

**SUBMISSION OF  
PARAMOUNT ENERGY OPERATING CORP.  
TO  
ALBERTA ENERGY AND UTILITIES BOARD  
REGARDING  
GENERAL BULLETIN GB 2003 – 12  
GAS PRODUCTION IN OIL SANDS AREAS**

**INTRODUCTION**

On April 3, 2003, the Alberta Energy and Utilities Board (the "Board") issued General Bulletin GB 2003-12 which invites interested parties to provide written submissions regarding:

- 1) whether existing gas production from the Wabiskaw-McMurray Formation in the Athabasca Oil Sands Area should be shut-in, and/or
- 2) any alternative measures that might be taken to ensure the conservation of bitumen in the Wabiskaw-McMurray Formation in the Athabasca Oil Sands Area.

Paramount Energy Operating Corp., as the trustee of Paramount Operating Trust and the administrator of Paramount Energy Trust (collectively "Paramount") makes this submission as an interested gas operator. Paramount is the fourth largest producer of gas from the Wabiskaw and McMurray Formations in the Athabasca Oil Sands Area (the "WM"). As approximately 70 percent of Paramount's total production comes from the WM, any future decisions with respect to gas production in the WM will impact Paramount and its beneficial Unitholders. We strongly request that the Board give consideration to the catastrophic impact on gas producers and the Province of Alberta which could result from rapid changes to the established process regarding gas/bitumen co-production within the WM.

**INTERPRETATION OF GB 2003-12**

It is the interpretation of Paramount that the intent of GB 2003-12 is to gather information from industry which will assist the Board in prioritizing specific areas for future assessment of grandfathered wells. Because there are no pending applications for shut-in before the Board, the Board has no defined priority for addressing grandfathered

wells, except as recently identified in the Chard/Leismer decision. By seeking input from industry, and particularly bitumen owners, in determining the specific areas within the WM where the production of gas might be considered to present a significant risk to bitumen conservation, the Board can move to develop a prioritized list of grandfathered wells to address and proceed with a fair and reasonable process.

It is Paramount's interpretation that GB 2003-12 is not a request to furnish relevant technical or other evidence to the Board with respect to a pending decision to shut-in gas production from the WM. As a gas producer, the basis of Paramount's submission is a discussion of the process to be implemented to address grandfathered gas production.

### **1.) WHETHER EXISTING GAS PRODUCTION FROM THE WABISKAW-MCMURRAY FORMATION IN THE ATHABASCA OIL SANDS AREA SHOULD BE SHUT-IN**

It is Paramount's position that existing gas production from the WM should not be shut-in except following an application and pursuant to a fair and reasonable process which ensures that existing gas production that meets the relevant criteria continues uninterrupted.

Paramount believes that the current process as defined by ID 99-1, with some modifications, has been and will continue to be a fair and reasonable process which protects the rights of natural gas leaseholders and meets the requirements of natural justice, while maximizing the benefits of all resources to the people of Alberta.

#### **Rights of Natural Gas Leaseholders Must be Preserved**

When the leases associated with grandfathered gas production were purchased, market value was paid and investment decisions were made in reliance upon the right to explore for, develop, produce and bring to market natural gas in accordance with the existing regulatory framework. Notwithstanding the fact that when leases were issued they were expressly subject to changes in law and changes in the regulatory regime; precedents indicate that any such changes will be implemented in such a way as to provide fair opportunity for leaseholders to address these changes and adjust their investment decisions accordingly.

The Gas/Bitumen Inquiry was held nearly six years ago, and as a result ID 99-1 was issued February 3<sup>rd</sup>, 1999. From this point in time gas producers have relied on the process contained in ID 99-1 and any change would come as a significant deviation from this established framework. If any existing gas production that meets what were previously acceptable criteria is unnecessarily shut-in, the magnitude of compensation due the gas producer would be unnecessarily inflated.

### **Process Established Must Meet the Requirements of Natural Justice**

Paramount submits that any process undertaken to determine whether existing gas production from the WM should be shut-in must be:

- a.) fair and reasonable;
- b.) not impose an inefficient and unreasonable regulatory burden on the gas producers, the Board or the people of Alberta.

A process which meets the requirements of natural justice would be one in which existing gas production from any given well would continue unless an application to shut-in specific wells was filed with or by the Board, technically scrutinized, and decided in favor of the applicant following a full oral or written hearing.

### **Adopt ID 99-1 Process to Address Grandfathered Gas Shut-in Applications**

The process established by the Board under ID 99-1 is fair, and meets the requirements of natural justice, although Paramount believes the criteria for approval of gas production as set out in ID 99-1 should be amended. Upon the filing of an application for approval to produce gas or for shut-in of existing production, all interested parties are given the opportunity to present evidence, test the evidence of other parties and make argument. The Board then makes a decision on the application based upon the evidence and argument put before it, having regard to the criteria set out in ID 99-1. If the criteria are met, gas production is allowed.

The recent Decision 2003-23 seems to indicate that the process established to date to address new wells, the process established by ID 99-1, is adequate. The key component of this interpretation is that the Board clearly states in Decision 2003-23 that, 'in the absence of sufficiently complete and conclusive evidence, it does not believe a change to ID 99-1 is warranted and continues to believe that the current application process is appropriate to ensure that potentially at risk bitumen is not jeopardized'.

### **Proposed Amendments to ID 99-1 Process**

With respect to the details of an application to shut-in gas, Paramount proposes that an applicant, whether a bitumen owner or a Board Staff Submission Group, must present a factual submission with supporting evidence. The affected gas producer must be given the opportunity to test that evidence, present its own evidence and provide argument. Paramount proposes that the burden of proof be on the party seeking to shut-in gas. Applications for shut in should include a well-by-well analysis of both the quality of the bitumen opportunity (the extent of the resource and the feasibility of its economic extraction using SAGD) and the risk of producing the overlying gas.

Placing the onus on the shut-in applicant with regard to both assessing the quality of the resource and bringing all available knowledge before the decision-maker is critical for this process to be fair and reasonable.

### **Modified Process Will Provide for Natural Justice**

#### **a.) Fair and Reasonable**

Notwithstanding the fact that a decision could be made adversely affecting the rights of the gas producer, this proposed process is fair and reasonable for all stakeholders.

It is fair for the gas producer because no production is shut-in arbitrarily or in the absence of the relevant technical facts. It is fair for the bitumen owner because it preserves the right to apply to the Board to seek shut-in of gas production where the bitumen owner believes its resource is being adversely affected and the criteria set out in ID 99-1 have not been met. It is mutually fair to all parties because: it allows the owners of both resources to develop those resources free from any arbitrary restrictions on production; it provides for reference to established criteria, set out in ID 99-1, to resolve disputes where there is conflict arising from the concurrent production of both resources; and it allows the Board, through a staff submission group, to file an application for shut-in in appropriate cases where there are concerns whether the ID 99-1 criteria are satisfied and where no application has been made by the bitumen owner or where there is no bitumen owner.

Paramount believes that appropriate cases for the filing of a shut-in application by a Board staff submission group would be rare. It would be unusual for there to be anything more than infrequent occasions in which there would be sufficient bitumen that is commercially exploitable for which either there is no bitumen owner or for which the bitumen owner would not be seeking shut-in of gas production if such shut-in would be required to protect the bitumen. Given that the Board does not have expertise in conducting the required economic analysis to determine if a particular bitumen deposit is commercially exploitable, it may be appropriate for the Board to seek expert advice in determining the commerciality of giving bitumen deposits in the absence of an outside application.

Paramount is of the view that any process that includes an arbitrary shut-in order of any kind, such as a "no-fly zone," would be unfair and contrary to the requirements of natural justice. No production should be shut-in unless it can be established, through a fair and reasonable process as discussed above, and based upon specific evidence acceptable to the Board, that it threatens bitumen production as a result of the criteria set out in ID 99-1 not being met.

#### **b.) Unnecessary Burden**

The process proposed by Paramount would also be efficient since neither industry nor the Board would be burdened with unnecessary applications. In any process involving an arbitrary shut-in, many wells that meet the ID 99-1 criteria would be shut-in

unnecessarily. Presumably, these wells would be allowed to produce again following an application of some sort to the Board. As a result, the gas producer would be burdened with the effort and expense to seek immediate compensation for any shut-in order and also to prepare applications to overturn the shut-in order for all wells that meet the ID 99-1 criteria. Similarly, the Board and the Government would be burdened with these unnecessary applications, wasting valuable resources of all parties.

The people of Alberta would also suffer a loss due to the inefficient use of resources, the arbitrary constraints on the development of the gas resource, the associated interruption of the receipt of production royalties as well as the cost of compensation to the gas producer for the unnecessary shut-in of gas production.

Notwithstanding all of these losses, there would be no benefit whatsoever to the bitumen owner in the cases where the ID 99-1 criteria were met.

## **2) ALTERNATIVE MEASURES THAT MIGHT BE TAKEN TO ENSURE THE CONSERVATION OF BITUMEN**

Paramount is committed to working with the Board, and other stakeholders, to reach a fair and appropriate resolution of the gas/bitumen conflict. Paramount believes that no additional measures are required to ensure the conservation of bitumen, because the issue at the centre of the current gas/bitumen conflict is not the conservation of bitumen *per se*, but rather the conservation of **commercially recoverable bitumen using the SAGD method** of recovery. The gas/bitumen debate has arisen because some bitumen owners have claimed that gas production is detrimental to the ultimate recovery of bitumen using the SAGD method of recovery. Accordingly, to focus on anything other than bitumen that is commercially recoverable is of no benefit to any stakeholder.

None of the gas producers, the bitumen owners, the Board or the people of Alberta benefit when gas is shut-in to conserve bitumen that is not amenable to commercial SAGD production. Gas production is not harmful to the bitumen resource itself. At most, there is a debate regarding whether it is detrimental to commercial SAGD bitumen recovery. Requests for shut-in should only be made where there is actual conflict between production of the two resources, such that neither resource is wasted – gas is not shut-in unnecessarily and bitumen recovery is not compromised. The bitumen owners do not presently use the criteria set forth by ID 99-1 in their determination of what is a commercial SAGD development; however, they do use that criteria when seeking the shut-in of gas production.

### **Status of Knowledge Surrounding the Gas/Bitumen Debate**

It is clear from both Decision 2000-22 and Decision 2003-23 that the Board is not satisfied that it has sufficient information to fully evaluate many key issues that must be resolved in order to determine whether associated gas production actually does have a detrimental effect on the recoverability of bitumen. Issues that require further attention include reservoir repressuring, artificial lift, history-matched reservoir models, the

technical and commercial feasibility of SAGD production and the requirements for economic SAGD production.

It has been over four years since ID 99-1 was developed and nearly six years since the Gas/Bitumen Inquiry was held. There have been significant advances in technology, the industry's knowledge regarding gas production, SAGD production and the economics of bitumen projects. There is also a great deal of field data that is now available, and this data is increasingly available to the public. Projects involving both gas producers and bitumen owners are also underway, such as the Devon/EnCana Christina Lake flue gas injection project. It would be of assistance to all parties to examine if any conclusions can be drawn from the current ongoing bitumen recovery projects in the WM; and if the result of any experimental projects show that cooperative approaches to the gas/bitumen co-production issue are having technical and/or commercial success.

Paramount believes it would be appropriate for the Board and the Department of Energy, to establish a mechanism for ongoing updates to the knowledge base with respect to the gas/bitumen issue to determine on an ongoing basis whether the criteria set out in ID 99-1 continue to be appropriate, and if not, how they should be changed. While the Board and the Department of Energy should encourage participation by all stakeholders, all bitumen owners should be required to submit all SAGD data and relevant documents for consideration under such a mechanism, even where such information is confidential.

Other issues, such as compensation for gas producers where gas is shut-in, gas and water supply for SAGD projects and other thermal recovery methods, should also be addressed. Regulatory process issues, such as streamlined approval for gas production where the appropriate criteria are met, drilling depth requirements and the current moratorium area, are also fundamental to a fair and reasonable solution.

### **SUMMARY**

It is Paramount's position that existing gas production from the WM should not be shut-in except following an application and pursuant to a fair and reasonable process which ensures that existing gas production that meets the relevant criteria continues uninterrupted.

Paramount believes that the current process as defined by ID 99-1, with some modifications as described herein, has been and will continue to be a fair and reasonable process which protects the rights of natural gas leaseholders and meets the requirements of natural justice, while maximizing the benefits of all resources to the people of Alberta.

Paramount is committed to working with the Board, and other stakeholders, to reach a fair and appropriate resolution of the gas/bitumen conflict. Paramount believes that no additional measures are required to ensure the conservation of bitumen.

Paramount recommends that the Board and the Department of Energy establish a mechanism for ongoing updates to the knowledge base with respect to the gas/bitumen

issue to determine on an ongoing basis whether the criteria set out in ID 99-1 continue to be appropriate, and if not, how they should be changed.

Paramount is of the view that adoption of these proposals would be a significant step forward in resolving gas/bitumen issues. Paramount looks forward to working with the Board and other interested parties to resolve the current issues through a fair and efficient regulatory process. Paramount encourages the Board to contact it if it would like clarification or amplification of any issues raised in this submission, or comment on the submissions of other parties.

Dated this 12<sup>th</sup> day of May, 2003

PARAMOUNT ENERGY OPERATING CORP.  
as trustee of  
PARAMOUNT OPERATING TRUST and  
administrator of  
PARAMOUNT ENERGY TRUST

Susan L. Riddell Rose  
President

**Presentation to the EUB Re: GB 2003-16  
For Paramount Energy Trust, July 3, 2003  
Dr. John Shiry, President, Woodside Research Ltd.**

## **Introduction**

I am Dr. John Shiry here as an expert witness on behalf of Paramount Energy Trust. I want to summarize for you a Report I prepared for Paramount that **estimated** the cumulative impact of the proposed shut-in of gas production in over 5.5 million acres in the Wabiskaw-McMurray bitumen region. I have a long record of completing important research on this industry that includes:

- A study of the impact of changes to the Alberta Royalty Tax Credit for the old IPAC.
- A study of the impact of the Large Corporations Tax on small and mid-sized companies' capital spending, also for IPAC.
- A study of the total tax burden by all levels of government on the upstream petroleum sector for CAPP.
- Two studies of industry profitability, compared to other Canadian sectors and to the U.S. oil and gas industry for CAPP.
- Studies of the emerging "midstream business" for two different utility clients.
- A study of "Value Creation in Royalty Trusts" for one of the pioneer oil and gas trusts.
- I have spent much of the past five years focused on commodity prices, and this has resulted in some of the most important forecasts of major oil and gas market turning points (the oil price collapse of 1997-1998, the sharp recovery of 1999, the prospect of continued prices above US \$25/barrel, the artificial gas price spike of 2000-2001 and the "inevitable price recovery of 2003").

My PhD is in political science and I specialized in public policy and social research. These are my most relevant credentials to appear as an expert witness. I also wrote many columns for the Financial Post in the early 1990s and continued to write for Oilweek and contributed to The Oil & Gas Investor. I bring a very broad understanding of the oil and gas industry to this current research.

## **The Research Before You**

The research created a series of scenarios showing the projected cumulative revenue, royalties, operating costs, capital spending and corporate taxes over the last five months of 2003 and the next 15 years. These estimates are all based on realistic assumptions and are believed to be conservative; losses are likely to exceed these estimates. **No value has been estimated for the stranded costs of infrastructure or for the premature decommissioning of wells and facilities.**

Our different scenarios are based on either blow-down production profiles (what would production be if capital spending were halted), and, for comparison, continued investment under **ID 99-1** rules in place until June 3, 2003 (producing an estimated 6% annual decline). The start-point is an estimated 230 mmcf/day for 2003. It is worth noting that *before* the Board imposed the restrictions in **ID 99-1**, gas production for the entire northeast region (PASC Area 6) was at 1.2 bcf/day and was forecast to rise to 1.4 bcf/day. This Area 6 includes the Wabiskaw-McMurray area but is much larger. Gas production in Area 6 has fallen to about 700 mmcf/day, and this proposed shut-in order would cut that again to about 470 mmcf/day. It is clear that EUB decisions have already impaired gas production in Northeast Alberta, though some natural decline is also at play.

Under the “best” and “worst” scenarios, lost industry revenue ranges upward from \$3.2 billion to \$4.8 billion. The province loses between \$670 million and \$1 billion in royalties. Lost cash flow would be between \$2.0 billion and \$3.1 billion. Most of this cash flow would normally be re-invested in Alberta or other parts of the basin. Some 20% would have been re-invested in the NE region under the development rules in place just one month ago (**ID 99-1**). The impact on that region is expected to be dramatic and pervasive.

In the various scenarios, the affected region loses between \$500 million and \$980 million in operating costs and another \$405 million to \$515 million in future development spending that would have taken place under the restrictions of the Board’s **ID 99-1** rules. The direct economic impact on the region is between \$900 million and \$1.5 billion. Lost economic activity on this magnitude will have a ripple effect through the local economies that is even larger than this data.

Let me be specific by summarizing some of the scenarios we modeled.

### **Summary of Findings** (pages 1-4 and 8-14)

(These page references are to my June 25, 2003, Report: **Estimate of Financial Losses and Socio-Economic Impacts From Implementation of EUB GB 2003-16**, submitted to the Board as part of Paramount’s submission).

Our first 3 scenarios (found after page 18 of my Report) show these losses under different price schedules and assuming no capital spending were allowed from the present; a blow-down scenario.

**Scenario 1** shows the most conservative price outlook, with prices actually falling to \$4.65 (about US \$3.50) for 2007 then rising 10¢ each year through 2018.

- Cumulative Lost Revenue is \$3.2 billion
- Lost Field Cash Flow is \$2.0 billion (essentially “field net-backs”. For use here, we do not include company administrative and interest costs or cash taxes at the corporate level)

- Lost Royalties are \$674 million
- Lost Operating Costs in the Region (assuming these remain flat at 85¢/mcf) are \$507 million
- Lost Capital Spending in the Region (at 20% of Field Cash Flow) is \$406 million
- Lost Operating Costs and Capital Spending in the Region are a **direct loss of economic activity in the affected area totaling \$912.9 million**
- Lost Corporate Income Taxes (also at 20% of Field Cash Flow) are \$406 million.

**Scenario 2** shows slightly larger losses under a more optimistic price scenario. We believe the McDaniel price deck is very conservative. Few analysts expect gas prices to decline to US \$3.50/mcf over the next five years. This “medium” price model uses McDaniel for 2003 and 2004, then flat prices at \$5.65/mcf for the remaining 14 years. This is roughly equivalent to U.S. prices at US \$4.25/mcf and a 75¢ dollar.

Many analysts see the clearance price for gas over the medium term at US \$4.00 to \$4.50/mcf; we have simply applied the mid-point of this range. In this scenario, revenue is slightly higher and as a result, so are royalties, field cash flow, assumed corporate taxes and field capital spending (both at 20% of field cash flow). The results for **Scenario 2** are shown in the tables (after page 18).

**Scenario 3** shows the most aggressive price outlook, with prices at \$7.00 for 2004 then flat at \$6.40 each year through 2018 (US \$4.50/mcf and a 70¢ dollar). This is the prospect suggested by some analysts who point to ever growing use of gas for space heating, electric utility plants and some for transportation (the fuel cell) even as petrochemical and fertilizer production moves offshore to low-cost sources of natural gas.

- Cumulative Lost Revenue is \$3.9 billion
- Lost Field Cash Flow is \$2.6 billion
- Lost Royalties are \$820 million
- Lost Operating Costs in the Region (assuming these are flat at 85¢/mcf) remain at \$507 million
- Lost Capital Spending in the Region (at 20% of Field Cash Flow) is \$516 million
- Lost Operating Costs and Capital Spending in the Region are a **direct loss of economic activity in the affected area totaling \$1.02 billion**
- Lost Corporate Income Taxes (also at 20% of Field Cash Flow) are \$516 million.

These are huge losses to all stakeholders.

**Scenario 4** shows the “medium” price outlook, with prices at \$6.39 for 2004 then flat at \$5.65 each year through 2018. It also assumes the **ID 99-1** rules allow capital spending to proceed resulting in just a 6% annual production decline. Larger volumes mean all economic losses are higher. This is the most important of these scenarios because it demonstrates the change from the constraints of **ID 99-1** to the shut in of the entire region. It is our best estimate of the direct economic impact of the proposed **GB 2003-16**.

- Cumulative Lost Revenue is \$4.8 billion
- Lost Field Cash Flow is \$3.1 billion
- Lost Royalties are \$1.0 billion
- Lost Operating Costs in the Region (still assuming these are flat at 85¢/mcf) are \$706 million
- Lost Capital Spending in the Region (at 20% of Field Cash Flow) is \$621 million
- Lost Operating Costs and Capital Spending in the Region are a **direct loss of economic activity in the affected area totaling more than \$1.33 billion**
- Lost Corporate Income Taxes (also at 20% of Field Cash Flow) are \$621 million.

The key assumption in these four scenarios are that operating costs remain flat at 85¢/mcf. As produced volumes decline, unit costs would increase.

Four parallel scenarios that incorporate rising operating costs are modeled in **Scenarios 5 through 8**. Under either the blow-down cases or the modest development allowed by **ID 99-1** rules, declining production volumes would necessarily lead to higher operating costs. These scenarios also demonstrate the likely result of a partial or staged shut in of gas production.

**In all these cases, revenue and therefore royalties are not directly affected.**

Operating costs rise and as a result, field cash flows decline along with field capital spending and corporate income taxes (both assumed to be at 20% of cash flow). In fact, later in the period, production becomes uneconomic so that revenue and royalties eventually collapse. So do all the other economic measures.

**Scenario 5** shows the same low price schedule as **Scenario 1**. Operating costs rise from 80¢ for 2003 to \$3.30 for 2018.

- Lost Field Cash Flow is lower at \$1.6 billion vs \$2.0 billion
- Lost Operating Costs are higher at \$982 million vs \$507 million
- Lost Capital Spending in the Region is lower at \$311 million vs \$406 million
- Lost Operating Costs and Capital Spending in the Region are a **direct loss of economic activity in the affected area of nearly \$1.3 billion**
- Lost Corporate Income Taxes are also lower at the same \$311 million vs \$406 million.

But importantly, by 2008, cash flow is less than 50% of revenue. By 2013 it falls to 34% of revenue and by 2018 it is just 21% of revenue. This sharp fall in cash flow as a share of revenue means the operations are becoming uneconomic. So far I have not included general and administrative expenses or depreciation and depletion charges. If these expenses are included, even at conservative amounts, our data shows the region is just nominally profitable in 2014-2015 and runs at losses for 2016-2018.

As a result, sometime after 2013 (and likely even sooner) the entire region becomes borderline profitable. Falling production would lead to the rationalization of facilities. There would an immediate start to the destruction of economic value for wells, fields,

gathering facilities and gas-processing plants of the area. The economy and communities of the region would immediately begin a long-term decline.

In **Scenario 6** (“medium” prices) and **Scenario 7** (“high” prices), these operating cost increases are partly offset by higher prices. The collapse in profitability is not quite as swift; however, even under the high price forecast, production is barely profitable during 2016 to 2018. These results are shown in the tables (after page 18).

**Scenario 8** shows the results of continued development under the **ID 99-1** rules (and assuming “medium” prices as in **Scenario 4**). Production declines more slowly but operating costs per mcf rise each year. As in **Scenario 4**, total revenue and royalties are not directly affected, but eventually, the production economics collapses, along with all other measures.

- Lost Field Cash Flow is lower at \$2.3 billion vs \$3.1 billion at flat operating costs.
- Lost Operating Costs in the Region are higher at \$1.5 billion vs \$706 million at flat 85¢/mcf
- Lost Capital Spending in the Region (at 20% of Field Cash Flow) is \$459 million vs \$621 million
- Lost Operating Costs and Capital Spending in the Region are a **direct loss of economic activity in the affected area of nearly \$2.0 billion**
- Lost Corporate Income Taxes (also at 20% of Field Cash Flow) are \$459 million vs \$621 million.

Under this last scenario, operations also become marginal after 2014, and are nominally profitable for 2016 and 2017, before falling into a loss position for 2018. **It remains questionable whether 20% of this reduced level of field cash flow would be sufficient to sustain production on a 6% annual decline or whether the decline would be more serious. If cash flow were not sufficient to maintain a 6% annual decline rate, the economics would turn negative even sooner.** We regard this outcome as very likely.

Under these escalating operating cost scenarios, the apparent short-term “gains in economic benefits” to the region from higher operating costs drive the business past the brink of profitability. The gradual decline, typical of naturally declining resource extraction, starts at an accelerated rate of fall-off then suddenly goes into a free-fall. **The outcome of the imposition of policy restraints, rather than market forces on capital spending, is short-term hope then a swift collapse.**

These scenarios are important because they demonstrate the effects of the Board’s choices. If gas production in the entire Wabiskaw-McMurray Region is shut in, the direct economic costs are obvious and large. However, if the Board chooses to shut in some significant share of gas production, it quickly produces an economically unnatural imbalance between production volumes and the capital asset-base. This will, in our opinion, lead to a similar end: rationalization of infrastructure, closing of many plants, escalating operating costs, constrained cash flow, little business incentive for ongoing

capital spending and the early loss of profitability, even in the parts of the region left in production.

Once the region is redlined, the social impacts are perversely negative. Any likely Board decision (given its focus on the long-term value of bitumen reserves) will probably make it clear to the region's citizens that the future they had expected is dead. Many of those whose livelihood depends on servicing the gas industry will react by starting to look elsewhere for their future. These social impacts will be deep and long lasting.

## **Socio-Economic Impacts of the End of Gas Production**

The immediate shut-in of 215-250 mmcf/day of production in the Wabiskaw-McMurray region will have a devastating affect on the businesses, people, regional governments and communities in the area. A rolling-closure would have the same effect by allowing sharply limited future development.

### **1. The Loss of a Keystone Industry in a Remote Region (pages 7-8 and 16)**

When a key industry, providing long-term employment, is removed from any economic region, it initiates a downward spiral in the economy, with collateral damage seen in many forms. Over the past 20 years, natural gas has been a growth industry in the area, providing well paying jobs and the promise of long-term employment. An entire generation of citizens has built their futures and their communities on the basis that this industry would continue for another generation.

We have already seen examples of the socio-economic damage that occurs when a keystone industry dies or is killed by government action: the closing of coal mines in B.C and Alberta, the decline of the western wheat economy in the face of U.S. and European farm subsidies, the closing of the Newfoundland cod fishery (softened by billions in adjustment payments by Ottawa), the restrictions on the B.C. forest and mining industries and so forth.

We estimate that as many as 150 direct industry jobs will be wiped out. We further estimate that the indirect job losses may be as high as 225 to 300, using a multiplier effect of 1.5 to 2.0. While economists estimate the "economic multiplier" for Alberta at about 1.2 times, economists also agree that the size of the economic multiplier is much higher in poorer regions or countries that typically have limited economic choices available. We believe a higher multiplier is appropriate for any remote, resource-based region. Economic multipliers work in both directions: new capital spending and the withdrawal of existing capital spending.

If we simply count the dollars involved, the withdrawal of something above \$1 billion of spending in the affected region over 15 years, might suggest the loss of at least 700 jobs (\$67 million per year for 15 years at \$100,000 per job). Since the largest impacts are early

in the period and most jobs do not pay \$100,000, the lost employment may be much higher.

## **2. Local Municipal Taxes Will Decline** (pages 14-16)

We estimate that the total loss in municipal taxes for the MD of Opportunity may exceed \$400,000 from all producers. This would be nearly 2% of Opportunity's estimated \$22.6 million annual budget and just over 2.2% of its \$18.3 million of **local tax revenue** when we exclude the provincial transfer payments for specific obligations. The hamlets of Wabasca, Red Earth Creek and Calling Lake are all heavily dependent on the gas industry. Service companies and other retail operations in these communities will be severely impacted. This will likely lead to other losses in the tax base, as companies close and move away.

We estimate the total loss in municipal taxes for Lakeland County may exceed \$500,000 from all producers. This would also be about 2% of Lakeland's \$23.7 million budget. We should also expect an economic impact that reduces other economic activities, including a wide range of business closings. Lac La Biche is the government centre for Lakeland County, but also depends on gas activities in the area. Other communities in Lakeland are more dependent on the natural gas industry. However, in both jurisdictions, business tax revenue would likely fall from the service companies that depend on the gas industry and from other businesses that serve the general population.

Over the 15-year period, the tax losses for Opportunity and Lakeland (at least \$400,000 plus \$500,000) could add up to some \$15 million. The tax shortfall would have to be covered by either higher taxes on other businesses, as part of the long-term problem causing regional economic decline, or higher residential property taxes.

In the MD of Opportunity, residential and farmland taxes account for just \$199,364 of property taxes, while business taxes (non-residential and machinery and equipment taxes) account for \$17,942,204 or 98.9% of the total! A significant loss and continuing decline in the business tax base suggests that residential taxes could be forced to increase by factors of 100%, 200%, 300% or more. For example, a 5% loss in the non-residential plus machinery and equipment taxes in the MD of Opportunity would amount to \$897,110 or 450% of the total taxes on residential and farmland properties.

The MD of Wood Buffalo is dominated by the oil sands, so Fort McMurray is not as dependent on municipal taxes from gas producers. Wood Buffalo's tax base is not seriously threatened, but businesses in smaller communities, more dependent on natural gas operations, will be affected.

## **3. Social Outcomes of this Economic Collapse** (page 16)

The social outcomes are predictable. The lack of a stable future makes it very difficult for families to plan a life in a declining community. More young people move away, there are fewer young children so schools are under-utilized, and eventually, fewer teachers are required. The downward cycle is cumulative.

The losses spread to all businesses in the small communities: variety and grocery stores, barbershops, taverns, gasoline stations, drug stores and all basic retail operations relying on the incomes of the local residents. There are also strains on families. It is to be expected that alcoholism and family violence will increase among those who remain behind because of their reduced incomes and opportunities.

The average age of the population will increase, creating higher demands for social services, supported by a declining tax base. As people leave, property values fall; thus, eroding the small residential tax base. The demands for social assistance will rise and the residential tax rate may be forced to increase even higher.

In this battle between natural gas now and bitumen production later, the people who live in smaller communities throughout the Wabiskaw-McMurray region are likely to be the major casualties. It is also worth noting that the oil sands currently pay royalties of less than 1% of total revenue, compared to 20% or more for natural gas producers.

**These are but a few of the most obvious and predictable outcomes based on the experience in other regions of Canada. The social costs of a downward economic cycle are very high.** We expect that the long-term impact will replay the examples cited for other smaller remote resource-dependent communities that lose a significant source of employment. Unhappily, the MD of Opportunity may have to amend its motto from “The Land of Opportunity”.

#### **4. A Terrible Time to Shut Down Gas production**

We get a sense of the magnitude of the immediate impact of the loss of 250 mmcf/day effective August 1, 2003, by comparing that to the five-year average volumes of gas injected during August, September and October. The complete shut in of gas production from the Wabiskaw-McMurray region would amount to 21.55% of the volume of gas injected into Canadian storage facilities and to 3.05% of all gas injected into the much larger U.S. storage system. (See the last six tables after page 18 in the Report). Current summer prices in Canada and the U.S. are the highest in history. **This is a decidedly bad time for Alberta to lose some 2% of its gas production.**

U.S. drilling is still below the levels required to meet demand. This is partly the result of the 2000-2001 price spike followed by the 2001-2002 price collapse. I believe this extreme volatility was primarily the result of the California energy crisis, not weather and real supply shortages. But the excessive drilling and production response flooded a market that was shedding demand in the face of artificially high prices. Through 2002, prices were terrible and the gas industry has not yet recovered its confidence in the price outlook. For that reason, new supply has been slow to appear and initial decline rates are running at historic high levels.

U.S. gas storage is currently about 600 bcf below the record high levels of last year (the cause of last summer’s very painful low prices) and about 300 bcf below the 3-year and 5-year averages. We know first half consumption this year was above last year (largely due

to requirements for space heating during the long, cold winter into April), and the best estimates are that the U.S. will only reach the “normal” 3-Tcf-full level by the start of November if there is a significant shedding of demand from the industrial sector (petrochemicals and fertilizer). We also know that more combined-cycle natural gas power stations have come online over the past three years.

We cannot estimate a price-impact of the proposed shut in of gas, but over the July-August period, the weather will be the determining factor on price. Hot weather creates electricity demand for air conditioning, so storage injections slow, creating fear in the market over possible shortages in next winter’s heating season. We can confidently suggest that “all other things being equal”, the immediate loss of up to 250 mmcf/day of Canadian gas will cause prices to be higher than if the shut in did not take place.

For a longer-term view, we should note the U.S. gas industry has been producing about 19 trillion cubic feet (Tcf) per year since 1996. The only exception was 2001, when extremely high prices resulted in a surge of gas-well completions and a pulse in production. For 2002, and likely for 2003, gas production will be back at or below 19 Tcf. U.S. consumption of gas has grown from 17.2 Tcf in 1987 to 22.5 Tcf for 2000, but fallen to an estimated 20.4 Tcf for 2002. The shortfall of U.S. domestic production has been met by a spectacular increase in imports from Canada; from under 800 bcf in 1986 to about 3.9 Tcf for 2001 and 2002.

If it were not for this import of Canadian gas over the past 15 years, U.S. prices would have settled long ago at much higher levels. We can all recall repeated claims of “dumping” from some unhappy American producers. If Canada cannot continue to register annual increases in export volumes to the U.S., sustained prices at these higher levels may well be the story of the future. Prices at the US \$4.00 to \$4.50 will, in time, generate additional gas drilling in both countries. **The stark reality is that both countries will have to drill record numbers of gas wells forever, in order to meet the current and growing demand for natural gas.**

If higher prices are likely (as in our two “high” price scenarios), then the shut in gas will have a much higher value and the economics of gas-fuelled oil sands extraction has a somewhat dimmer future. Coupled with the issue of the demand for water for oil sands projects, the Board has a lot to weigh in this current clash between gas production and the conservation of bitumen reserves in the Wabiskaw-McMurray region.

Thank you for your time.

# **NE Alberta Gas - Bitumen: Economic, Social Impacts**

**John Shiry**

*President*

**Woodside Research Ltd.**

for

**Alberta Energy & Utilities Board**

**Re: GB 2003-16**

July 3, 2003

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## Assumptions:

- Lost Initial Production: 230 mmcf/d
- Blow-down vs Maintenance Drilling (ID 99-1 Rules: 6% Annual Decline)
- Prices at McDaniel vs “Medium” at \$5.65 Flat, “High” at \$6.40 Flat
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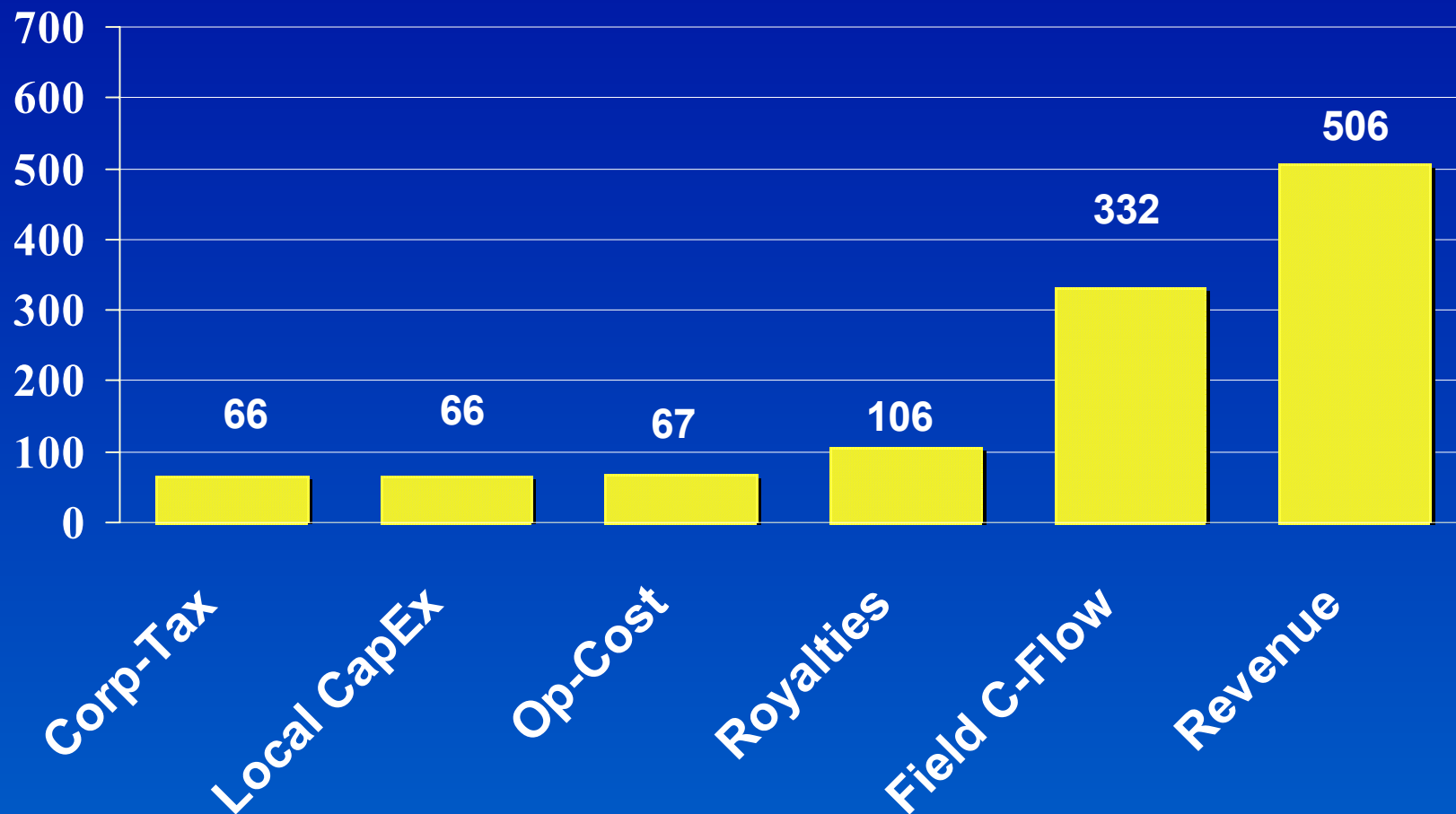
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**Scenario 4: Medium Price-\$5.65, ID 99-1, OpCost--**

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- **But the “Profitability-Wall” After 2014**

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# **Impacts of GB 2003-16**

**Scenario 8: Medium Price-\$5.65, ID 99-1,OpCost++**

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- **Lost Operating Costs: \$1.5 Billion**
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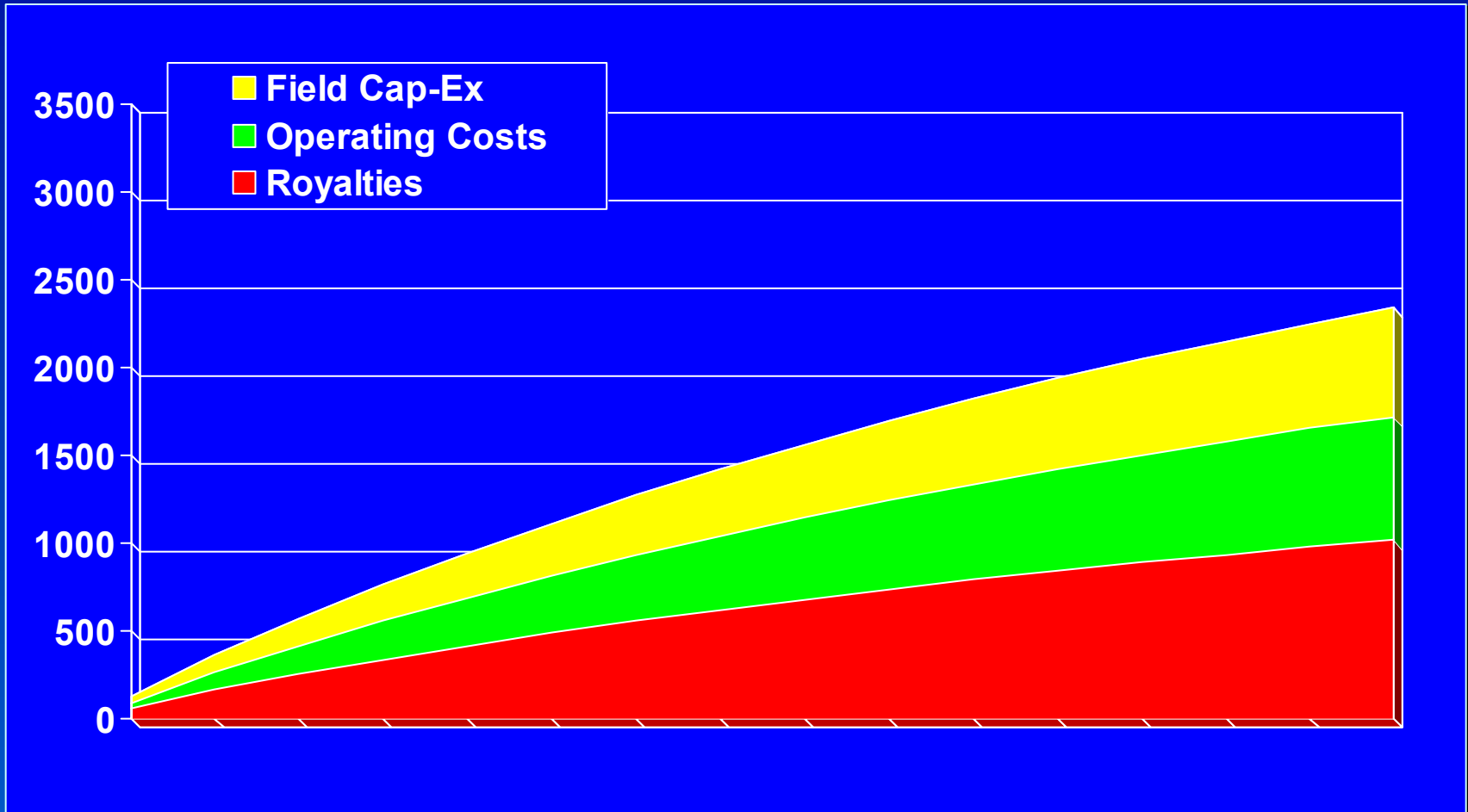
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4	\$5.65/ mcf	6% / Year	Flat	4,800	706	1,013	3,104	621	621
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# Lost Royalty, Op.Cost, Cap-Ex

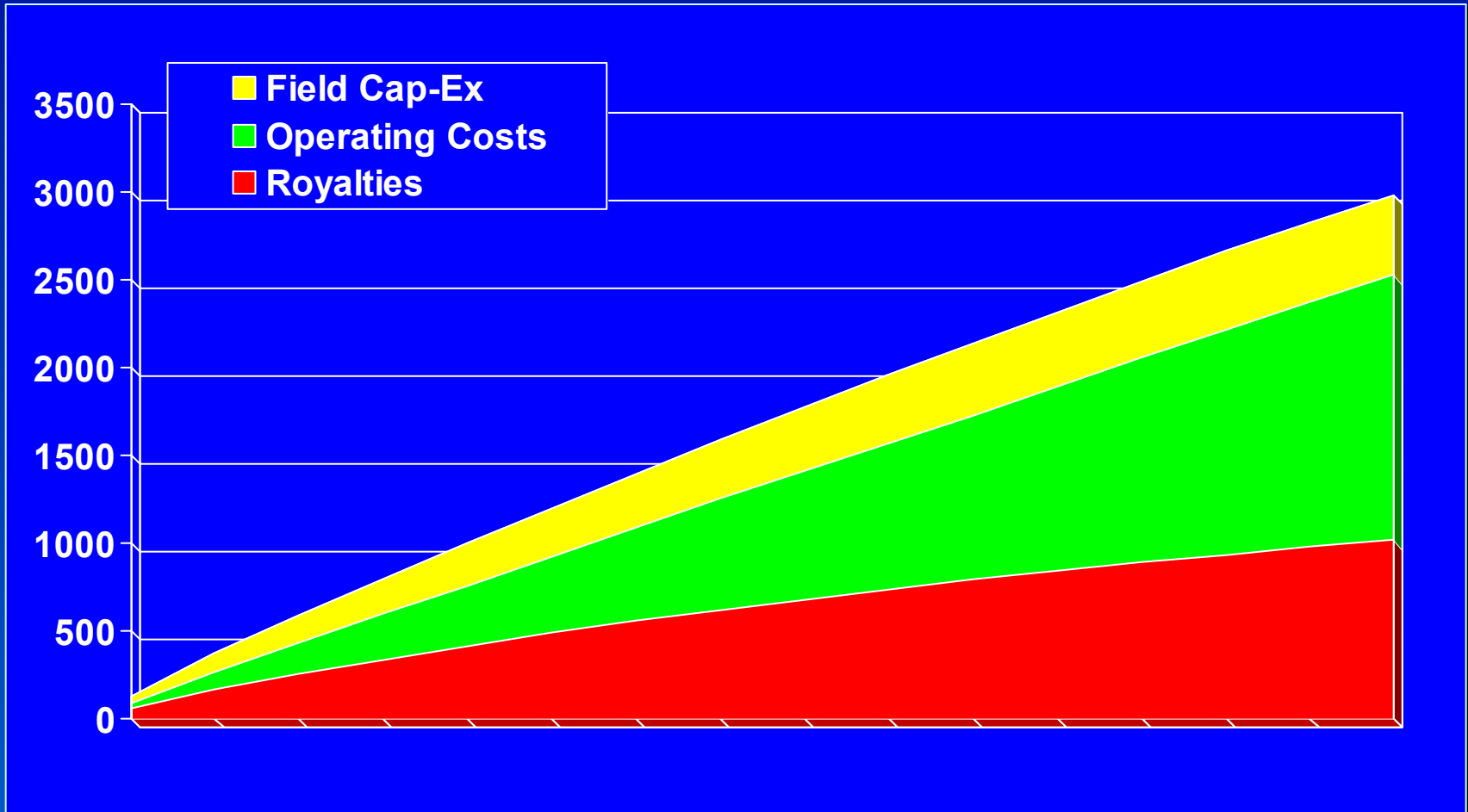
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# Lost Royalty, Op.Cost, Cap-Ex

Scenario 8: Rising OpCosts, "Medium" Prices, ID 99-1  
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## **Between a Rock and...**

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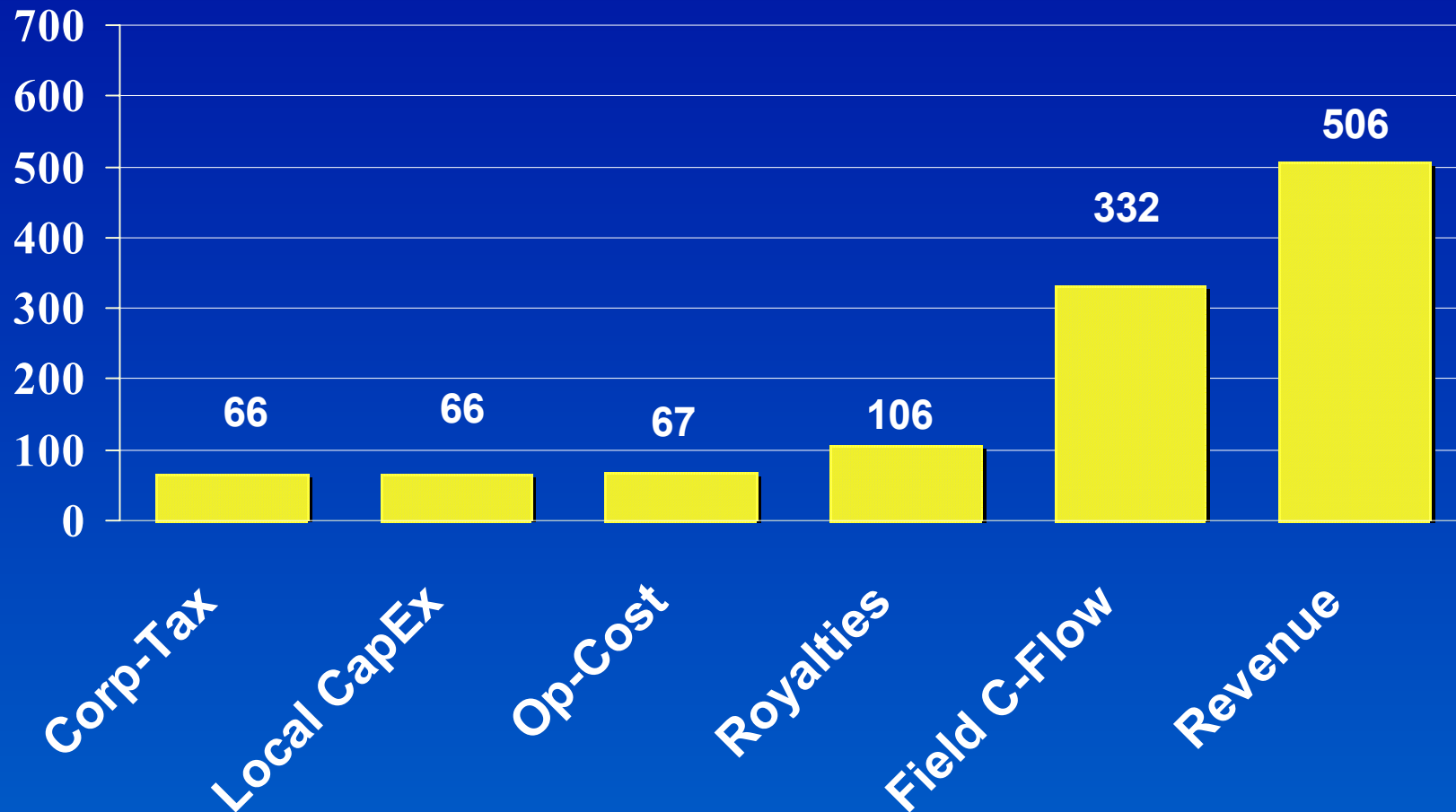
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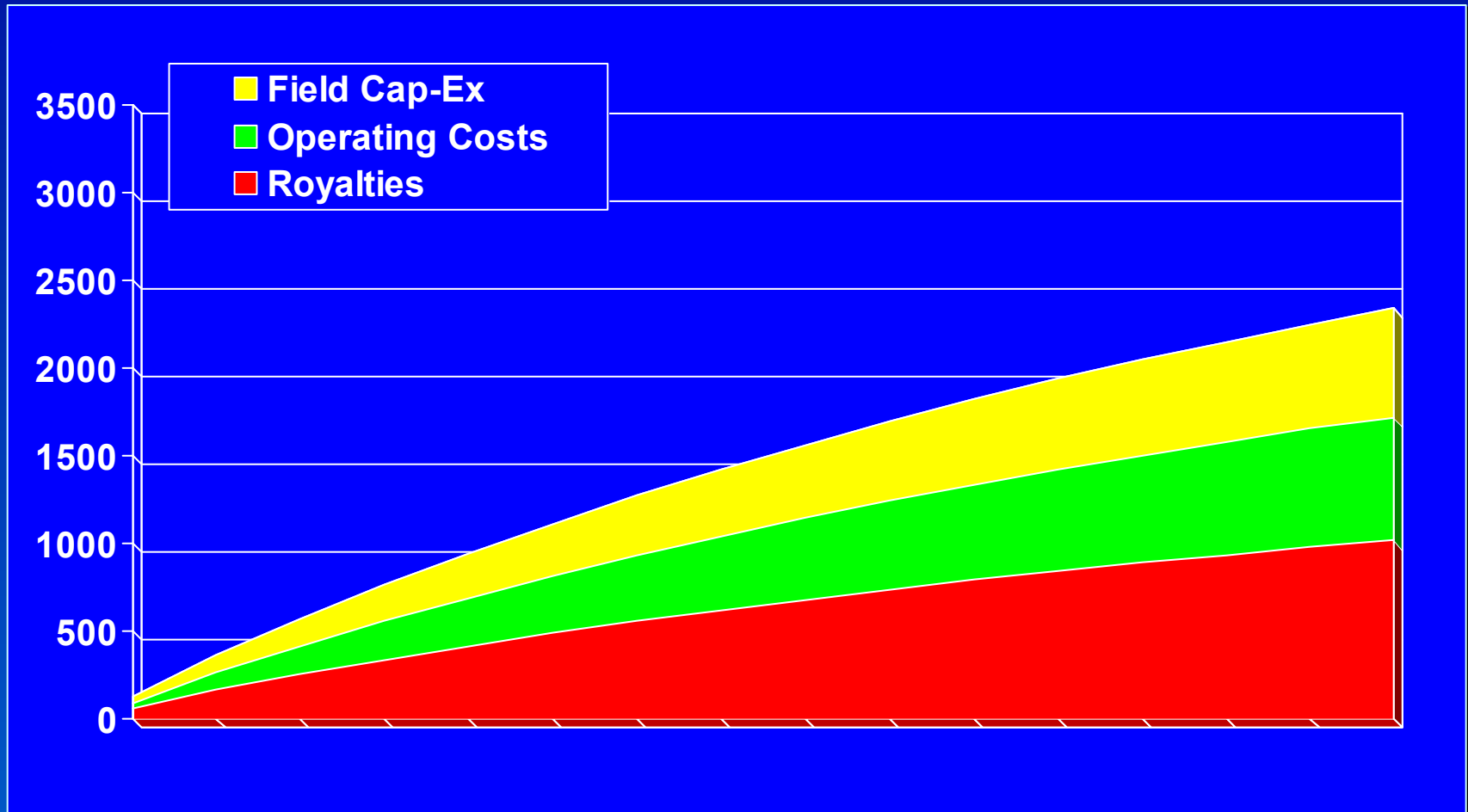
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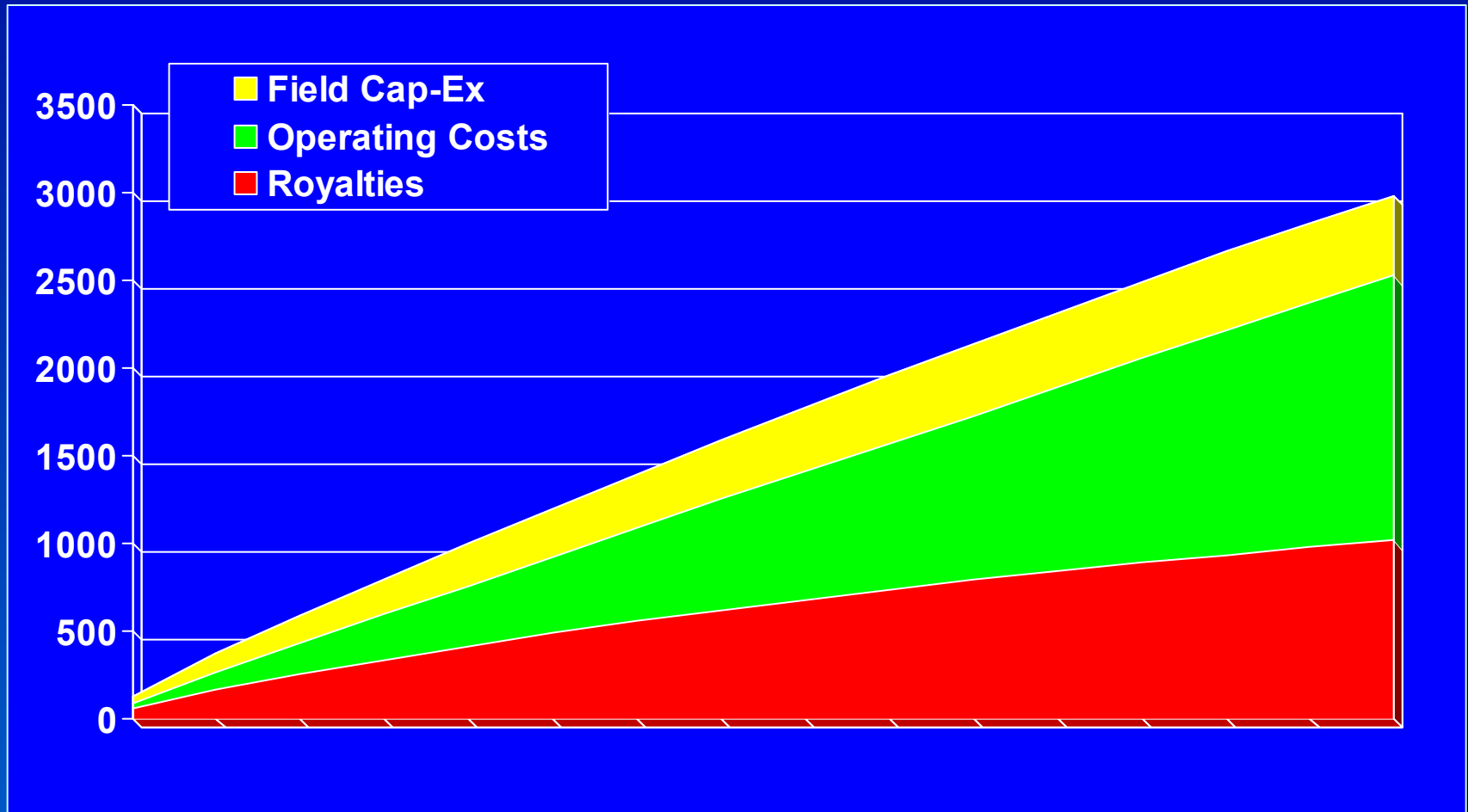
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# **Bad Time to Shut In Gas**

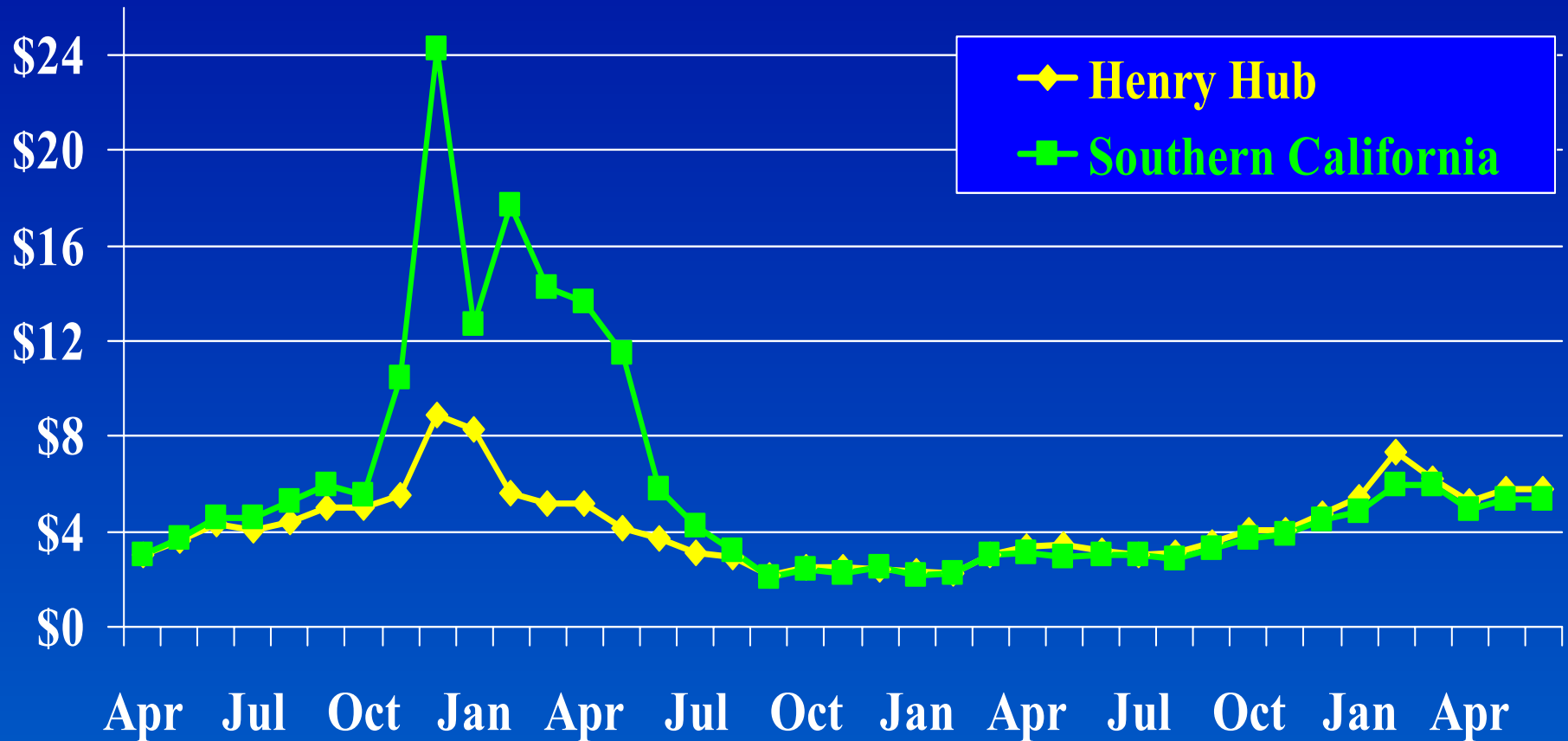
## **Continental Gas Market Fundamentals**

- **Last Price Spike was Not Natural: Low Prices of 2002 Spooked the Industry**
- **U.S. Production Flat Since 1996**
- **Canadian Production Down in 2003**
- **Canadian Exports Fell Last Year**
- **U.S. Demand Recovering, Supply Not**
- **Storage at Very Low Levels**
- **Record High Summer Prices Mean “Gas Supply Crisis” is Real**

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# U.S. Spot Gas Prices

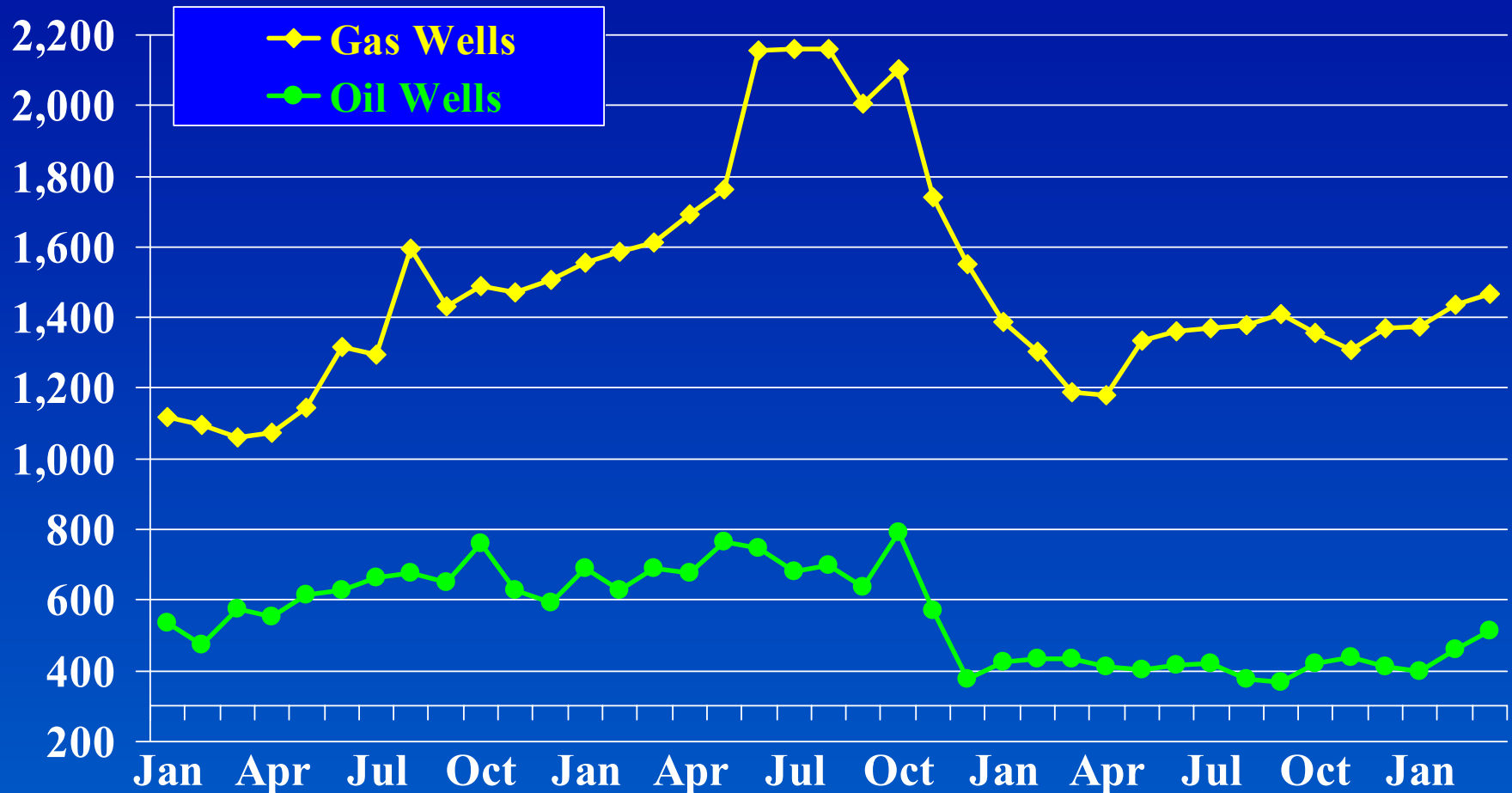
(Apr '00-Jun '03: monthly average – US\$/mmbtu)



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# U.S. Oil & Gas Drilling

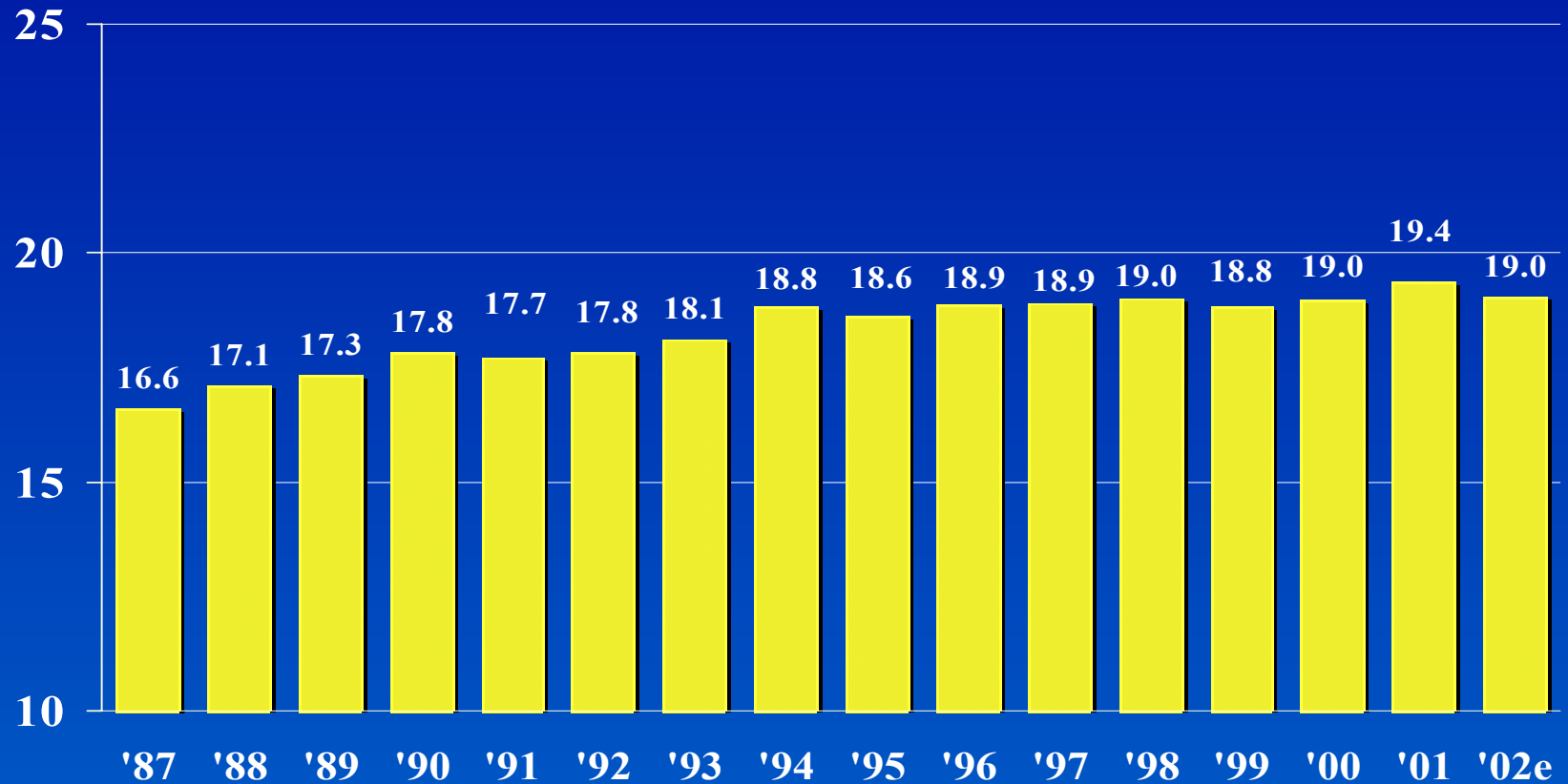
(2000-2002 monthly total completions: EIA)



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# U.S. Natural Gas Production

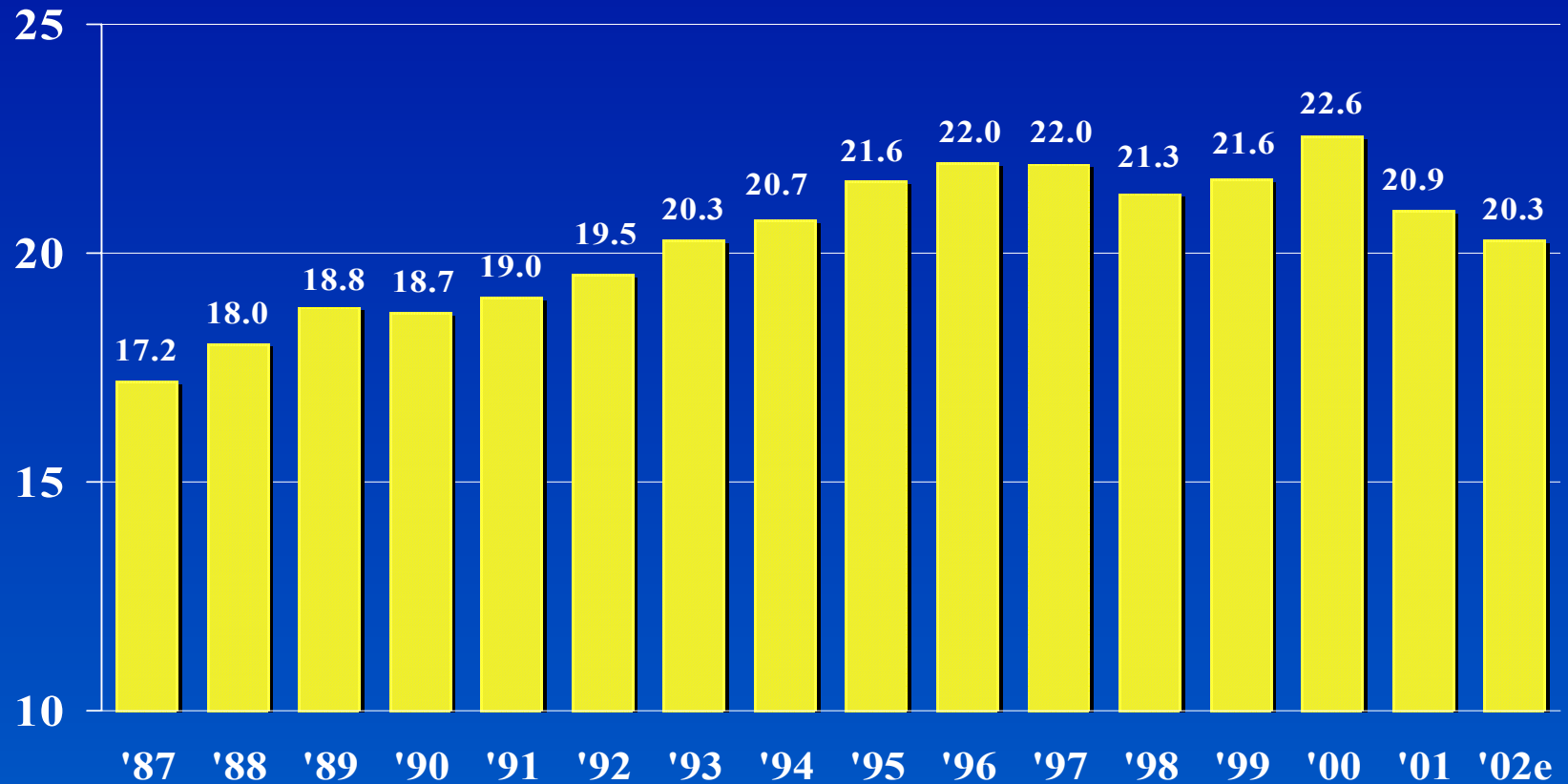
(tcf/year: EIA)



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# U.S. Natural Gas Demand

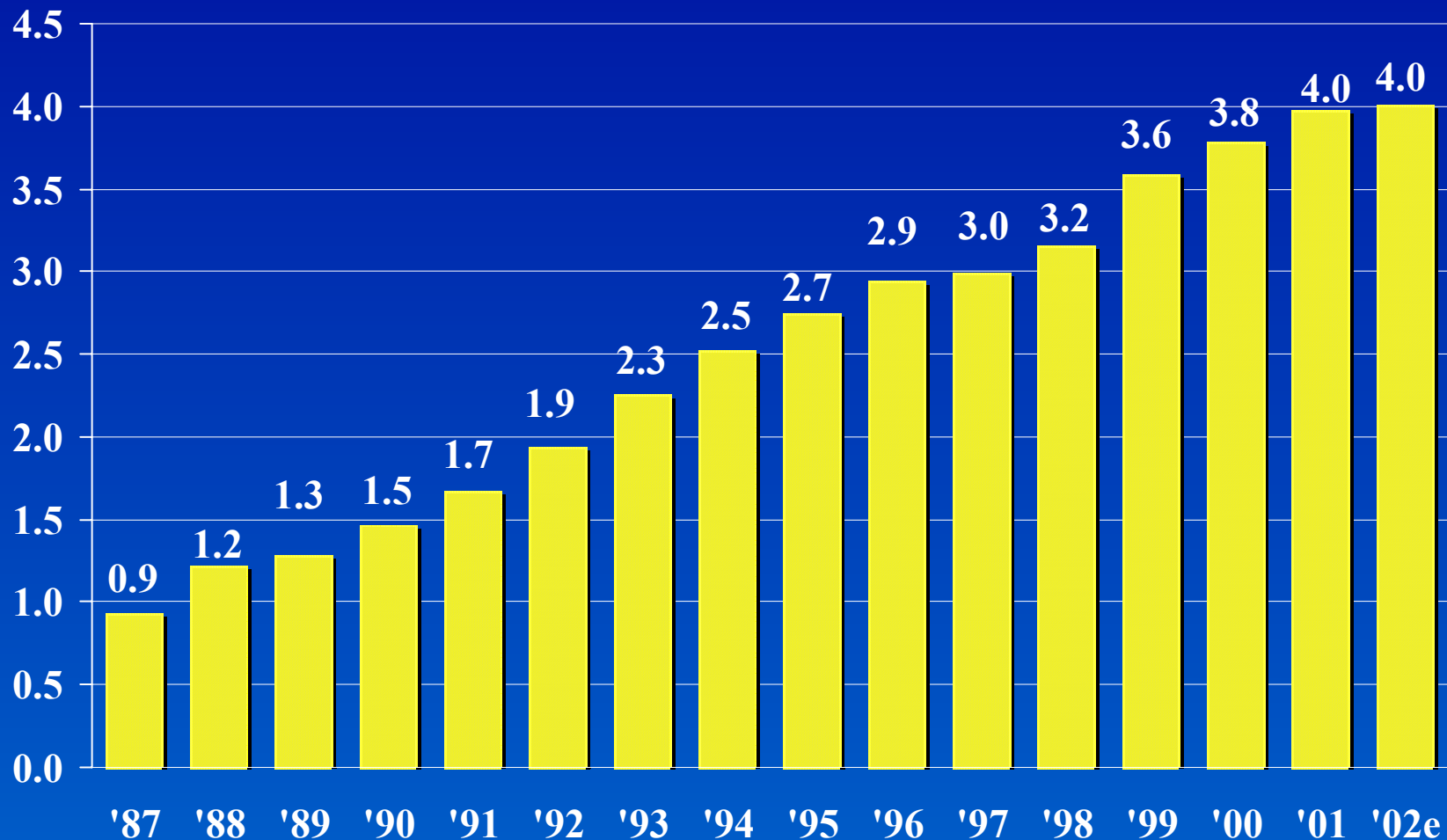
(tcf/year: EIA)



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# U.S. Natural Gas Imports

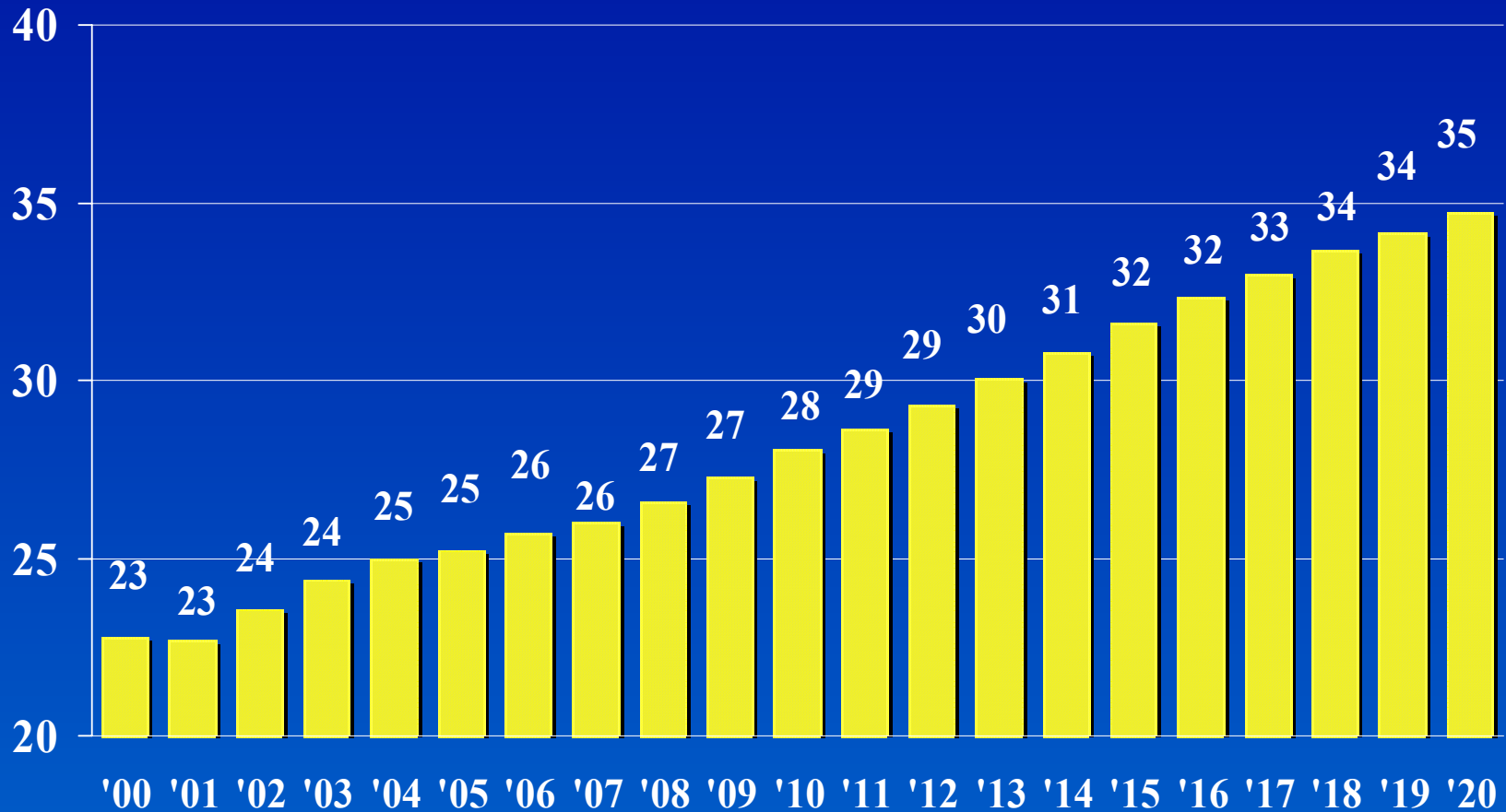
(tcf/year: EIA)



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# U.S. Forecast Gas Use

(lower 48 states – tcf/year: EIA 1999)



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