Committee.

SCOMM

79:3



Citizens' Oversight Council

on Oil and Other Hazardous Substances

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OIL SPILL RESPONSE ACTION CONTRACTORS

**A REPORT
To The
ALASKA STATE LEGISLATURE
SEVENTEENTH LEGISLATURE - SECOND SESSION
1992**

Prepared By

**The Citizens' Oversight Council
On Oil and Other Hazardous Substances
Pursuant to Section 11 of HB 196 (Ch. 92 SLA 1991)**

Council Members

**Harry R. Bader, Fairbanks • Leo J. Hannan, Anchorage • Kathryn L. Kinnear, Kodiak
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HB 196, SECTION 11, REPORT
OIL SPILL RESPONSE ACTION CONTRACTORS

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RECOMMENDATIONS

OBJECTIVE

The Citizens' Oversight Council, as required by the Legislature, has reviewed the entire subject of response action contractor civil liability and the status of oil spill contingency plan holders. The Council's objective in formulating recommendations is to assess the adequacy of the current laws limiting liability for oil spill response action contractors and to propose, where appropriate, alternatives that further the public's interest in a timely and reliable response to an oil spill.

EVALUATION CRITERIA

The Council first analyzed the liability laws and the realities of spill response in Alaska. Whenever the Council identified a risk that there might not be a timely and reliable response to an oil spill, the Council considered various options to ameliorate that risk. The Council was guided by the following criteria in making its final recommendations:

- * minimizing interference with private choices
- * providing incentives for maximum best effort in response
- * allowing for adaptability for regional and unique circumstances
- * achieving maximum shoreline protection
- * offering administrative efficiency
- * assuring clarity and consistency in standards
- * assuring reliability and responsibility in performance

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