

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2932 SCOMM 128: HOUSE SPEC. COMM. ON OIL AND GAS, 2001-02

TECHNOLOGY

drilling success and economics

Technology has greatly enhanced exploration and production opportunities. Anadarko, as one of the world's most active drillers, has been at the forefront of the industry's technological advances.

Technology has helped us increase the odds of finding oil and gas, improve the flow rates and ultimate recovery of reserves, and tap into oil and gas deposits that previously were out of reach, such as below salt or in the deep waters of the Gulf of Mexico.

Three-dimensional (3-D) seismic technology is among the most significant advancements. It provides a much clearer geologic snap-shot of what lies below and helps us better pinpoint the location of potential oil and gas-bearing formations.

Still, 3-D seismic and other advances in technology are no panacea. Technology cannot replace the *human* aspect, the ability to use the technology productively – to manipulate the data, interpret it, extrapolate and extract valuable information, and then calibrate the process with experience. Anadarko doesn't have exclusive rights to technology; what we *have* is the expertise to make the technology more *productive*. We have a technical staff that is second to none.

When others in the industry were drilling *around* salt deposits in the Gulf of Mexico because of the difficulty of "seeing" through them with seismic, we were mastering the technology to spot oil and gas pockets *underneath* the salt. We employed the same skills to find oil deposits beneath the desert sands in Algeria, where others had tried and failed.

Applying technology in innovative ways can yield significant improvements in the drilling and completion of oil and gas wells. The economics of tight-gas plays have improved dramatically in recent years, opening up whole new reservoirs to development. Anadarko's Bossier play ranks as a giant discovery with more than a trillion cubic feet of reserves, made possible by an aggressive performance-improvement program.



Similarly, explorers had been drilling through the Bossier tight-gas sands in east Texas for decades, usually treating them as a hazard on their way to deeper objectives. Our technical staff saw an opportunity to employ new completion techniques to release this tightly trapped gas in commercial quantities. Now, four years later, having discovered more than 1 Tcf of gas, we have 435 east Texas Bossier wells producing 285 MMcf/d; and we're far from finished. In fact, we have carried the same techniques over to the Vernon field, a similar play in northern Louisiana that we believe is just as big as our east Texas Bossier play.

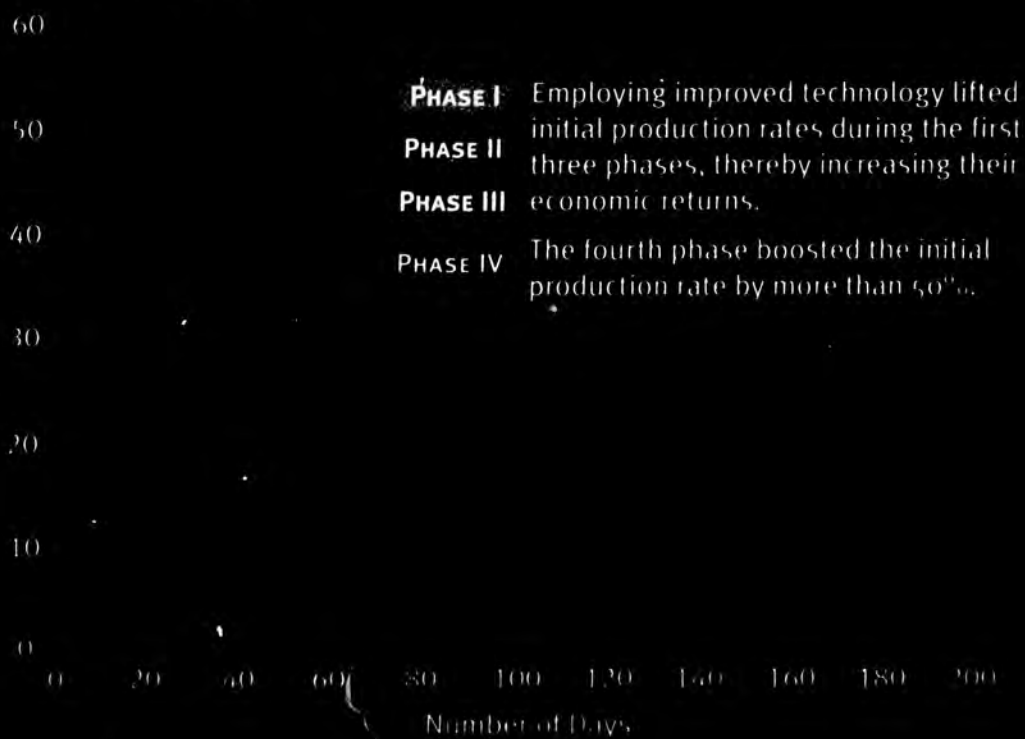
The Bossier play provides additional evidence of how our staff is every bit as important as the technology itself. With the opportunity to drill hundreds of wells in one concentrated area, we embarked on a project to incrementally improve every aspect of the drilling and completion process... a *manufacturing* process that we fine-tune every day.

The graph on the facing page shows the production performance of Bossier well completions over four different time periods. Each of the first three completion phases resulted in improved initial production rates. This effort took a quantum leap in the fourth phase, when we not only boosted the initial production rate by more than 50% but also significantly raised the stabilized production rate, which translates to increased proved reserves and higher value. In the process of achieving these results, we improved profitability by cutting the time it takes to get gas to market by 50%. *That* is what we mean by "productive use of technology."

Anadarko doesn't have exclusive rights to technology. What we have is the expertise to make the technology more productive. We have a technical staff that is second to none.



Bossier Production Performance
(Mcf/d per Foot of Net Pay)



DRILLING

a balanced prospect portfolio

Anadarko's large portfolio of projects represents the heart and soul of our organic growth strategy. Through both up-cycles and down, we strive to carefully balance our exploration and development drilling programs, shifting the focus and size of the capital budget as needed to stay ahead of the market cycle.

The portfolio is divided into three stages, representing the normal path of a drilling project. First, we evaluate new opportunities based on our technical assessment of where hydrocarbons "should" be. In the second stage, select projects are further investigated with seismic and other tools and, ultimately, tested by the drillbit. If the wildcat well is unsuccessful, the project is post-appraised and either discarded or returned to stage one for further study, aided by valuable data gained in the drilling process. If successful, however, it moves to the third stage where "conceptual" ideas become real, moneymaking oil and gas fields.

Anadarko's Algeria oil project is a perfect example of this lifecycle. Back in 1986, the Algerian government invited explorers to drill for oil in the Sahara Desert. We evaluated the opportunity and concluded that huge potential existed. Our first wildcat well in 1991, however, was a dry hole. Rather than quit, we went back to the drawing board. Using new seismic data in combination with information gained through our first well, we determined that our theory was sound; we just drilled the well in the wrong spot. Now, 11 years later, we have successfully drilled 14 out of 20 exploratory prospects, finding a total of 2.8 billion barrels of oil. In January 2002, we achieved gross production of more than 200,000 barrels per day. Our goal is 500,000 barrels per day in 2003 from the fields we've already discovered, with more expected by 2006.

Anadarko's project portfolio helps describe the company's basic business plan, capital allocation policy and risk management strategies. Operationally, the portfolio reflects our drillbit focus. Financially, it embodies investment flexibility to match market cycles. And on balance, it lowers our overall risk profile.



In 2001, we signed agreements allowing us to resume and expand our Algerian exploration program, bringing the project full-cycle in our portfolio.

Ideally, each exploration success sets up several development locations that can be added to the portfolio and drilled at the appropriate point in the industry cycle. And, in some cases such as the Bossier natural gas play in east Texas and Vernon field in Louisiana, the same successful drilling and completion techniques can be applied across hundreds of miles of lease acreage. We call this "running room."

While Anadarko's primary focus is on organic growth, we also have grown our portfolio successfully through acquisitions. We don't buy properties solely for their existing production and proved reserves. We also seek upside that can be captured through the drillbit, applying techniques that have been successful elsewhere to add new prospects to the portfolio.

This portfolio has helped Anadarko become an industry leader in adding reserves through the drillbit. In 2001, we drilled 114 exploratory wells (84 net) with a 71% success rate. We drilled 1,295 development wells (965 net) with a 98% success rate. And, we found more than 400 million BOE of proved reserves. In total, we replaced 221% of the reserves produced, with a 173% replacement rate excluding acquisitions and divestitures. This marks our 20th consecutive year to more than replace annual production with new reserves, a record unmatched in the energy industry.

Ideally, each exploration success sets up several development locations that can be added to the portfolio and drilled at the appropriate point in the industry cycle.

PORTFOLIO BALANCE

3 stages

Long Term

North Slope
Foothills

New Contract

Mackenzie Delta
Nova Scotia Shelf

Near Term

Bossier Wildcats
Vernon Wildcats
Cotton Valley Wildcats
Georgetown / Glen Rose

Shallow Water Exploration
Sub-salt (prospect inventory)
Deepwater (prospect inventory)

Coalbed Methane
Deep Basin Gas
Overthrust Plays

Northeast British Columbia
Alberta Foothills
Northwest Territories

Tunisia
Australia
West Africa (Congo, Gabon)

Immediate Impact

Bossier / Vernon
Carthage
Austin Chalk / Buda
Kent Bayou

Shallow Water Exploitation
Sub-salt (Tarantula, Pardner)

Alpine

Green River Basin
Wamsutter Area

Hugoton
Golden Trend
Enhanced Recovery
Ozona

Dawson
Wild Hay
SE / SW Saskatchewan
Heavy Oil

Algeria
Venezuela
Oman
Qatar

GLOBAL OPPORTUNITY

an exciting industry environment

Anadarko's financial and operating strategies are based on our view of world oil and gas markets; where prices are within the cycle, where they are headed and what forces are driving them. We conduct extensive macroeconomic analyses of these markets to identify opportunities and allocate capital. Entering 2002, we see a world *full* of opportunities.

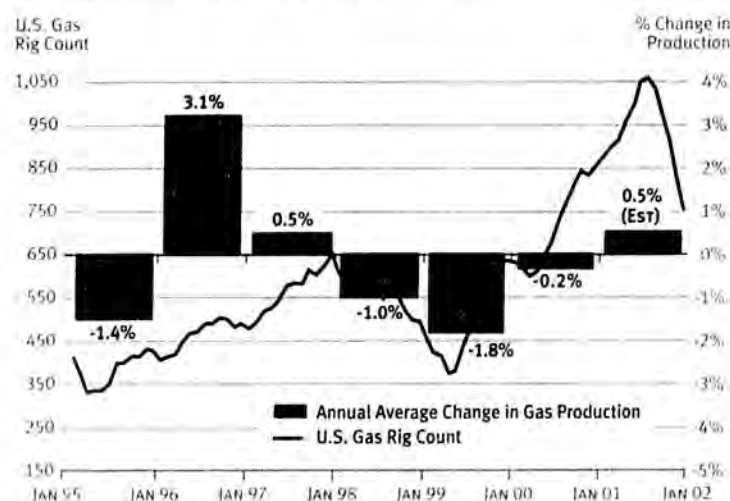
Despite continuous headlines about political, social and economic turmoil in the Middle East and other major oil-producing regions, crude oil prices remain within their historical trading range of about \$18 to \$24 per barrel, with occasional, short-lived excursions above and below this range. We believe oil markets function efficiently and that, over the long term, prices will remain within this range.

For more than a decade, natural gas has been gaining market share as America's "fuel of the future," a domestically abundant, cleaner-burning energy source. In recent years, gas has captured the vast majority of new and proposed power generation capacity, beating traditional competitors – coal, fuel oil, nuclear and hydro. With this market as the driving force, government and industry forecasters have projected U.S. gas consumption reaching 32 Tcf by 2020, up 42% from the 22.5 Tcf consumed in 2000.

Our experience during the past two years, however, has led us to conclude that supplying a 32 Tcf U.S. gas market will require much higher prices. Drilling for natural gas ramped up 70% to more than 1,000 rigs in mid 2001 in response to rapidly rising prices, yet the industry was unable to grow U.S. production to match the 2% historical rate of demand growth. In fact, the 30% drop-off in drilling from mid 2001 to about 700 gas rigs at year end likely wiped out the gains made during the drilling spree. We estimate 2001 U.S. gas production was about flat with production in 2000, despite a *significantly* higher average rig count.

The factors driving these results are numerous. One of the first to appear during the up cycle was inflation of drilling and other service costs, which increased to levels that were unsupportable when gas prices fell back below \$3 per Mcf.

Gas Rig Counts & Change in Gas Production



SOURCE: BAKER HUGHES / IHS ENERGY / ANADARKO ESTIMATE

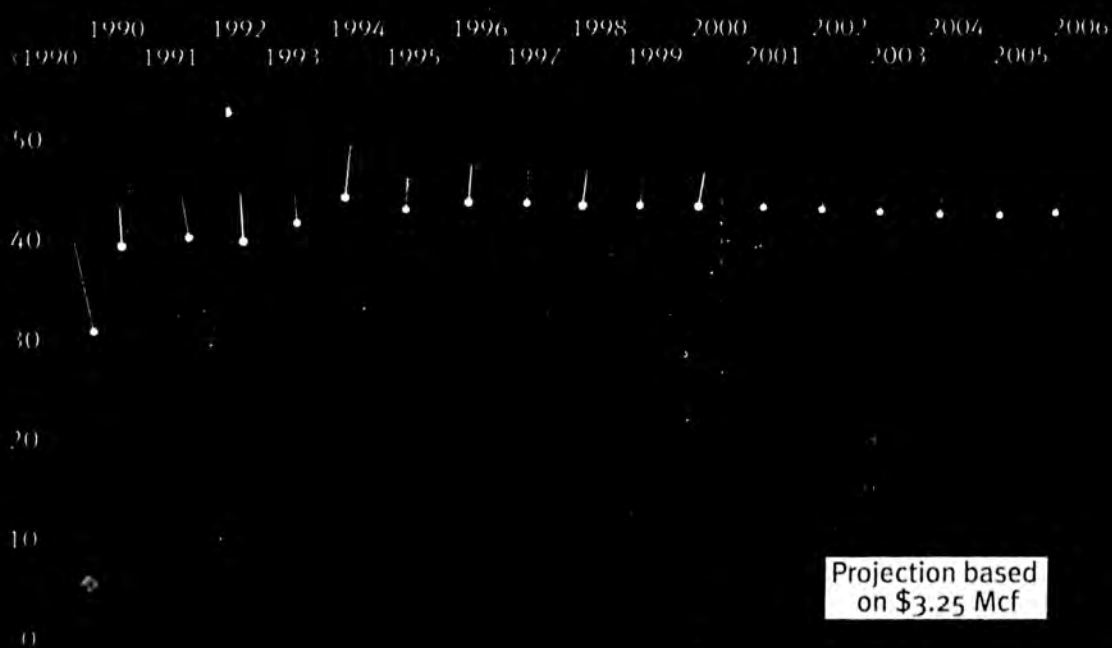
A second major factor is a lack of access to high-potential prospects. The industry has drilled most of the big, low-cost fields accessible in the lower 48 states. Most new production is higher cost. It's deeper and more expensive to drill, complete and produce. Vast high-potential, conventional fields do remain, but largely have been kept off-limits for exploration.

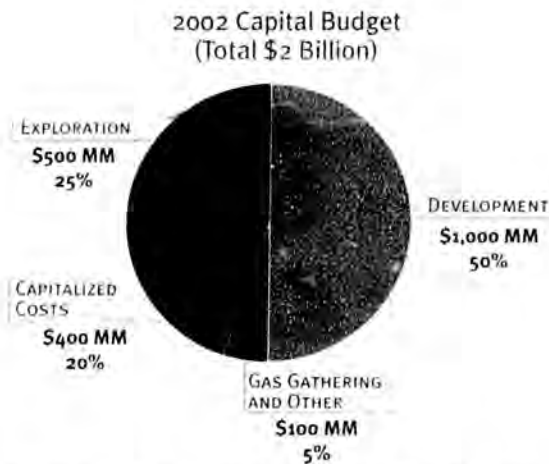
A third major factor is an overall U.S. gas production decline rate of nearly 25%, with the average *new* gas well declining more than 50% within its first year. In 2002, the U.S. will have to add 12 Bcf/d of gas supply, equal to three quarters of western Canada's gas production, just to stay *flat*!

We believe higher gas prices are coming and will be here to stay, although significant volatility will continue to exist. In this environment, Anadarko is positioned to thrive. We have a large portfolio of drilling prospects in the few remaining under-explored areas of North America. Our holdings span more than 8 million acres in the Rocky Mountains alone, as well as an extensive deepwater Gulf of Mexico position and nearly 5 million acres in Canada. We also remain active overseas, balancing our gas-oriented North American portfolio with primarily oil-focused projects in Algeria, Qatar, Australia and elsewhere.

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U.S. Gas Production by Year of Initial Production*
(Billions)





The 2002 capital budget includes a healthy level of investment for exploration projects, which will help ensure Anadarko can deliver double-digit production growth in the next industry upturn.

While we've not always had the financial strength and flexibility we have today, Anadarko *has* always been able to continue exploring during the downturns. This is why we've been so successful. We "reload" our drilling inventory for the next upturn. And, we keep our industry-leading staff challenged and contributing to shareholder value, through both up cycles and down.

In 2002, we plan to actively explore in all of North America's high-potential areas, including the deepwater and subsalt plays in the Gulf of Mexico, the deep basin and overthrust plays in the Rocky Mountains, a variety of plays in western Canada, and in both the North Slope and Foothills regions of Alaska. We will continue exploring the tight-gas plays of east Texas and Louisiana. We also will drill some important exploratory wells this year in West Africa and Australia's Northwest Shelf and re-launch our exploration program in Algeria.

On the development side, while the level of activity is substantially slowed, we will continue working in all of our core areas to *some* extent, depending in part on rig rates and service costs in each area.

We're coming off a very volatile yet very successful year.

"We will maintain a flexible capital program, diligently watching the market and capturing opportunities to enhance shareholder value... whether that's through the drillbit, through acquisitions or through share repurchases."

The industry is in a down cycle as we enter 2002, but we *know* the turnaround is coming. Anadarko is prepared – operationally and financially – to manage profitably through the volatility. Just as we did in 2001, we will maintain a flexible capital program, diligently watching the market and capturing opportunities to enhance shareholder value... whether that's through the drillbit, through acquisitions or through share repurchases. The market is full of great opportunities, and we will execute our plan to capture them.

Sincerely,

Robert J. Allison, Jr.
Chairman of the Board

John N. Seitz
President and Chief Executive Officer

February 14, 2002

ON A PERSONAL NOTE: *At the end of 2001, Vice Chairman George Lindahl retired from Anadarko. He joined us at the time of the UPR merger and made invaluable contributions toward building the "new" Anadarko. He still serves on our board.*

Lawrence M. Jones retired from Anadarko's board after many years' service on the UPR board. He actually served on Anadarko's first board of directors in 1986. We appreciate his wise counsel and advice and wish the best for Larry and his family in the future.

In January 2002, I was pleased and proud to pass the CEO title to John Seitz, who has worked closely with me at Anadarko for 25 years. John is an expert geologist and an outstanding leader. I know he will do well in his expanded role. I am not retiring and intend to remain a very active Chairman.

PERFORMANCE

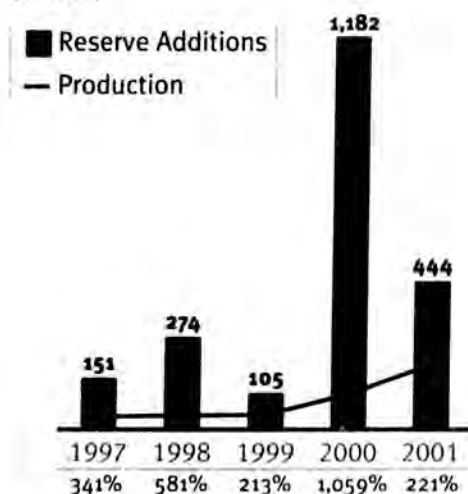
"Making money in our business depends on two things. The first is finding oil and gas at low costs. The second is producing oil and gas at the right times."

to-capitalization in the middle of a down cycle, we have the *capacity* to fund investments that make economic sense; but we will *not* over-leverage in the process.

WE WILL FOCUS ON ADDING RESERVES, NOT PRODUCTION.

Anadarko is *still* a double-digit-growth company. As promised, we grew both reserves and production at double-digit rates in 2001. We have the locations in inventory to achieve such results again. But, drilling these locations and putting the wells on production in today's low-price environment reduces potential value, since first-year production decline rates often exceed 50%. Instead, we will manage the drilling portfolio for the next "up" cycle, adding value in reserves and drilling locations. This will enhance our ability to deliver double-digit production growth after the upturn. Any significant production growth in 2002 is more likely to be on a *per share basis* — from a combination of exploration success, property acquisitions and share repurchases. Looking at proved reserves, we expect to continue our 20-year history of more than replacing annual production. Our 2002 capital budget includes drilling projects that have net (unrisked) reserve potential of more than 2 billion BOE of new reserves.

Reserve Replacement
(MMBOE)



Anadarko has more than replaced its annual production volumes with new reserves for 20 consecutive years, with reserve replacement rates exceeding 200% in each of the past five years.

WE WILL WORK TO HIGH-GRADE THE PORTFOLIO.

We will consider buying producing properties, particularly in cases where those assets can contribute to future organic growth. We also will look to sell non-core properties, effectively trading these for others purchased in our core areas, thereby focusing our people and financial resources where we can create the most value.

In addition to these key operating and financial strategies, we will efficiently and prudently manage costs, getting more out of each dollar and making sure money is spent where it will do the most good.

The common theme throughout our 2002 action plan is "flexibility." Whether we focus on reserves versus production, drilling versus acquisitions and/or buybacks, investing cash flow versus debt or equity financing, our action plan lets us make mid-course corrections to match market conditions. If energy prices increase sufficiently later this year, thereby boosting our available cash flow, we will accelerate development drilling.

Making money in our business depends on two things. The first is finding oil and gas at low costs. The second is producing oil and gas *at the right times*. It's important to avoid the *wrong* moves at the *wrong* times in the cycles. Anadarko has a track record of recognizing the market turning points. We saw this current down cycle early and started the shift at the end of the second quarter of 2001. We will be watching carefully for signs of the next up cycle.

This philosophy is reflected in our \$2 billion capital budget for 2002, which is tied to expected cash flow for the year. About 25% goes to exploration, while 50% is earmarked for development, including \$400 million of facilities construction. This is about the same percentage breakdown we achieved in 2001, keeping in mind that we shifted heavily toward exploration in the second half of last year. Also, a full 70% of the 2002 exploration spending will go to drilling, compared with only 59% in 2001.

TO OUR SHAREHOLDERS

a strategic overview

2001 was a roller coaster ride! Energy prices started the year at unsustainably high levels and ended the year at unsustainably low levels. This has always been a cyclical business, but the recent volatility has been unusually challenging. Yet within this tough environment, Anadarko had a great year, adding tremendous value:



BOB ALLISON AND JOHN SEITZ

- We had record cash flow from operations.
- We had record earnings, excluding non-cash impairments of oil and gas properties.
- Oil and gas sales volumes rose 78% overall, or 30% on a per share basis.
- We increased reserves 12% with a 221% reserve replacement rate, including more than 170% with the drillbit.
- We added significant reserves and production organically with discoveries across our base of operations.
- We completed two acquisitions – Berkley Petroleum and Gulfstream Resources – that provide substantial drillbit upside in addition to reserves and production.
- Even with investments totaling \$4.6 billion in 2001, we maintained a strong balance sheet, ending the year with a 44% debt-to-capitalization ratio.

No doubt about it – 2001 was a banner year.

Our analysis indicates 2002 could be a mirror image of 2001, with natural gas prices starting the year at depressed levels and escalating somewhere around mid year as supply and demand come back into balance. Our positive outlook for gas is based on two key premises.

First, we *know* natural gas supply is falling. The industry demonstrated last year that full-out drilling efforts result in U.S. gas production increases of less than 2%. On the other hand, we estimate that if gas prices hold in the \$2 to \$2.50 range throughout 2002, reduced drilling will lead to a 2% to 3% decline in U.S. gas production. Imports could partially offset the decline, but not by much at these prices.

Second, we *know* demand will return. Low gas prices, combined with a turnaround in the U.S. economy and a return to normal weather patterns, will restore gas demand to its historical growth trajectory. What we don't know is *when* this will occur. Cold weather in February and March, a hot summer and increased industrial activity would balance gas supply and demand sooner rather than later.

In the meantime, we have implemented an action plan that works even if the turnaround doesn't come this year. We believe these are the right strategies to build value for shareholders.

WE WILL CONTINUE TO EXERCISE CAPITAL DISCIPLINE.

We work to ensure that *whatever* we invest in creates value, whether that's drilling for oil and gas, acquiring producing properties or repurchasing Anadarko common stock. And in making these investments, we will continue to prudently manage the balance sheet. At about 44% debt-

FIVE YEARS AT A GLANCE*

<i>dollars in millions, except per share amounts</i>		% change				
	2001	2001-2000	2000	1999	1998	1997
Revenues	\$ 8,369	52	\$ 5,500	\$ 1,706	\$ 1,307	\$ 1,570
Net Income (Loss)	(188)	nm	796	32	(49)	107
Net Income (Loss) Excluding Impairments	1,389	68	828	47	(5)	107
Cash Flow from Operations before Changes in Assets and Liabilities	\$ 3,429	83	\$ 1,875	\$ 313	\$ 211	\$ 357
Per Common Share:						
Net Income (Loss) - Diluted	\$ (0.75)	nm	\$ 4.16	\$ 0.25	\$ (0.41)	\$ 0.89
Net Income (Loss) Excluding Impairments - Diluted	\$ 5.25	22	\$ 4.32	\$ 0.37	\$ (0.04)	\$ 0.89
Cash Flow - Basic	\$ 13.71	35	\$ 10.19	\$ 2.50	\$ 1.76	\$ 2.99
Dividends	\$ 0.225	13	\$ 0.20	\$ 0.20	\$ 0.1875	\$ 0.15
Average Shares Outstanding	250	36	184	125	120	119
Capital Expenditures	\$ 3,316	94	\$ 1,708	\$ 680	\$ 917	\$ 686
Total Debt	\$ 5,050	27	\$ 3,984	\$ 1,443	\$ 1,425	\$ 956
Stockholders' Equity	6,385	(6)	6,786	1,535	1,259	1,117
Total Assets	\$ 16,771	1	\$ 16,590	\$ 4,098	\$ 3,633	\$ 2,992
Annual Sales Volumes:						
Gas (Bcf)	695	81	385	170	177	179
Oil and Condensate (MMBbl)	68	89	36	15	11	9
NGLs (MMBbl)	15	25	12	7	7	5
Total Barrels of Oil Equivalent (MMBOE)	199	78	112	50	47	44
Average Daily Sales Volumes:						
Gas (MMcf/d)	1,904	81	1,052	465	484	490
Oil and Condensate (MBbl/d)	186	90	98	40	30	25
NGLs (MBbl/d)	42	27	33	18	18	15
Total Barrels of Oil Equivalent (MBOE/d)	546	78	306	135	129	121
Oil Reserves (MMBbl)	1,132	8	1,046	573	494	420
Gas Reserves (Tcf)	7.0	15	6.1	2.5	2.6	1.7
Total Reserves (MMBOE)	2,305	12	2,061	991	935	708
Worldwide Finding Cost (\$/BOE)**	\$ 8.53	19	\$ 7.19	\$ 4.87	\$ 3.13	\$ 4.28
Worldwide Reserve Replacement (% of Production)	221%	(79)	1,059%	213%	581%	341%
Number of Employees	3,500	0	3,500	1,400	1,500	1,400

* Consolidated for Anadarko Petroleum Corporation and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.

** Worldwide finding costs are calculated by dividing worldwide costs incurred by the worldwide reserve additions, excluding sales in place.

TABLE OF MEASURES

Bcf	Billion cubic feet	MMBOE	Million BOE
BOE	Barrels of oil equivalent	MMcf	Million cubic feet
MBbl	Thousand barrels	NGLs	Natural gas liquids
MBOE	Thousand BOE	Tcf	Trillion cubic feet
Mcf	Thousand cubic feet	/d	Per day
MMBbl	Million barrels		

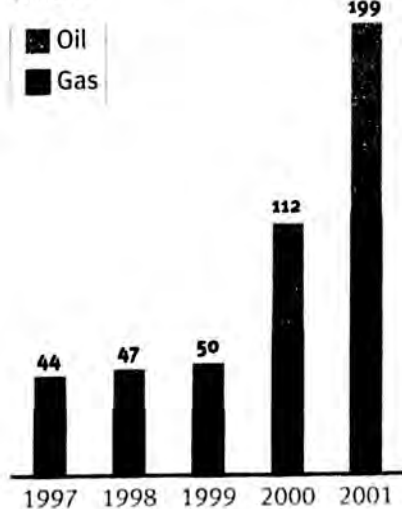
This is a Summary Annual Report.
 Anadarko's audited financial statements with accompanying footnotes and Management's Discussion and Analysis will be published in Anadarko's Annual Report on Form 10-K, which will be available in mid March.

ANADARKO

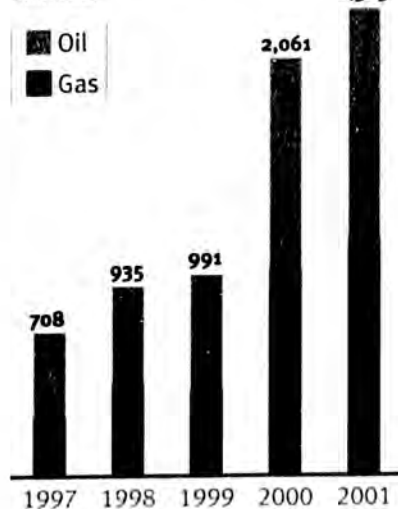
corporate profile



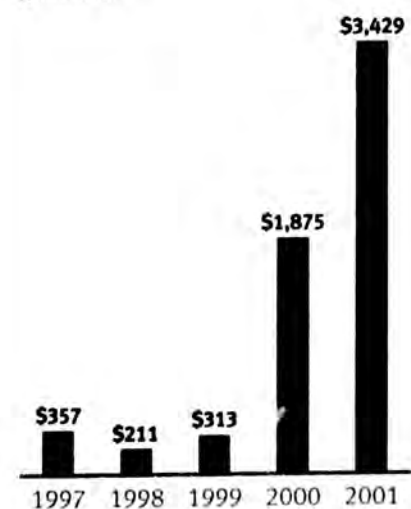
Annual Sales Volumes
(MMBOE)



Proved Reserves
(MMBOE)



Cash Flow
(\$ Millions)



SCOMM

128:17



Andex close to Nenana deal, gas could go to Anchorage

By Kay Cashman

PNA Publisher

Jim Dodson, executive vice president of Andex Resources LLC of Houston, told PNA that his firm is "very close to a deal with Doyon" to explore and develop the oil and gas resources of approximately 38,000 acres in the Nenana sedimentary basin in Interior Alaska.

The privately owned independent is also working with the state for an exploration license in the basin. Dodson said Doyon Ltd. was instrumental in getting Andex interested in what geologists view as a gas-prone area.

"The Andex license application is for several hundred thousand acres in the basin. Our land is in a fairly strategic location in the deepest part of the basin. We're an island within state land," Doyon Vice President of Lands and Natural Resources Jim Mery told PNA.

"Doyon has been a tremendous source of information for us. We couldn't have put together the picture we have — the picture that made us go after this deal — without Doyon," he said.

Two right-of-ways to Anchorage

The Nenana basin, which Doyon Ltd. documents said could hold reserves "on the order of 250 million barrels of recoverable oil and 250 Bcf to 1 Tcf of recoverable gas," was explored by ARCO Alaska in the early 1980s. ARCO drilled a well in the basin in 1984 but dropped its plans for further exploration when oil prices collapsed, Mery said.

It has enough gas, Dodson believes, to meet market demands for Fairbanks and possibly Anchorage: "We see a home heating market in Fairbanks and an electric generation market. We also see a market for supplanting diesel and other fuels to Interior mines. It's a 30 million to 50 million cubic feet a day market (for natural gas) in the Interior. ...

"If we found a significant gas discovery up there we could seriously look at supplying Anchorage," Dodson added.

"By Alaska standards the Nenana basin is not that far from Anchorage. ... We're south of the Brooks Range and there are two rights of way that could be used for a pipeline between the basin and Anchorage

— the highway and the railroad.”

Seismic winter of 2002-2003

Andex's work commitment is confidential, Dodson said. “There won't be any seismic or geophysical work this winter. We expect to shoot our first seismic in the winter of 2002-2003.”

Andex is a good choice for development in the basin, Mery said. Mark Myers, director of the state Division of Oil and Gas, agreed with him.

Both men pointed to the fact that the company is well-funded, involved with other projects in Alaska and looking to get even more involved in the state. (See articles in this issue about Netricity and the Slugger unit.)

“We have been working with them for over a year and gotten to know them very well. A lot of them are old Shell Oil people. ... Andex's president, Ernie LaFleur, was head of Alaska exploration for Shell. I am very impressed with their geology staff,” Mery said.

Native issues

Andex appears sensitive to the Native issues that surround any development in the Nenana basin, Mery said.

“While we at Doyon are supportive of oil and gas in this area, we are still very committed to making sure that the state in its best interest finding process for Andex's exploration license has all the information in front of it to make sure that the appropriate mitigation measures can be taken to avoid negative impacts on the area. ...

Mery said there are a “number of youth cultural camps and other educational activities centered out of old Minto village on the Tanana River, as well as important hunting, trapping and fishing that takes place on numerous lakes in the Minto Flats, all of which would be in the general area of the possible exploration and would have to be taken into consideration.

Alaska office a possibility

The focus of Andex's exploration will be gas, Dodson said.

“When industry explored the basin in the early '80s, their focus was oil but they knew it was a gas-prone basin and thought there was also a good shot at oil. Andex's focus is gas. We'd be happy if we found oil, but our focus is traditional natural gas,” he said.

An Alaska office is something “we may have one of these days, depending how big our business in Alaska gets,” Dodson said.

Company Profile

- ***Founded in Late 1998***
- ***\$70 million in venture capital, and \$20 million in land assets***
- ***Principles:***
 - 55% George Soros (Soros Fund Management)
Venture Capital Fund
 - 35% Wolf Family (Erving Wolf - Andex Chairman)

Founded Inexco Oil in 1960's creating market cap of nearly
\$1 billion before sale to LL&E in 1986
 - 10% Andex Management and Employees
- ***Operations began in early 1999***
- ***First well commenced July 1999***
- ***First production 4th Quarter 1999***

Andex Business Model

- ***Andex is a significant source of venture capital to fund the E&P Industry for natural gas exploration and development projects***
 - Highly diversified portfolio both geologically and geographically.
 - Large deal flow; 600-700 proposals per year.
 - Very selective screening process; invest in 10% of deals reviewed.
- ***Experienced Management Team***
 - 12 senior level professionals from major oil and gas companies, primarily Shell Oil
 - Backed by Erving Wolf and Soros Fund Management.
- ***Investment Objective***
 - Range of \$0.5 million to \$1.5 million of risk capital per venture.
 - Working Interest Range 10-50% (avg. 25%)
 - 60+ ventures / year
 - ROI > 25%



12/14/01

Management Team:

Erving Wolf – Chairman, 1951 formed Wolf Exploration Co., 1962 formed Andover Oil Co. (1982 sold to form Santa Fe Intl.), 1968 formed Inexco Oil Co. \$1 Billion market cap on NYSE (1986 merged with Louisiana Land & Expl.), Discovered the 5TCF Madden Field in Wyoming, and N. Americas largest uranium deposit.

W. Neil McBean – CEO, 30 years of experience in the oil and gas industry with some 16 years as President, and then CEO of PetroCorp, a publicly traded energy independent. Prior to that time, he spent 13 years with Tenneco Oil Company, where he served in a range of production management and technical capacities.

Ernest LaFlure – President, 20 years at Shell Oil Co., 1 yr. President Benz Energy, Extensive E&P management assignments throughout the continental U.S., Alaska and offshore Gulf of Mexico. Led business units focused on exploration, field exploitation and acquisitions.

Steve Slack – VP Finance and CFO, 25 years experience in finance and international business, founder and co-owner of IMDST, CFO & Director Pogo Producing, Regional V.P. Energy Division at Chemical Bank, and V.P. Energy Division at Bank of America.

Jim Dodson – Executive V.P., 15 years experience in the oil and gas E&P business, worked as an exploration geologist at Pinnacle Energy, entered private legal practice with Poulson, Odell & Peterson, became corporate legal counsel at Marathon Oil Co., and worked at MCN Energy before assuming his current position focusing on Rocky Mtn. E&P in Andex's Denver office.

Tom Dodds- V.P. Land and Operations, has 27 years experience in land management, he has worked at Killam & Hurd, Inexco Oil Co., LL&E, and Wolf Companies before joining Andex.

Bill Schroeter – V.P. Exploration, has over 19 years experience in upstream oil and gas for both Amerada Hess and Texaco, he has extensive continental U.S. exploration experience and has extensive experience in asset divestitures and acquisitions.

Management Team (cont.):

Jim Honert – New Ventures Manager, 26 years of industry experience, 16 years with Shell in a variety of offshore and onshore plays, a specialist in stratigraphy, subsurface geology and geophysical interpretation.

Bob Mason – Rocky Mountain Exploration Manager, a geologist with 29 years experience, started at Shell in 1972, joined Southland Royalty in 1979, became Region Geologist for Burlington Resources upon acquisition of Southland Royalty, promoted to Senior Geologic Advisor for Burlington's Rocky Mountain Region and worked for Tom Brown Inc. for 2 years before joining Andex.

Frank Falbo – Manager of Sales & Acquisitions, a reservoir engineer with over 16 years experience, primarily at Shell. Frank has been involved in maximizing the performance of producing assets in the GOM, Rocky Mountain and Western United States and has provided engineering support for exploration and New Venture efforts. He has participated in numerous sales and acquisitions. Prior to joining Andex Frank practiced oil & gas law with the firm of Kilburn, Jones, Gill & Campbell.

David Witter – Manager of Geology, an explorationist with over 17 years of experience in the oil & gas industry in a variety of geologic provinces. Mr. Witter has worked for primarily Shell, and Transco Energy. In addition to play and prospect generation, Mr. Witter has extensive experience in managing multidisciplinary teams, deal screening, and prospect sales.

John Lambuth – Chief Geophysicist, Mr. Lambuth has over 15 years of experience in the oil and gas industry. He began his career with Shell working a variety of assignments involving the acquisition, processing, and interpretation of seismic data, and managed a seismic crew responsible for acquiring most of shell's proprietary 3D datasets. Mr. Lambuth also held positions with Meridian Resource Corp., Benz Energy and El Paso Production. Mr. Lambuth has experience in all disciplines of geophysics including some of the newer AVO and Pre-Stack Depth technologies.

SCOMM

128:18

**Presentation on the TAGS
Small Project
February 2002**

**Yukon Pacific Corporation
A Business Unit of CSX Corporation**

Cover Letter for YPC presentation on the TAGS Small Project configuration

Introduction

Yukon Pacific Corporation is evaluating a configuration of the Trans-Alaska Gas System that is smaller than YPC's current design basis and incorporates the sale of ethane and propane as separate products. YPC has prepared a powerpoint presentation regarding the TAGS Small Project. This letter is intended to accompany the presentation and provide supplement information.

The TAGS Small Project consists of a 7 million metric ton per year (MTA) LNG project with the addition of ethane extraction for an in-state petrochemical industry and propane extraction for sale as liquefied petroleum gas (LPG) to Asia. The initial in-house economic runs for this configuration are producing encouraging results.

Project size and ramp-up

The TAGS Small Project, as currently envisioned, requires a flow rate of 1.4 bscfd.

A premise of YPC's Small Project is that capacity ramp-up can be avoided by serving five relatively small markets simultaneously. These five markets are: 2 MTA of LNG to North America; 5 MTA of LNG to Asia; 60,000 barrels per day of ethane for feed to an in-state petrochemical industry; 75,000 barrels per day of propane as LPG to Asia and 50 mmscfd of utility grade gas for in-state use.

Considering the volumes for the Canadian pipeline proposals, there should be little issue with the assumption that 2 MTA (280 mmscfd) of gas can be placed in the North American market if competitively priced. The 5 MTA of LNG to Asia is about two thirds the size of the 7-8 MTA "market entry project" discussed by the Alaska North Slope LNG Project during testimony before the Alaska Legislature in 2001. The quantity of ethane is approximately the same as feedstock rates to petrochemical projects being proposed for Fairbanks and Alberta. The Asian LPG market appears to be strengthening as evidenced by the upward trend of LPG price in Japan over the last 10 years.

The TAGS pipeline passes through Fairbanks and within 140 miles of the gas infrastructure in South-central Alaska. The 50 mmscfd value of in-state gas use is a somewhat arbitrary value for the combined gas usage of communities along the TAGS pipeline route plus potential sales to Alyeska Pipeline Service Company. The capital costs for the TAGS Small Project do not include any gas sales via a spur line to South-central Alaska although this clearly is a potential market. The size of the TAGS Small Project is small enough that in-state gas usage represents a significant portion of total pipeline flow. The project economics will be enhanced if the actual in-state gas demand exceeds the 50 mmscfd value.

The TAGS Small Project is based upon installation of a 30-inch pipeline. This pipeline is oversized for the 1.4 bscfd throughput required to serve the markets mentioned above. The pipeline capacity can be expanded by about 50 percent with the addition of pipeline compression. The benefits of such an expansion are not included in the economic information in the presentation.

Impact on oil production

A premise of the TAGS Small Project is that hydrocarbons currently contained in the miscible injectant stream at Prudhoe Bay will be made available to a gas project. The Prudhoe Bay Unit has stated that the production of miscible injectant for the Prudhoe Bay Miscible Gas Project may cease by around the year 2010. The PBU has also stated that the CO₂ and butane byproducts from the conditioning plant of a gas project can be blended into the MI thereby minimizing or negating impacts on the PBMGP due to a gas project.

A material balance around the conditioning plant proposed for the TAGS Small Project configuration shows that use of the CO₂ and butane byproducts can keep the MI project approximately 90% whole on injectant volume. The adverse impact on the PBMGP is expected to be negligible since: 1) this project will be nearing the end of its life by the start-up of the TAGS Small Project, and 2) the byproducts from the gas conditioning plant can be used to maintain the volume of MI regardless of the project life.

Oil loss attributed to a major gas sale appears to be tied to the amount of gas removed from the reservoir and the corresponding drop in reservoir pressure. One would expect significantly less adverse impact on oil with a gas sale of 1.4 bscfd as compared to the 4+ bscfd volumes discussed for the Canadian pipeline projects.

Oil production at Prudhoe Bay is currently constrained by the gas handling capacity of the production facilities. One would anticipate an increase in near term oil production if the rate of field gas off-take were increased. A premise of the TAGS Small Project configuration is that field gas off-take will be increased with the additional gas disposed of via the gas project.

The increase in crude oil production corresponding to the increase of gas off-take will depend upon the marginal gas oil to ratio of the field. The incremental increase of blendable NGL to TAPS should be roughly proportional to the increase in the rate of gas off-take. No credit has been given to the TAGS Small Project for incremental increases of either crude oil or blendable NGL. It is assumed that the benefits of incremental oil production will be addressed in the negotiation of wellhead gas price.

The impacts on oil production due to the TAGS Small Project have not been included in the economic information in the presentation.

Economic assumptions and models

The information in the presentation is based upon a project-wide process simulation; capital and operating costs prepared for YPC by WillBros, Michael Baker Jr and Kellogg Brown & Root; and YPC in-house software designed to parse capital investments by year of construction. YPC has structured our in-house software to interface directly with the front end of a comprehensive economic model developed for YPC by CS First Boston.

The results of economic models are, of course, dependent upon the assumptions used for the various economic parameters and prices. We believe that our capital cost assumptions are generally conservative in that they tend to overstate the costs. We have run our in-house economic model using product pricing assumptions that we believe are moderate to conservative. Our economic results show that the YPC Small Project configuration returns an IRR near the thresholds stated as acceptable by various parties evaluating a major gas project.

Questions and additional information

Questions regarding this letter or the power point presentation should be sent to:

Ward Whitmore
Director of Project Development
Yukon Pacific Corporation
1400 West Benson Blvd., Suite 525
Anchorage, Alaska 99503

Phone: 907-265-3108
e-mail: wwhitmore@ypc.com

WAW 2-27-02

Yukon Pacific Corporation

- More than 18 years spent developing a gas project from Alaska's North Slope
- Major permits in place
- State-of-the-art analytical tools for pipeline design
- Detailed economic models

TAGS Small Project is a New Concept

- Concept developed during the 4th quarter of 2001
- Promising economics, but in process of verifying premises.

Going Smaller Instead of Bigger

- TAGS current design basis: 36-inch pipeline for up to 18 MTA of LNG (2.5 bscfd) plus in-state gas sales
- TAGS Small Project basis: 30-inch pipeline for 7 MTA of LNG plus ethane and propane sold as separate products; the pipeline can be expanded in the future

Big Projects Gain Economies of Scale, But Make Entry into Market More Difficult

	bscfd
ANGTS	2.5
Highway Project	4.0
ANGTS - Revised	5.2
Highway Project - Revised	6.0
YPC Small Case	1.4

TAGS Small Project - Basic Concept

- Preferentially market the most valuable gas hydrocarbons on the North Slope (propane and ethane).
- Use a single pipeline to transport a mix of hydrocarbons for separation and sale to various end markets.
- Serve multiple small markets simultaneously thereby enhancing economics by avoiding capacity ramp-up.

Three Products to Six Markets

- Methane
 - LNG to Asia
 - LNG to North America
 - Utility grade gas within Alaska
- Ethane (extract from pipeline gas)
 - Feed to Alaskan petrochemical industry
- Propane (extract in Valdez)
 - LPG (liquefied petroleum gas) to Asia
 - LPG to Alaskan communities

Relative Value of North Slope Reserves (From High to Low Value)

- Crude Oil and Condensate
- Natural Gas Liquids
- Propane
- Ethane
- Methane (Natural Gas)

Market Quantities

	<u>mmscfd</u>	<u>1000 Bbl/day</u>	<u>Million tons/yr</u>
In-state gas	50		0.36
LNG to N. America	280		2
LNG to Asia	710		5
Ethane feedstock		60	1.25
Propane as LPG (*)		75 / 50	2.21
Total			10.8

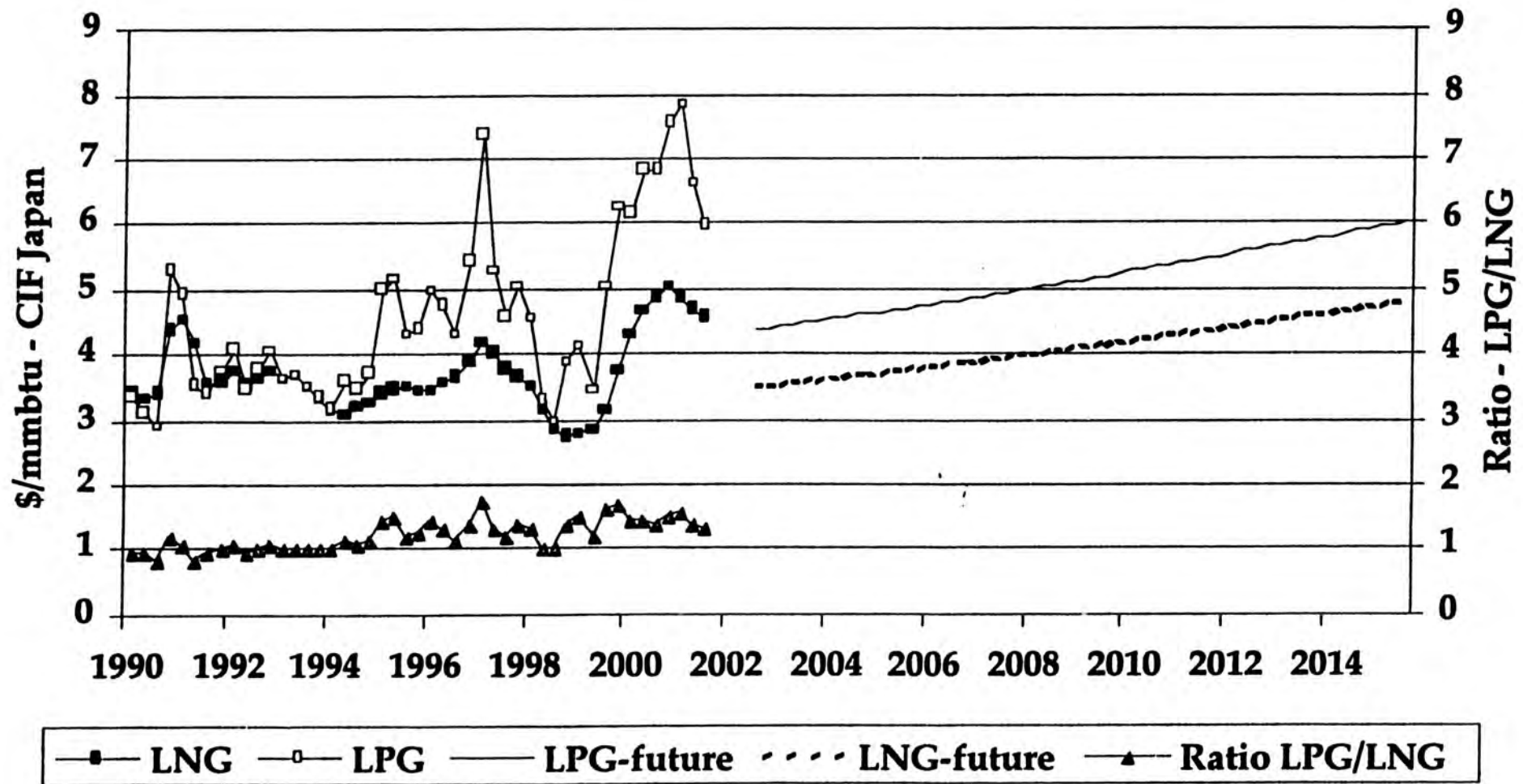
* LPG rate assumed to decline from 75,000 to 50,000 Bbl/day

Why is propane preferable to methane?

- Heating value of propane is 2.5 times that of methane.
- LPG commands a 125% price premium to LNG sold to Japan.
- Each standard cubic foot of propane transported by pipeline will provide more than 3 times the revenue of methane.
- Propane is more easily handled than LNG.

LNG & LPG Prices

(Reference for historical: Sumitomo Corp.)

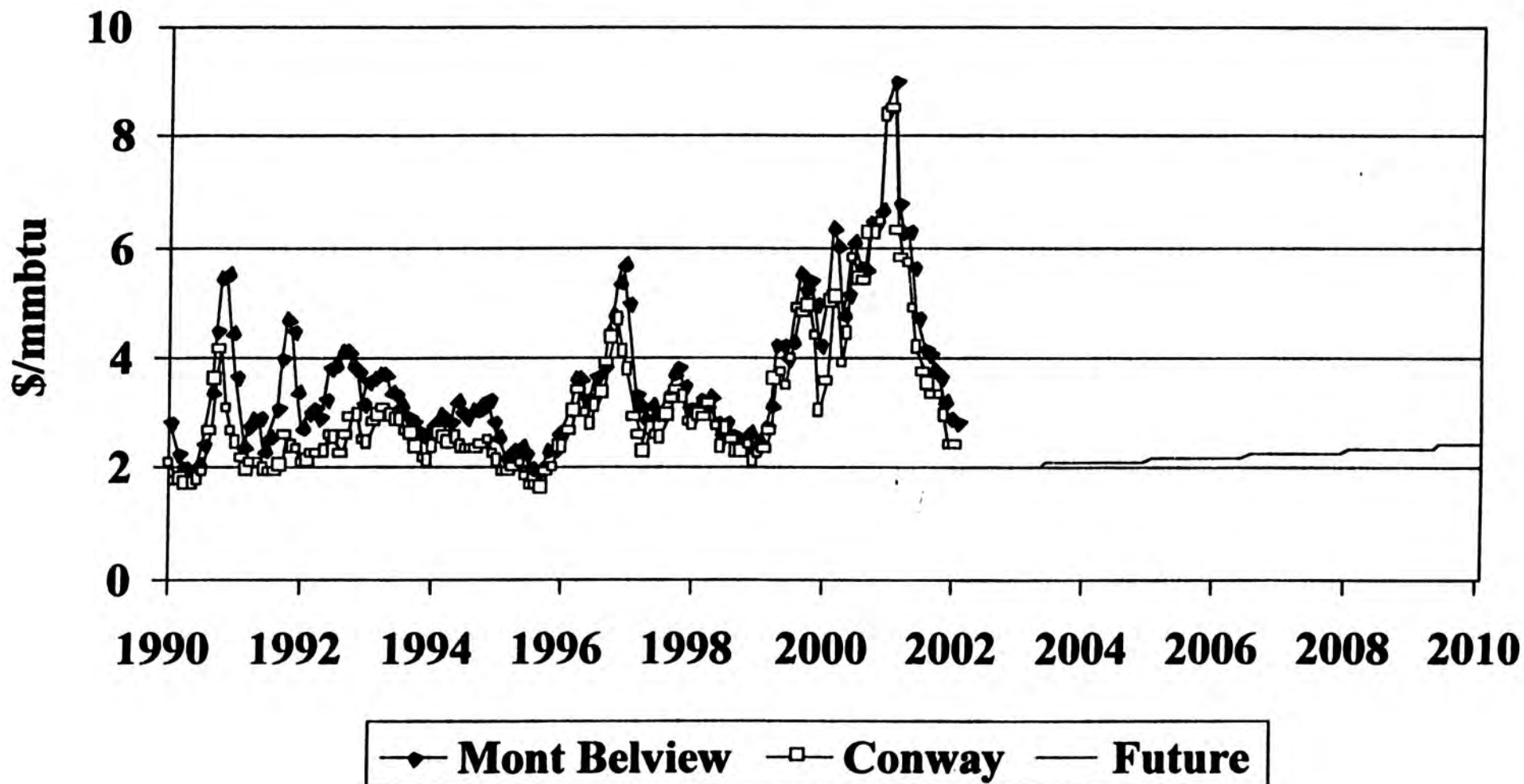


Why is ethane preferable to methane?

- Heating value of ethane is 1.7 times that of methane.
- Ethane is easily removed along with propane.
- Ethane can be sold in-state thereby providing a value-added product for a petrochemical industry in Alaska while minimizing project capital cost.

Ethane Prices in Lower 48

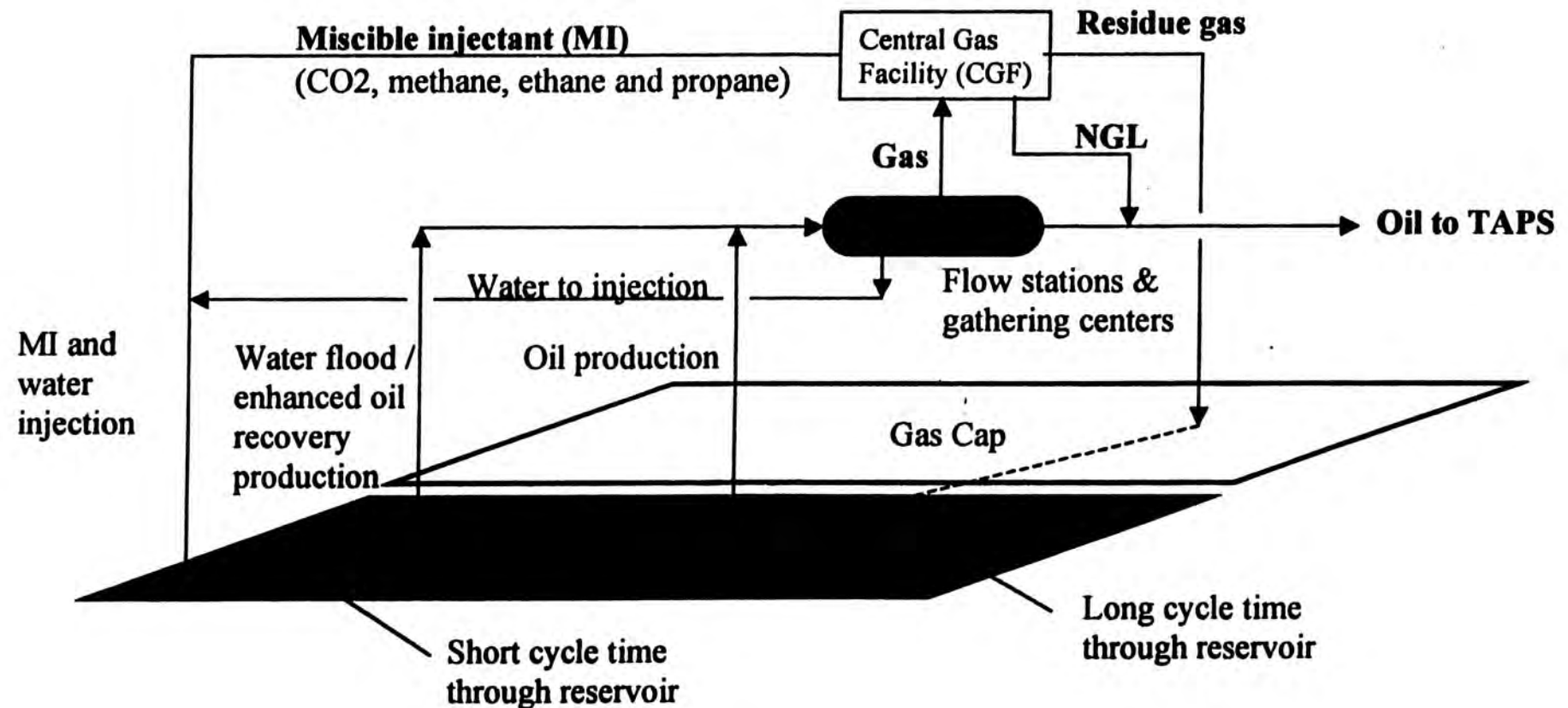
(Reference for historical: Platts)



Sources of gas

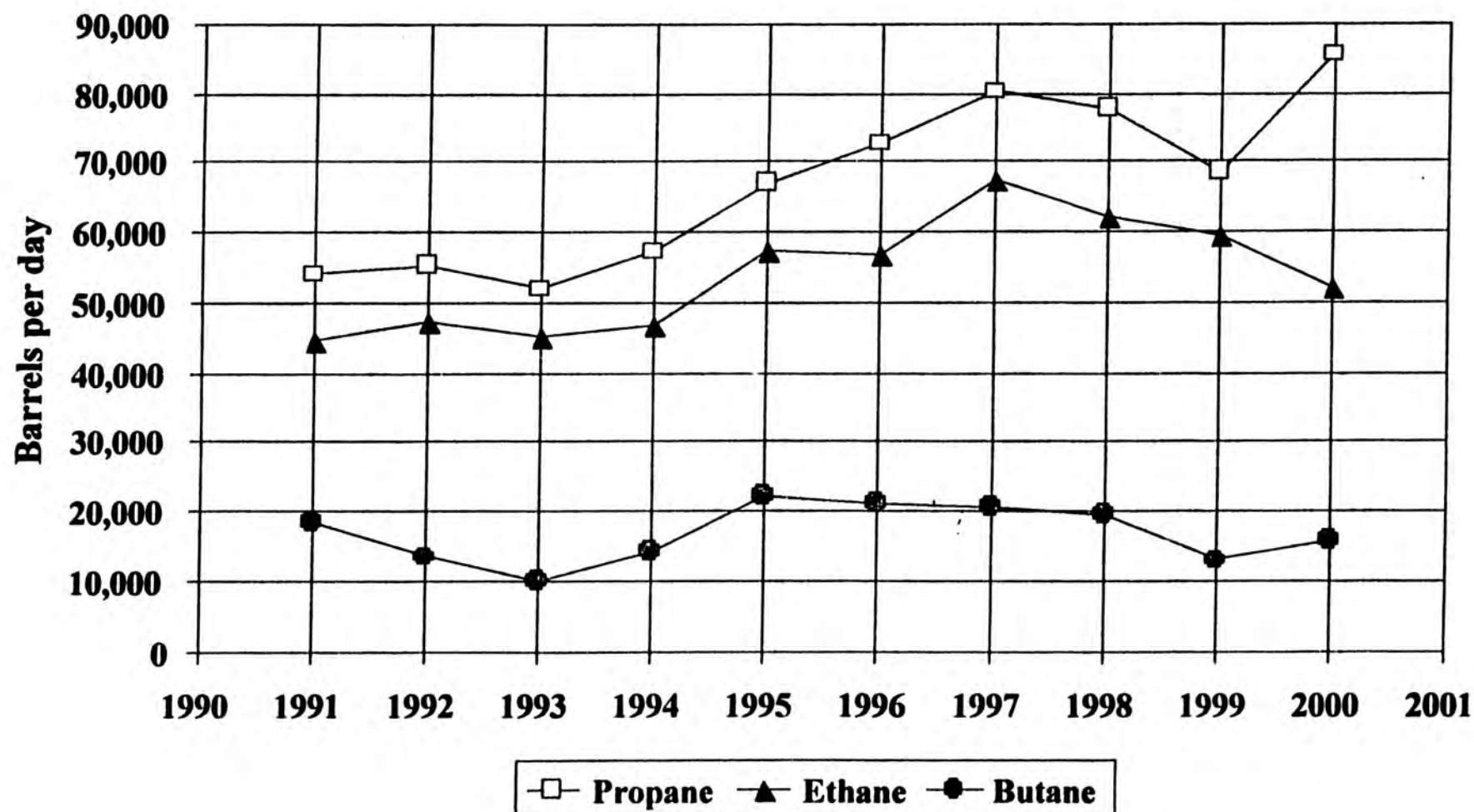
- NGL rich (raw) field gas
 - Assumed source is from Prudhoe Bay
 - Any gas rich in ethane and propane will do
- Miscible injectant at Prudhoe Bay
 - Central Gas Facility concentrates ethane and propane from 8.5 bscfd of field gas
 - Need for MI expected to diminish after 2010
 - CO₂ and butane byproducts from TAGS gas conditioning can supplement MI

Over time, ethane and propane concentrations in the Prudhoe Bay miscible injectant have increased due to recycling through the reservoir



Liquids injected as MI at Prudhoe Bay

(Reference: Alaska Oil & Gas Conservation Commission)



Calculation of Stabilizer Overhead

	<u>Total</u> <u>MI 2000</u>	<u>CGF</u> <u>Residue</u>	<u>Stabilizer Overhead</u> <u>Unadjusted</u>	<u>Adjusted</u>
mmscfd	546	96	450	
<u>Mole %</u>				
CO2	20.76	11.55	22.72	22.69
Nitrogen	0.00	0.62	-0.13	0.00
Methane	36.13	80.74	26.61	26.58
Ethane	14.96	5.14	17.05	17.03
Propane	23.86	1.56	28.62	28.58
I-butane	1.77	0.12	2.12	2.12
N-butane	2.09	0.19	2.50	2.49
Pentane+	0.43	0.08	0.50	0.50
Total	100.00	100.00	100.00	100.00

References:

1 – Total MI from Annual Reservoir Surveillance Report, PBU, Jan. through Dec. 2000.

2 – CGF residue gas composition and 450 mmscfd overhead volume from AOGCC hearings on PBU, 1995.

Gas Sources - Composition

	<u>Stabilizer overhead</u>	<u>Raw field gas</u>	<u>Available mmscfd</u>	<u>bbl/day</u>	<u>Destination</u>
mmscfd	450	1,500			
<u>Mole %</u>					
CO2	22.69	12.07	283		MI
Nitrogen	0.00	0.57	9		Gas/LNG
Methane	26.58	76.11	1,261		Gas/LNG
Ethane	17.03	6.11	168	106,900	LNG/petrochem
Propane	28.58	3.07	174	114,200	LPG
I-butane	2.12	0.41	16	12,200	MI
N-butane	2.49	0.83	24	17,700	MI
Pentane+	<u>0.50</u>	<u>0.83</u>	<u>15</u>	12,700	NGL to TAPS
Total	100.00	100.00	1,950		

References:

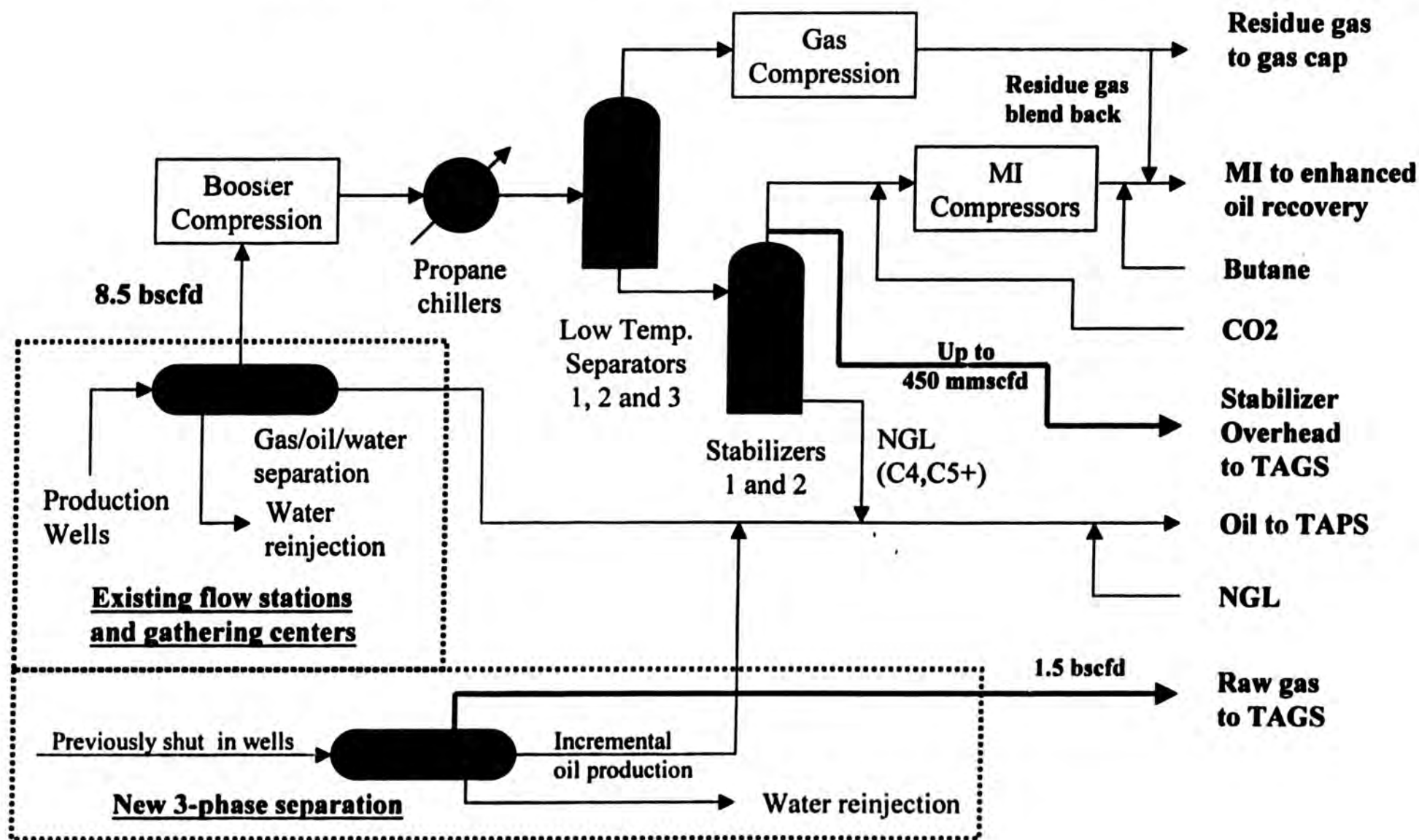
1 – Raw gas composition from AOGCC hearings on PBU, 1995.

Liquids Available from Central Gas Facility

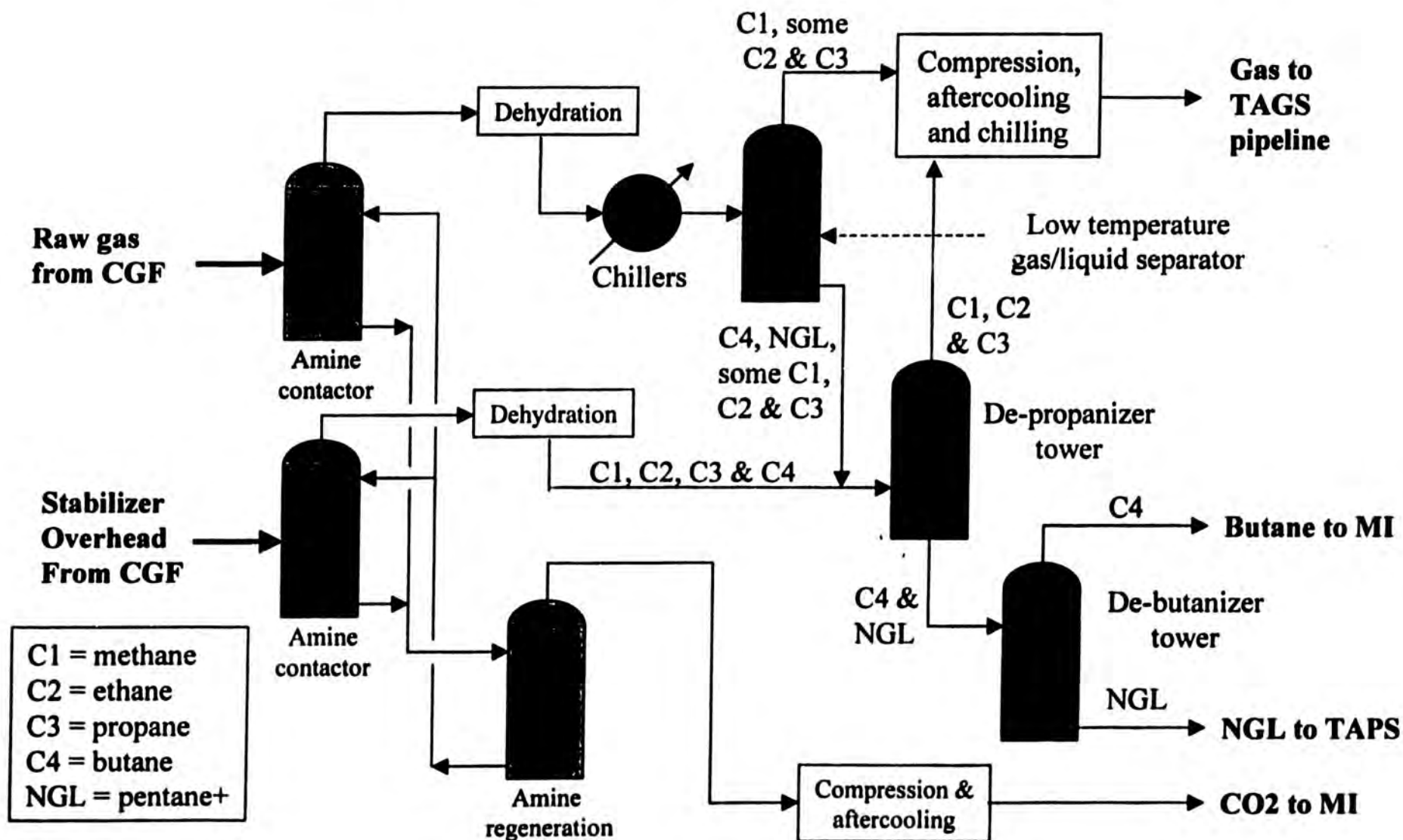
	Stabilizer overhead	Raw field gas	Total
mmscfd	450	1,500	
<u>Bbl/day</u>			
Ethane	48,700	58,200	106,900
Propane	84,100	30,100	114,200

How do we obtain these
products with minimal
impact on oil production?

Central Gas Facility – modified for TAGS



TAGS - Gas Conditioning Plant



PBU Comment on a Major Gas Sale

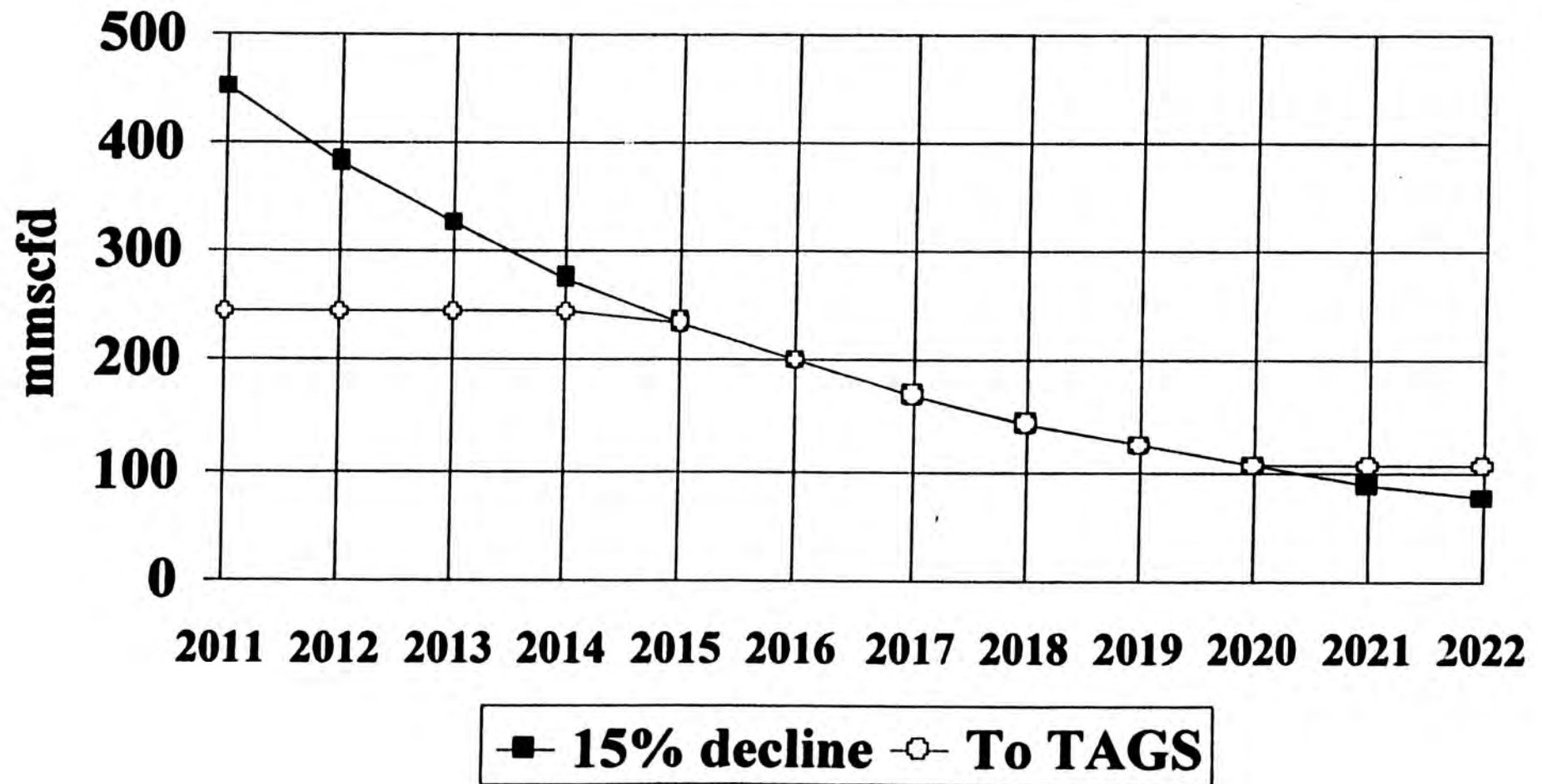
“...That conditioning plant may also reject some butanes, so the CO₂ and butane, if that were coming back, may be able actually to help make up for any loss in MI supply due to the need to increase enrichment, due to pressure decline, or due to the loss of the gas stream itself, so in – reality, the impact could range from small to none...”

ARCO, 1991

Reference: AOGCC hearing, PBU – Miscible Gas Project Expansion, 11/20/91

Stabilizer Overhead Flow Rate

(Availability of ethane and propane assumed to drop over time)

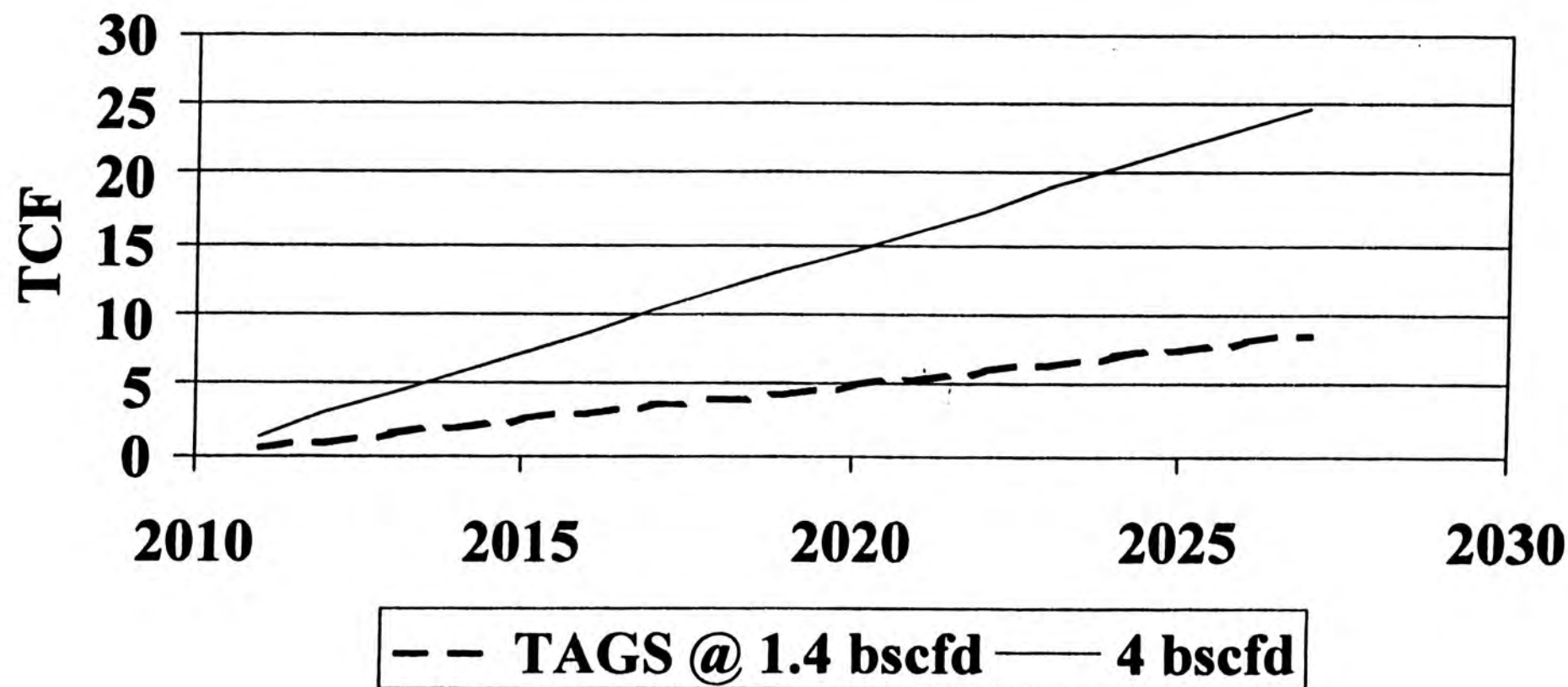


Example: Re-blending of MI

	<u>Excess Overhead</u>	<u>CO2</u>	<u>Butane</u>	<u>CGF Residue</u>	<u>New MI</u>	<u>MI 2000</u>
mmscfd	205	238	31	18	492	546
MMP(*)	2623	4239	-1064	8361	3256	3259
<u>Mole %</u>						
CO2	20.69	100.00		11.55	58.35	20.76
Nitrogen	0.00			0.62	0.02	0.00
Methane	26.58			80.74	14.01	36.13
Ethane	17.03		0.01	5.14	7.27	14.96
Propane	28.58		7.21	1.56	12.40	23.86
I-butane	2.12		33.55	0.12	2.99	1.77
N-butane	2.49		57.23	0.19	4.63	2.09
Pentane+	<u>0.50</u>		<u>2.00</u>	<u>0.08</u>	<u>0.34</u>	<u>0.43</u>
Total	100.00	100.00	100.00	100.00	100.00	100.00

* MMP = minimum miscibility pressure

Larger Gas Projects Increase the Potential for Impact on Oil Production (Cumulative Reservoir Voidage)



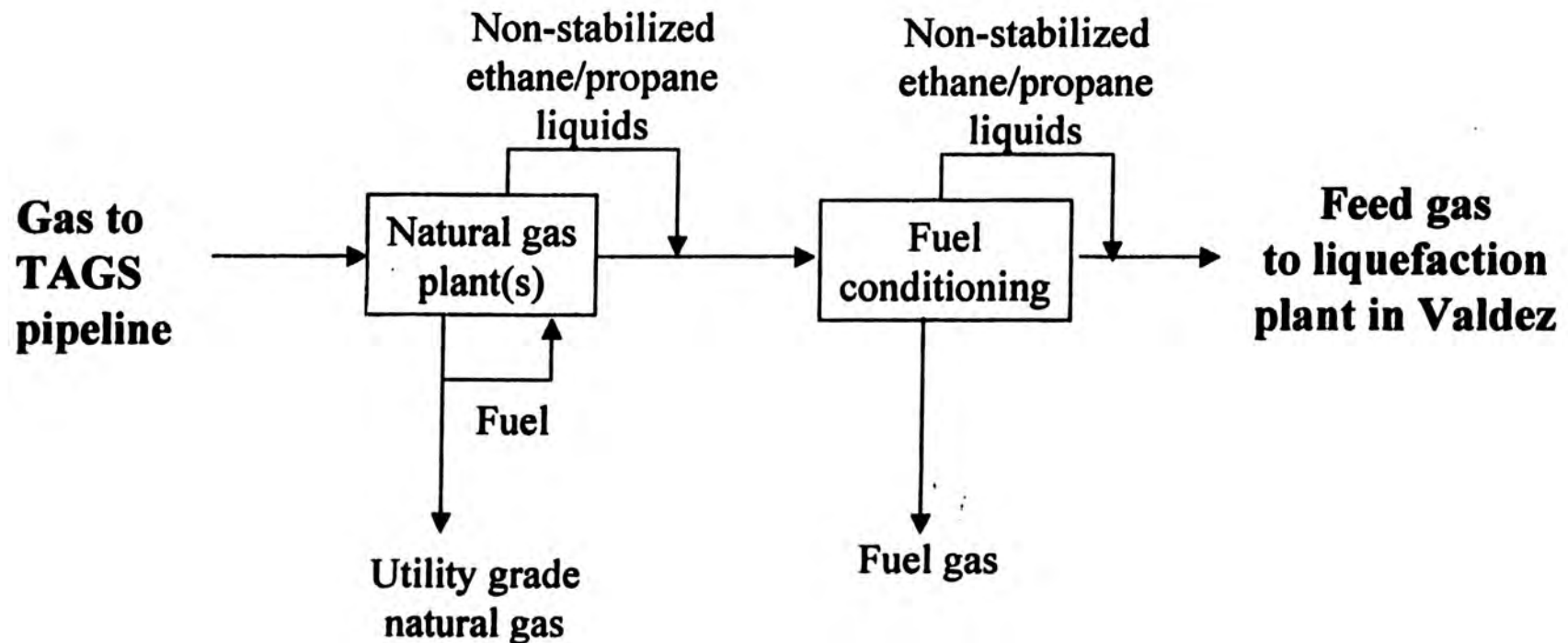
Potential Gain In Oil Production

- Crude oil production at Prudhoe Bay is constrained by the ability to handle gas produced with the oil.
- Gas projects could increase crude oil production - example
 - Current Prudhoe Bay gas/oil ratio is 16,000 scf/bbl
 - Assume marginal GOR of 45,000 for new wells
 - Assume 1.5 bscfd raw gas per YPC Small Project
 - Theoretical increase in crude oil = 33,300 bpd
 $(1,500,000,000 / 45,000 = 33,333)$
- Recovered NGL (C5+) to TAPS = 12,000 bpd

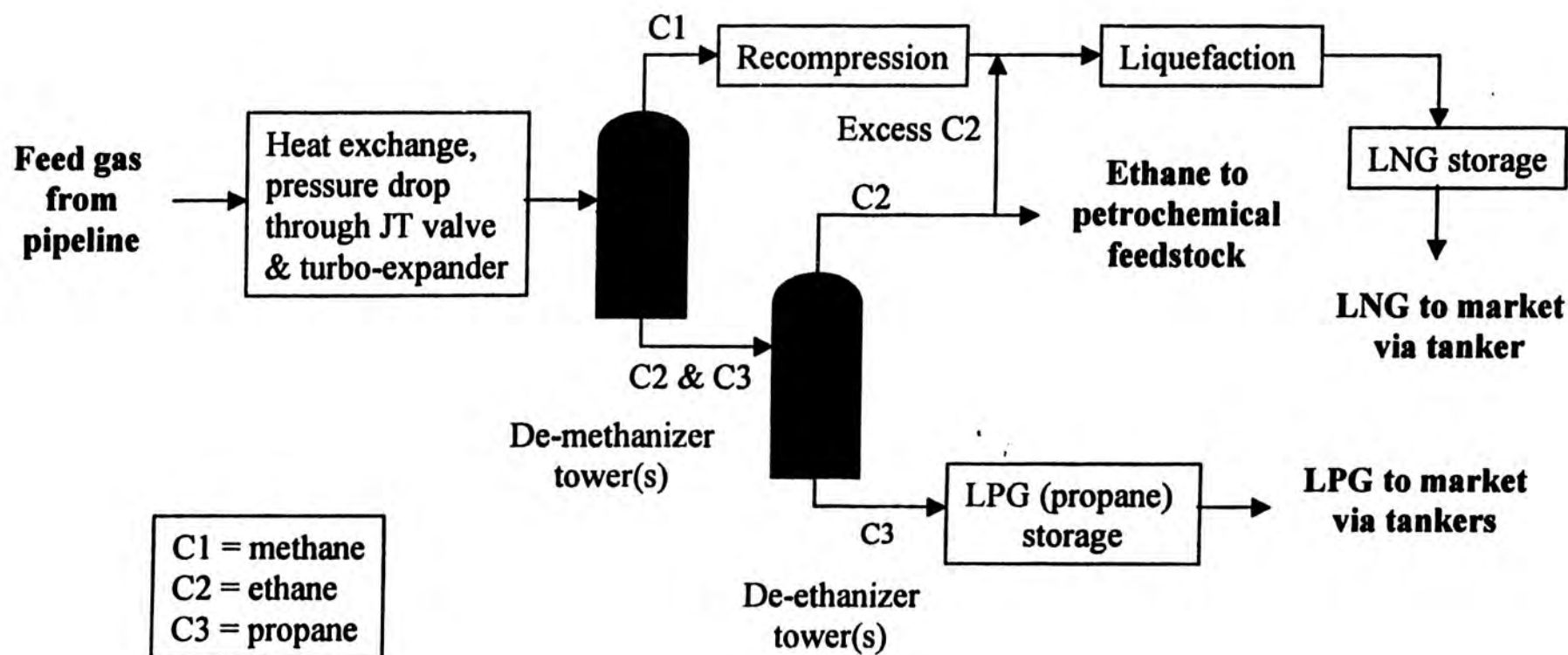
Impacts On Oil Production From TAGS Small Project

- Miscible injectant / EOR: minimal impact expected during remaining life of EOR project.
- Impacts due to drop in reservoir pressure: less drop with smaller project.
- Increasing gas off-take should increase near term oil production (crude oil and NGL).

TAGS – Pipeline, Stations, In-state Gas



TAGS – LPG/LNG/Terminal Facility in Valdez



Market Quantities and Product Prices Used for Economics

	<u>mmscfd</u>	<u>1000 Bbl/day</u>	<u>Million tons/yr</u>	<u>2002 \$/mmbtu</u>
In-state gas	50		0.36	2.50
LNG to N. America	280		2	2.75
LNG to Asia	710		5	3.50
Propane as LPG (*)		75 / 50	2.21	4.38
Ethane feedstock		60	1.25	2.00
Total			10.8	

* LPG rate assumed to decline from 75,000 to 50,000 Bbl/day

Capital Costs Estimates

Gas Conditioning Plant

ANS LNG + \$500 million for
compression and NGL
extraction

Pipeline & Stations

Willbros/M.Baker for 36-inch
adjusted to 30-inch

LNG/MT

Kellogg Brown & Root + \$500
million for C2 & C3 extraction

Tankers

- 7 LNG (135,000 cu.m.)

\$175 million each

- 3 LPG (85,000 cu.m.)

\$125 million each

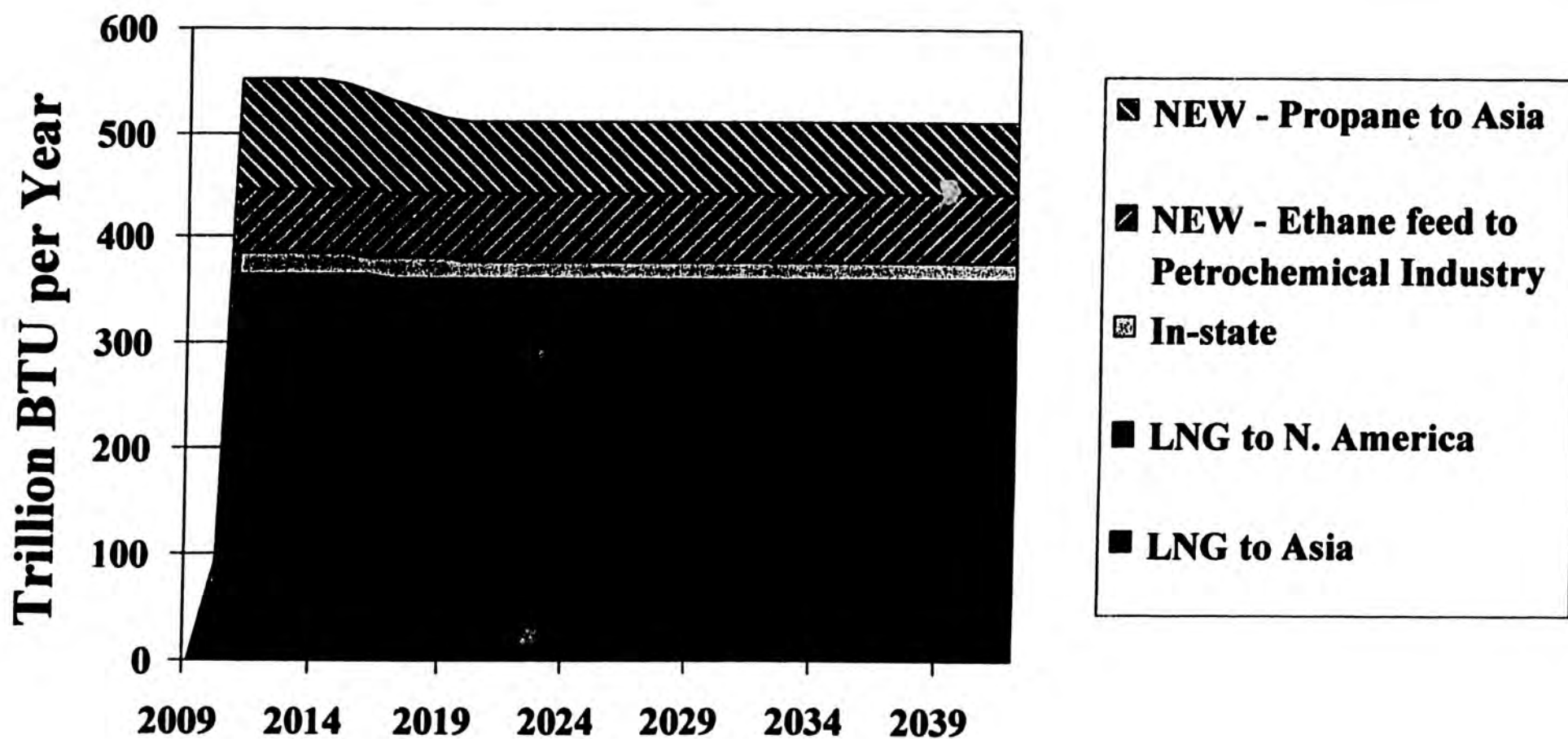
Comparison with Prior Costs Estimate

	ANS LNG group (*)	TAGS Small Case
Bscfd conditioned gas	1.1	1.4
Capital costs (\$billion)		
GCP	0.9	1.5 (1.0 + 0.5)
30-inch pipe & stations	2.4	3.3
LNG - Valdez	1.8	3.0 (2.5 + 0.5)
Tankers (7 ANS, 10 TAGS)	1.6	1.6
Misc. & rounding		0.1
Total	6.7	9.5

* Alaska North Slope LNG Project (recently disbanded)

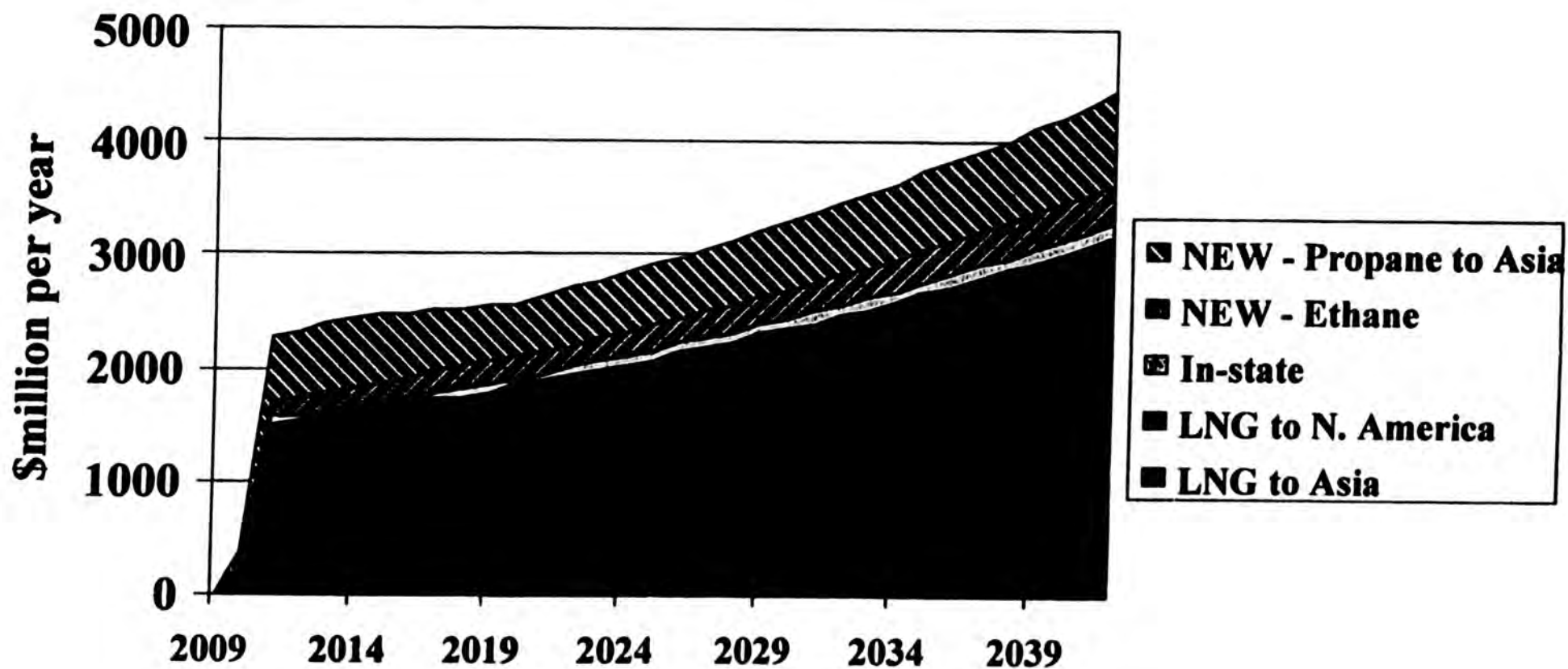
TAGS Small Project

7 MTA of LNG + New Products

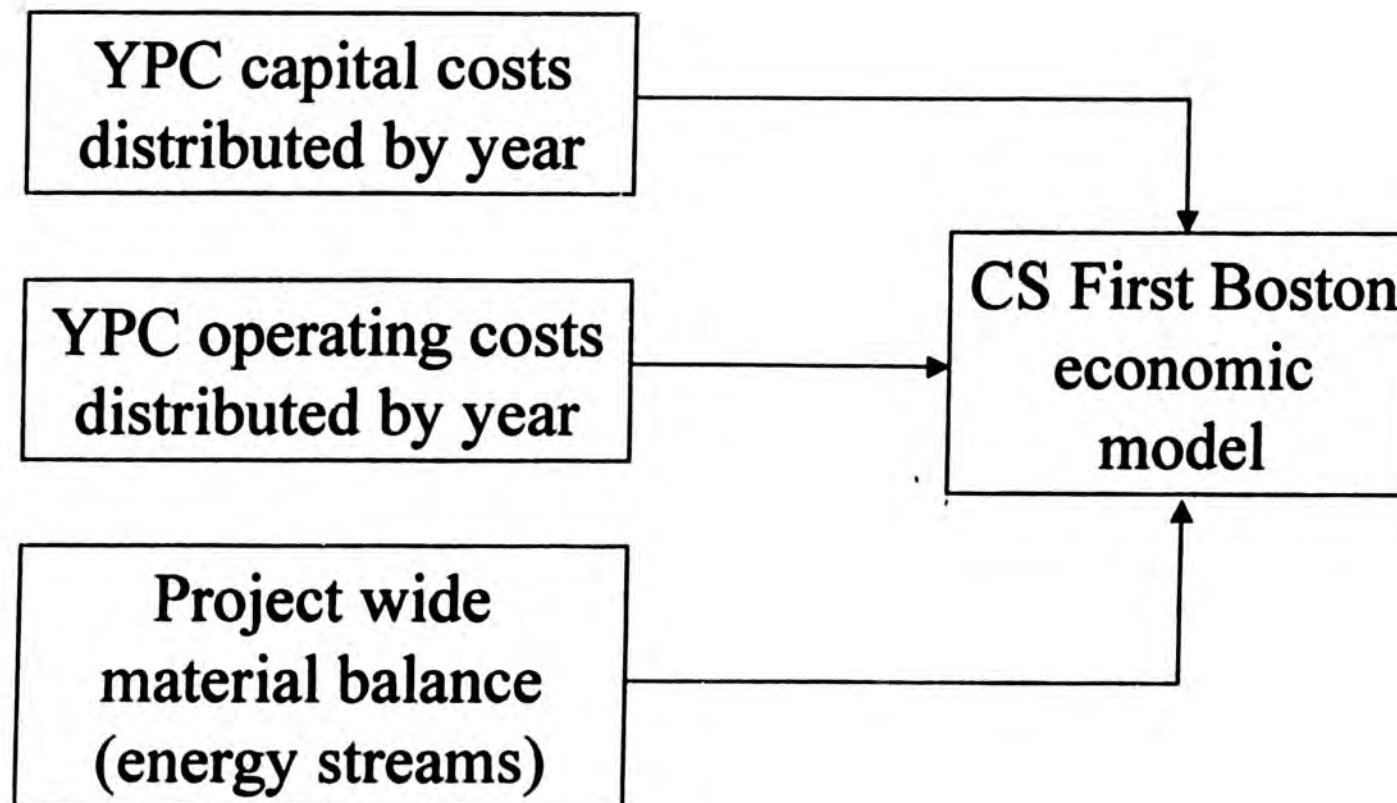


TAGS Small Case - Gross Revenues

7 MTA + New Markets



YPC Economic Model



Economic Premises

- Debt to equity ratio – 75/25
- Interest rate for construction and debt service – 8%
- Inflation – 2.5%
- Gas purchase price - \$0.50/mmbtu at inlet to gas conditioning plant (Reference: CERA December, 2001)

TAGS Small Project Economics

Internal Rate of Return (%IRR)

	Infrastructure Only	Including Net Gas Purchase Revenue (*)
15% LPG decline	11.8%	14.8%
No LPG decline	12.7%	15.6%

* Includes gas purchase revenue net after royalty, severance and taxes.

Next Steps

- Determine economics/viability of petrochemical plant.
- Verify LPG market in Asia.
- Obtain data from Prudhoe Bay Unit
 - Forecast of compositions and rates of stabilizer overhead and raw field gas
 - Potential interface with existing equipment
 - Potential increase in near term oil production

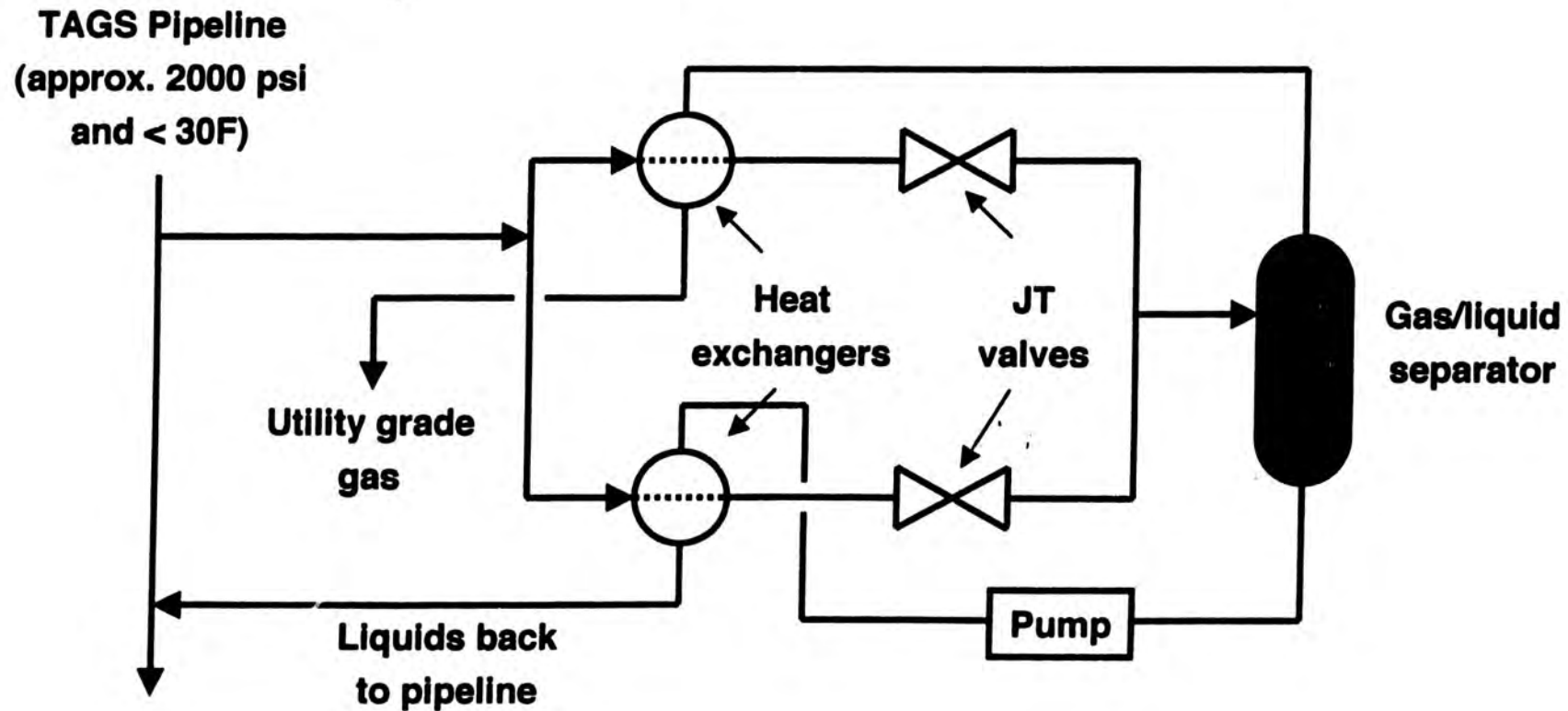
Small Project Now DOES NOT Preclude Other Projects Later!

- The YPC small project requires relatively little of the North Slope methane resource.
- There will be plenty of methane left to supply pipeline projects through Canada to Lower 48.
- There should be no impact on a gas-to-liquids project.

Gas Accessible for In-State use with Minimal Capital Cost

- Conditioned gas will be free of CO₂ and dry.
- No further gas pre-treatment required.
- Gas facilities along the pipeline will be simple and inexpensive.

Simplified Schematic of In-State Gas Facility



Why Is YPC Looking at a Smaller Project?

- Lowers capital costs
- Enhances market entry
- Provides means to market most valuable gas components remaining on the North Slope
- Uses enhanced project revenues to establish gas infrastructure/industry within Alaska

Conclusion: Alaska Should Keep Its Options Open

**State and/or Federal assistance MUST
apply to all projects.**

YPC is ready to work with all
parties interested in developing
Alaska's North Slope gas.

Ward A. Whitmore
Director of Project Development

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Phone: 907-265-3108
wwhitmore@ypc.com

ALASKA GAS STUDY ASSUMPTIONS FOR FAIR AND USEFUL COMPARISONS

When a comparative analysis is done, it is important that the assumptions of the various cases are treated in a similar manner in order to ensure that the final product is a fair representation of the facts and that it will actually be useful for making decisions. Listed below are some principles which should be used in comparing the alternatives for Alaska gasline options.

1. If tax breaks or price supports are considered for one project, they should be assumed to apply to all.
2. In supplying the US with Alaskan natural gas, overland routes and LNG delivery should be treated equally. If the US market can accommodate 4.5 billion cubic feet per day, it could also accommodate large scale LNG deliveries to the US west coast. That would allow the diversion of Rocky Mountain and other gas to the Midwest and eastern markets.
3. The ramp up rates need to be treated in a similar manner, or if they are not, substantiated evidence should be supplied to justify the difference. For example, if an overland route is assumed to operate immediately at full production of 30 million tons per year, and the LNG project is assumed to ramp up at only 2 million tons per year (Roger Mark's model) that would be a totally false comparison.
4. The projects analyzed should be those as described by the proponents of the projects, and cost estimates they have completed should be reviewed and used for the analysis.
5. Gas to liquids (GTL) analysis should be considered both on the North Slope and at tidewater, with consideration given to the effect of tidewater GTL production on the economics of the delivering pipeline.
6. The use of natural gas products other than methane, such as the Williams proposal for an ethane base,¹ petrochemical plant and other possible products should be included in the analysis.
7. The impacts of the various projects on oil production should be included in the analysis.
8. The analysis should compare the cost difference of the various projects in delivering North Slope natural gas to Southcentral and coastal Alaska.

Perhaps these are not completely the correct guidelines for this study, but it seems these would be a useful starting point for a discussion on what the assumptions should be on the front end of the study rather than criticizing it later when it is done and the money has already been spent.

Supplied by Yukon Pacific Corporation

MONEY

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SATURDAY, MARCH 9, 2002

BUSINESS IN BRIEF

ENERGY

Marathon to build pipeline, plant in Baja

MEXICO CITY — Eyeing an attractive market for gas and electricity in California and northwest Mexico, Marathon Oil Co. formally joined the ranks of major energy companies seeking to build natural gas installations in Baja California. At a meeting with Wall Street securities analysts last week, the Houston-based company confirmed a Los Angeles Times report that it had secured a site in Playas de Tijuana south of the U.S.-Mexico border. Its complex would include a liquid natural gas terminal, regasification and storage facilities, a pipeline to U.S. and Mexican markets, and a 400-megawatt electric power plant.