



REPORT TO THE ALASKA LEGISLATURE ON PRODUCTION COST INCREASES

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Report to the Alaska Legislature on Production Cost Increases

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I. Introduction

This report addresses issues raised in Senator Therriault's August 30, 2007 letter on PPT lease costs. In preparing this report we have,

- reviewed the modeling used for the Alaska Department of Revenue's (DOR) Fiscal Note accompanying HB 3001;
- reviewed DOR's August 3, 2007 PPT Status Report;
- interviewed DOR personnel familiar with the DOR models, cost assumptions and PPT filings by the producers;
- reviewed various presentations made during PPT hearings last year;
- reviewed SEC filings made by producers;
- reviewed data compiled by the Energy Information Agency regarding production costs;
- reviewed reports prepared by market analysts regarding production costs; and
- reviewed cost information regarding drilling rig rates in the Lower 48 states.

II. DOR Forecast Lease Cost Increases Generally

The Alaska Department of Revenue (DOR) issued a "PPT Status Report" on August 3, 2007. In that report, the DOR stated that for FY 2008, revenues were expected to be \$800 million lower than earlier forecasts, as reflected in the Fiscal Note accompanying HB 3001. The DOR Status Report is included here as Attachment 1.

The DOR identified higher than forecast costs as the primary reason for the decrease in projected revenues. Relative to the HB 3001 Fiscal Note, the DOR forecast lease cost increases for FY 2008 of nearly \$2 billion. This represents an approximate 100% increase in costs. Capital cost forecasts increased by \$1.1 billion, while operating costs increased by \$0.9 billion. The impact of increased costs forecasts would account for the reduction in forecast revenues of approximately \$800 million as set forth in the Status Report.

In the Fiscal Note accompanying HB 2001 (ACES), the DOR has increased its cost increases further. The DOR currently projects total operating and capital costs for FY 2008 of \$4.33 billion, an increase of approximately 7% over the figures set forth in the August 2007 Status Report. DOR expects these higher cost levels to continue for the

near future. Attachment 2 sets forth the DOR's current lease cost forecasts through Fiscal 2014.

III. Basis for the Costs Used in DOR's HB 3001 Fiscal Note

The cost projections included in DOR's HB 3001 Fiscal Note were developed in late 2005 and were based on information available at that time. This included confidential income tax returns and public SEC filings for the years through 2004 -- the most recent years available in 2005 -- and published consultant reports covering the period through 2003. DOR reviewed this information with the producers. In addition, we (Econ One) reviewed the DOR's cost projections.

The cost projections used in DOR's HB 3001 Fiscal Note totaled approximately \$2.1 billion for the FY 2008. On a (gross) per-barrel basis, those cost projections averaged \$7.27/bbl.¹ DOR's current volume projections for FY 2008 are approximately 79,000 (79 mbd) lower (725 mbd vs 804 mbd) than they were at the time the Fiscal Note was prepared. Holding total costs constant, this projected drop in volumes would increase the average cost to \$8.04/bbl, an increase of just over 10%.²

The DOR cost projections were used throughout the PPT debate in the spring and summer of 2006 in the analyses it presented to the legislature. In addition, industry presented revenue estimates during the debate that incorporated cost projections in line with the DOR projections.³

We also prepared various revenue projections during the PPT hearings. Those projections fell into two categories: (1) the economics of exploration and development and (2) revenues arising from production in fields included in production forecasts used in DOR's Fiscal Note. Our base cost estimates used in these later estimates were somewhat, though not significantly, higher than the cost estimates used by the DOR.⁴

IV. The Basis for DOR's Current Cost Forecasts

DOR has based its current cost forecasts primarily on the filings submitted by the producer/taxpayers. As has been stated by DOR personnel in testimony, these costs are

¹ The \$7.27/bbl figure represents the average cost per barrel produced. Spread across taxable barrels (assuming an average royalty of approximately 12.9%), it would be \$8.35/bbl.

² The increase in average \$/bbl costs resulting from volume declines may be somewhat smaller than noted above, as a small portion of the total operating costs would be variable with production.

³ See ConocoPhillips presentation on February 27, 2006. While the cost assumptions are not stated in the chart, the revenues for the PPT are in line with the DOR projections, indicating that similar costs were used in the analysis.

⁴ In addition, we presented revenue sensitivities showing varying cost increases over base forecasts. These included a 20% cost increase, an assumption of a tripling of cost inflation (i.e., 7.5% rather than 2.5%) and an increase in capital expenditures by approximately 100% to an annual rate of \$2.5 billion.

not audited, nor have they been adjusted by DOR for potential misstatements or reporting errors.

To our knowledge, DOR has not reviewed any of the supporting information behind the tax filings. Moreover, DOR has not reviewed any of the other information that would regularly be prepared by the field operators detailing their actual and anticipated costs. These would include items such as annual operating budgets, production and drilling plans, regular (e.g., quarterly and annual) expense statements and capital expenditure authorizations (AFEs). This is information that would be shared regularly between working interest owners in each unit.⁵

Without a review of the information underlying the tax filings, or a review of the types of budget and expense reports prepared by the operator of each unit, it is not possible at this time to determine whether the cost increases (relative to the earlier Fiscal Note assumptions) that are reflected in the tax filings to date and the DOR's current cost forecasts will prove to be accurate, or whether they may be adjusted after review.

V. Rising Costs Over the Past Several Years

There is broad consensus among industry analysts that per-barrel operating and capital costs in the U.S. have increased sharply over the past several years. The increase in costs has been higher than general inflation and is driven in large part by higher sustained oil and gas prices relative to expectations of several years ago.

Attachment 3 shows actual ANS West Coast prices over the period January 2000 through September 2007. During this period, ANS prices have increased by approximately \$50/bbl. Moreover, expectations as to long-term crude oil prices have increased considerably just since January 2005. Attachment 4 shows expected price levels as reflected in NYMEX futures trading for oil delivered at the end of 2011. In January 2005 the forward price on the NYMEX was close to \$40/bbl. The forward price rose sharply over the course of the year, ending at close to \$60/bbl. Today, the forward price for delivery at the end of 2011 is about \$80/bbl, which is an increase of \$40/bbl since January 2005.

Expectations for sharply increased, long-term crude oil prices have led companies to spend more money looking for and evaluating prospective properties. In addition, it has led them to spend more money developing costlier reserves from existing properties. This additional demand, which results in large part from an increase in price expectations, has led to increased costs.

VI. Publicly Available Data Regarding Production Cost Increases

Publicly available data reflecting operating and capital costs show increases generally over the past several years, with sharp increases occurring in 2005 and 2006. The timing

⁵ It is our understanding that DOR does not have access to this information at this time.

of these increases is consistent with rapid increases in actual and expected long-term crude oil prices that began in 2005.

Attachment 5 shows an index of upstream capital costs since 2000 presented in a May 8, 2007 release by the consulting firm IHS/CERA. The index is designed to track capital costs associated with oil and gas production world-wide. The IHS/CERA figures show moderate cost inflation (consistent with the general economy) through 2004, then rising quickly, particularly in the 2nd half of 2005 and throughout 2006.

Attachment 6 shows an index of operating costs prepared from lease cost data reported by the Energy Information Administration (EIA) for Lower 48 states.⁶ The EIA operating data shows a cumulative cost increase of 29% in 2006 relative to average cost levels over the 2002 - 2004 period that formed the basis of the earlier DOR forecast.

Attachment 7 shows an index of equipment costs prepared from the same EIA data. This chart shows a relative large increase in costs occurring in 2004, moderating somewhat in 2005 and 2006. On average, 2006 equipment costs reflected in the EIA data were 32% greater than average costs over the 2002 - 2004 period.

Attachment 8 shows an index of daily rental rates for oil drilling rigs in the Lower 48 states prepared using data from the Land Rig Newsletter. Rental rates for oil drilling rigs in the Lower 48 began rising in 2004 and increased sharply in 2005. The rate of increase slowed somewhat in 2006 and has actually declined since 1Q2006. Overall, the index shows an approximate doubling of 2006 daily rig rental rates relative to the 2002 - 2004 period.

None of the data presented in these attachments reflect actual costs in Alaska. Rather, they reflect generalized world-wide costs or costs in the Lower-48 states. These data indicate that the cost of production has risen generally over the course of the past several years. We would expect that the same pressures on production costs outside of Alaska would lead to increased costs in Alaska. And given some of the unique aspects of Alaska's production (isolation, shorter drilling season, number of suppliers available to industry in Alaska during the short-term), combined with the impact of the corrosion repair and "integrity management" work in Alaska, these general cost pressures may impact the State greater than they have elsewhere, at least in the near term.

VII. Production Costs Reported to the SEC and Alaska Specific Costs

Publicly traded oil companies report production costs to the SEC in their annual filings. US companies' data is contained in their form 10-K. Foreign companies, such as BP, report the information in form 20-F. In some cases the costs are broken out separately for Alaska and other areas. Attachments 9 - 12 set forth reported production costs per barrel for ConocoPhillips, BP, ExxonMobil and Chevron. The reported production costs reflect operating expenses and do not include capital investments.

⁶ The EIA does not publish data for Alaska.

ConocoPhillips and BP report their production costs in Alaska separately from production costs elsewhere. These reported figures show generally increasing production costs worldwide over the past 4 years, with higher increases in the U.S. and in Alaska in particular. Alaska cost increases reported by BP were much greater than those reported by ConocoPhillips over the last 2 years.

ConocoPhillips' publicly reported production costs over the period 2003 - 2006 for equity production in Alaska and the Lower 48 states are set forth in Attachment 9. The ConocoPhillips' data shows Alaska production costs of approximately \$3.50 per barrel between 2003 and 2005. These are similar to the operating costs used by the DOR in their earlier forecasting.

Consistent with the cost and price data presented above, the ConocoPhillips' reported costs began to rise in 2005, with a sharp (63%) increase in 2006 to approximately \$6.40/bbl. ConocoPhillips' production costs for the Lower 48 states shows a much more moderate rate of increase over the past 4 years than do their Alaska costs.

BP's publicly reported production costs over the same period for equity production in Alaska, the United States and the rest of the world are set forth in Attachment 10. BP's reported figures for Alaska are in the same general range as ConocoPhillips' costs for 2003 and 2004 (approximately \$3.50 per barrel), then rise in 2005 by 38%, with a further sharp (81%) increase to over \$9.00/bbl in 2006.

ExxonMobil's reported costs are shown in Attachment 11. Unlike the other 2 large producers, ExxonMobil does not break out Alaska in its public filings. ExxonMobil's reported figures show increasing production costs over the 2002 - 2006 period higher worldwide, with a greater increase in the US, particularly in 2006.

Attachment 12 shows production costs reported by Chevron for the 2002 - 2006 period. Chevron's costs show increases generally over the period, with larger increases in the US beginning in 2005.

VIII. Information on Corrosion-Related Costs

DOR personnel stated that they did not know the amount that has been claimed for costs related to corrosion repair work on the North Slope. The level of cost reporting contained in the PPT filings does not provide detail regarding the nature of underlying costs. And as discussed above, these tax filings largely form the basis for DOR's cost projections going forward.

One way to attempt to determine the extent of corrosion related costs claimed and included in the tax filings would be to examine and compare the tax data across taxpayers and units, comparing costs claimed for Prudhoe Bay and by BP with costs claimed by other taxpayers and for other areas. While DOR has certainly done this, they stated that they could not share any data or analysis with us due to stated tax-payer confidentiality issues.

BP has stated publicly that it will spend \$260 million to replace the oil transit lines (OTLs) at Prudhoe Bay. Assuming these costs are all spent during 2006 and 2007, they would represent a little more than a \$1/bbl cost spread across taxable barrels at Prudhoe Bay for those two years.

In addition to the \$260 million OTL replacement cost figure, BP reported in its 2006 form 20-F that it planned to spend over \$550 million during 2007 and 2008 “net” on “integrity management” in Alaska.⁷

There are several questions with respect to this figure and how it relates to the corrosion issues. First, BP’s filings do not define what is included in “integrity management.” However, the statement would appear to be directed to efforts to insure the “integrity” of facilities at Alaska in an effort to prevent future spills or shutdowns. Second, BP’s reports do not specify whether these would be operating or capital expenses. Third, it is unclear whether the \$550 million figure is all that is anticipated with respect to the integrity management issues, or whether BP has just reported anticipated costs for a two-year period. Fourth, it is unclear whether the \$550 million refers to expenses born solely by BP in its capacity as working interest owner, or whether these reflect the gross amount that BP as operator will pay on behalf of itself and the other working interest owners at Prudhoe Bay. If these expenses reflect BP’s net working interest share, then the total integrity management expenditures over the 2007 – 2008 period could be far greater than \$550 million. Finally, aside from this statement, BP’s filings do not separately list expenditure amounts related to “integrity management” issues prior to 2007. Accordingly, the publicly available data do not allow us to determine exactly how much of the \$550 million spending represents an increase in spending levels for this expense category relative to prior years.

Whether and to what extent corrosion-related costs are reported as a part of taxpayers’ PPT deductions, the impact of these events likely has had some effect on increasing overall production costs on the North Slope for non-corrosion-related production services. As discussed above, increasing oil prices overall have put pressure on costs. The added pressure to deal with the corrosion repair and integrity management issues, particularly in a short time period, adds to the general cost pressure brought about by rising crude oil price expectations.

IX. Some Final Thoughts on Cost Increases and the PPT

⁷ BP’s 2006 form 20-F, page 19 states, “In response to the recent corrosion discoveries, BP has decided to replace the main oil transit lines (16 miles) in both the Eastern and Western Operating Areas of Prudhoe Bay. In addition, BP plans to spend over \$550 million (net) over the next two years on integrity management in Alaska.”

The PPT system, through the deduction of costs and capital credits, was designed to encourage capital investment and increased production in Alaska over the long run. Accordingly, the fact that costs have risen relative to expectations, particularly capital-related costs, should not be viewed in and of itself as a problem. Indeed, increased capital spending is one of the policy objectives of the PPT system.

However, it would seem doubtful that the entirety, or even the majority, of the cost increases reflected in the producers' tax filings to date relative to the projections used in the earlier Fiscal Note are the result of potential stimulative effects of the PPT system.

At the outset of this project we had sought to obtain data from the DOR as to costs filed by category (i.e., capital and operating) at different fields. Examination of that data might provide an indication as to where (geographically) the cost increases relative to forecast were coming from. In addition, such an examination, along with information regarding drilling activity, might provide insight into the question of whether some of the increased costs could be explained by increased exploration activity and/or development activity in certain areas, which are policy objectives of the tax system.

As discussed above, DOR personnel have maintained that cost information by taxpayer and even aggregated cost across taxpayers by field or unit, is considered as taxpayer confidential and could not be made available. Accordingly, we were not able to undertake this analysis as initially hoped.

Based on our discussions with DOR personnel and the data reviewed we can draw the following conclusions with respect to the cost increases in DOR's modeling at this time.

- The DOR's forecasts are based largely on unaudited taxpayer returns under the PPT tax. Those costs may be reduced after review and audit.
- An increase in costs for Alaska production is consistent with the cost patterns observed generally in the industry during the past several years. Costs began to increase sharply beginning generally in 2005.
- Forecast costs used in DOR's Fiscal Note to HB 3001 appear to be in line with publicly (SEC) reported information specific to Alaska during the period 2002 through 2005.
- Capital cost forecasts used by the DOR in the HB 3001 Fiscal Note are in line with historical capital spending levels on the North Slope between 2002 and 2005.
- Repair costs for corrosion related work and integrity management on the North Slope likely add costs for non-corrosion related costs in Alaska generally.

- The increases in costs filed with the SEC for Alaska relative to the Lower 48 and elsewhere reflect in part, expenses associated with corrosion repair and “integrity management” efforts in Alaska.
- The size of the cost increases, as reflected in the DOR’s forecasts, suggests that corrosion-related expenses and/or higher anticipated “integrity management” expenses are likely included in the tax filings, and as a result, included as a part of the cost forecasts.
- A proper determination of the reasons (appropriate or inappropriate) underlying the cost increases will require examination of the data underlying producer/taxpayer returns and claims under the PPT period. The examination should include review of unit-by-unit cost information both during the PPT period (i.e., from April 2006 forward) and during the several years prior to the implementation of the PPT.
- Costs have increased in recent years with unexpected increases in expectations of future crude oil prices. In the event that price expectations increase further costs may further increase. The level of increase is likely to be mitigated over the longer run with new entry (i.e., increased supply) for production-related services.
- Likewise, to the extent that long-run price expectations fall significantly (say down to \$40/bbl), we can expect to see downward pressure on costs over the long term.
- DOR did not include a cost/price sensitivity in its HP 3001 Fiscal Note or in its PPT Status Report. Its current forecast adjusts costs up or down when expected price levels rise above or fall below \$60/bbl, respectively. While these relationships are difficult to estimate with precision given the information available, in our view, this type of sensitivity is a good addition to the forecasting process.

Attachment 1

Petroleum Profits Tax (PPT)
Implementation Status Report

Alaska Department of Revenue
August 3, 2007

PPT IMPLEMENTATION STATUS REPORT

I. Purpose of the Report and Conclusions:

In August 2006, the Alaska Legislature passed HB 3001 containing a new oil and gas production tax system called the Petroleum Profits Tax (PPT). The new profits-based tax replaced the previous production tax based on gross value, generally referred to as the “Economic Limit Factor” (ELF) tax system. Debate and passage of HB 3001 was contentious, with questions raised on the propriety of a profits-based tax and on the appropriate tax rate. The controversy escalated earlier this year with the handing down of federal indictments against several legislators that centered on potential corruption involving the PPT deliberations and votes.

The Governor tasked the Commissioner of Revenue with evaluating whether the PPT was meeting expectations with respect to state revenues and industry’s reinvestment in Alaska. The Commissioner of Revenue formed a Production Tax Team, staffed with members from the Department of Revenue, Division of Tax and the Department of Natural Resources, Division of Oil and Gas to review various aspects of PPT implementation. Based on the information provided by the Production Tax Team, the initial conclusions of the Department of Revenue are:

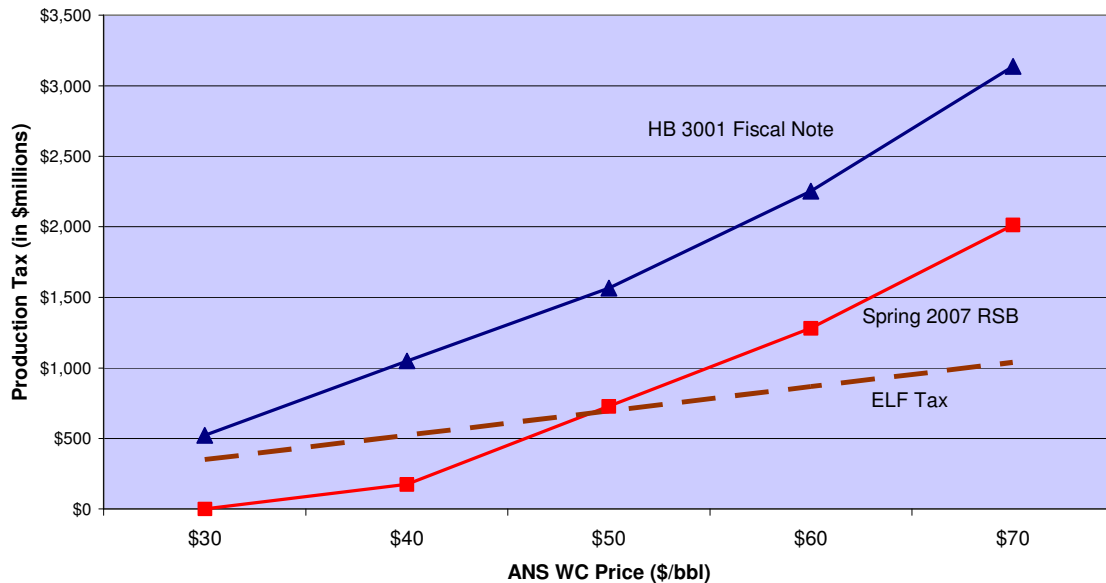
- 1) At current prices, the state is collecting more production tax revenues under PPT than it would have under the ELF system. However, those revenues are falling far short of what was expected when PPT was passed.
- 2) Operating and capital costs are substantially higher than were forecasted in the PPT fiscal note provided to the legislature.
- 3) The value of PPT credits may not be fully realized for exploration companies new to Alaska, given the small market for resale among “producers.”
- 4) The crossover oil price point where the state receives more revenue under the PPT than under the ELF system has moved from the \$26/barrel predicted in the PPT fiscal note to \$48/barrel.
- 5) The activation of the progressive surcharge has shifted from a market price of \$55 to over \$60 a barrel.
- 6) DOR faces significant challenges in implementing the PPT as currently structured.

II. Discussion:

1) Production tax revenues are falling far short of expectations. The following graph shows the differences in modeling results for FY 2008 production tax revenues; this graph compares initial modeling for FY 2008¹, as prepared for the House Bill 3001 (PPT) fiscal note [SCS HB3001(NGD)], with current modeling, as prepared for the *Spring 2007 Revenue Sources Book*, and with the tax revenue that would have been generated under the ELF system. The tax revenue expectations for FY 2008 are significantly lower than the revenue forecasted when the fiscal note was drafted. This is primarily due to the significantly higher costs being reported as compared to what was estimated in the fiscal note, as noted below.

In FY 2008, based on forecasted price and production levels, the PPT is expected to generate about \$250 million over that which would have been generated under the ELF system. However, this is more than \$800 million less than what was predicted in the PPT fiscal note.

FY 2008 Production Tax Estimates: HB 3001 (24th Legislature) Fiscal Note and Spring 2007 Revenue Sources Book PPT Forecasts; and ELF Tax



Note: Above estimates are based on most current taxpayer-submitted expenditure forecasts and do not reflect any changes in spending due to increases or decreases in oil price.

¹ Because of the unexpected disruptions to revenues and costs caused by the gathering line failures in the Prudhoe Bay Unit in FY 2007, the Department is using FY 2008 as the comparison year to eliminate one-time aberrations. In addition, the HB 3001 Fiscal Note and ELF Tax models have been adjusted to reflect current production estimates.

2) Operating and capital costs are substantially higher than were forecasted in the PPT fiscal note. The substantial and unanticipated increase in costs is the primary reason revenues are falling short of expectations. Throughout the latter half of 2004 and 2005, DOR officials gathered information from confidential tax documents, annual reports, private consultant analyses, and the industry about the costs of producing petroleum on the North Slope. DOR modeled the PPT revenue forecasts using these cost data and the results of this modeling were provided to the legislature to aid their consideration of the PPT.

Based on the cost data received by the Department for 2006 and 2007 since passage of PPT, the Department has increased by almost 100% taxpayer operating and capital cost estimates for FY 2008 in its Spring 2007 Revenue Source Book revenue projections. In discussions with taxpayers, DOR has been told that these higher costs levels for 2006 and 2007 are not aberrations caused by unique events, such as the Prudhoe Bay shutdown, and that we should anticipate costs remaining at these levels for the foreseeable future.

**North Slope Production and Costs FY 2008,
per HB 3001 Fiscal Note and Spring 2007 Forecast**

	HB 3001 Fiscal Note	Spring 2007 Forecast
FY 2008		
Production (barrels per day)	802,000	764,000
Costs		
Operating costs (\$millions)	\$1,076	\$2,160
Capital costs (\$millions)	\$1,052	\$1,900
Total Costs	<u>\$2,128</u>	<u>\$4,060</u>
Total Costs per Barrel	\$7.27	\$14.56
Operating costs per barrel	\$3.68	\$7.75
Capital costs per barrel	\$3.59	\$6.81

High oil and gas prices since 2005 are frequently cited as the cause of these cost increases. Projects around the world that were once only marginally economic, are now considered very viable, and are now placing increased demands on limited supplies of engineering, procurement and construction services and on raw construction materials. The Upstream Capital Costs Index, developed by Cambridge Energy Research Associates (CERA), shows that costs for oil and gas production equipment, facilities, construction materials and personnel have increased 53% since 2005. CERA expects cost escalation to continue through 2007, although at a slower pace. Fluor Corporation estimates that prices for fabricated structural steel have increased 60-70% from 2003 to 2006, and that delivery times for these materials increased by 18-20 weeks from their previous levels. The same company reports that prices for seamless and welded pipe used in petroleum production have increased 80-160% from 2003 to 2006, and expects increases of another 15-50% by 2009.

It is too early to tell whether all of the costs reported under PPT thus far are properly deductible. Also, it is too early to know whether the increase in reported industry spending in the state will result in increased future production, or whether the increase in spending can be attributed to changed behavior as a result of the incentives included in PPT. What we do know is that the costs used in the modeling for the PPT fiscal note have proven inaccurate.

3) The value of PPT credits may not be fully realized for exploration companies new to Alaska given the small market for resale among “producers.”

Under PPT, tax credits earned by investors and explorers may be transferred and sold to other taxpayers who have a production tax liability. Companies that have been issued credit certificates above and beyond the \$25 million that can be refunded by the state would presumably sell their certificates to the highest bidder. In the first year that the PPT has been in place, however, companies holding credit certificates report that there have been few buyers for the certificates, and that those offering to buy them are doing so at large discounts.

4) The oil price crossover point where the state receives more revenue under the PPT than under the prior ELF system has moved from \$26/barrel to \$48/barrel.

The ELF system “crossover point”—that is, the Alaska North Slope - West Coast (ANS WC) oil price whereby the PPT generates more revenue than the ELF system—was the focus of some attention during the 2006 legislative session. Primarily due to the increase in the cost estimate, the currently estimated crossover point is substantially higher than was projected in 2006.

5) The activation of the progressive surcharge has shifted from a market price of \$55 to \$60-63 a barrel. Because the surcharge is not activated until the taxpayer’s net income per barrel exceeds \$40, higher costs have depressed taxpayer net income, thus delaying the price at which the surcharge kicks in. In addition, as production declines, the price at which the progressive surcharge is activated will move higher as costs are spread over fewer barrels. Although the level differs for each individual taxpayer, the North Slope average progressivity trigger is now estimated to be somewhere between \$60 and \$63 per barrel.

6) DOR faces significant challenges in administering the PPT as currently structured.

a) Regulations- The second phase of PPT regulations has been delayed as a result of the challenge of accurately describing the allowed and disallowed lease expenditure deductions.

b) Revenue Forecasts- The Department has been severely hampered in its ability to provide the administration and the legislature with accurate revenue forecasts because the department lacks future capital and operating expenditure information. The Department is in the process of rectifying this problem by requiring operators to provide forward-looking cost data, when and as provided to the unit working interest owners.

Statutory changes may be required to fortify and focus these requests for unit cost information.

c) Audits- With the passage of PPT, the department was authorized to hire eight auditors and one tax technician to assist with the additional audit requirements of the new tax structure. To date, the department has successfully filled the three most senior auditor positions, and has reduced the skills requirements for the remaining junior level auditor positions in light of the challenges of matching competitive pay with the more senior level skill sets.

The complexity of auditing production tax has increased several fold under the PPT, and the PPT increased the number of determinations an auditor must make. The provisions in the PPT which are intended to simplify and streamline these determinations through reliance upon unit owners' auditing of unit operators may assist this process, but we have not yet been through an audit cycle to assess the efficacy of this approach.

III. Conclusion

The state's experience with PPT puts a spotlight on the risks associated with a net profit-based tax system. The new system introduced the added variable of costs into the oil revenue equation. While it is a risk that is inherent in the decision to approve a net profit-based tax, the question is whether the magnitude of the risk was fully understood by the legislature given the information provided to them. While costs would be expected to increase, the dramatic difference between what was predicted and what has actually been experienced brings into question whether the legislature made its decisions based upon appropriate information.

Another aspect of PPT, the tax credits given for capital expenditures, has been significantly reduced in value due to the lack of an efficient market for those new exploration companies looking to sell their credits to those who have current production. This deficiency is particularly troubling because these new exploration companies are the ones that provide the state with the greatest opportunity to encourage new production that might not otherwise occur.

Clearly, there are aspects to PPT that should be re-examined by the legislature. In particular, the legislature should reassess whether the state is getting its fair share of oil and gas revenues, and whether the credits are designed optimally to provide the maximum impact on the state's goal of encouraging investment that leads to more oil and gas production.

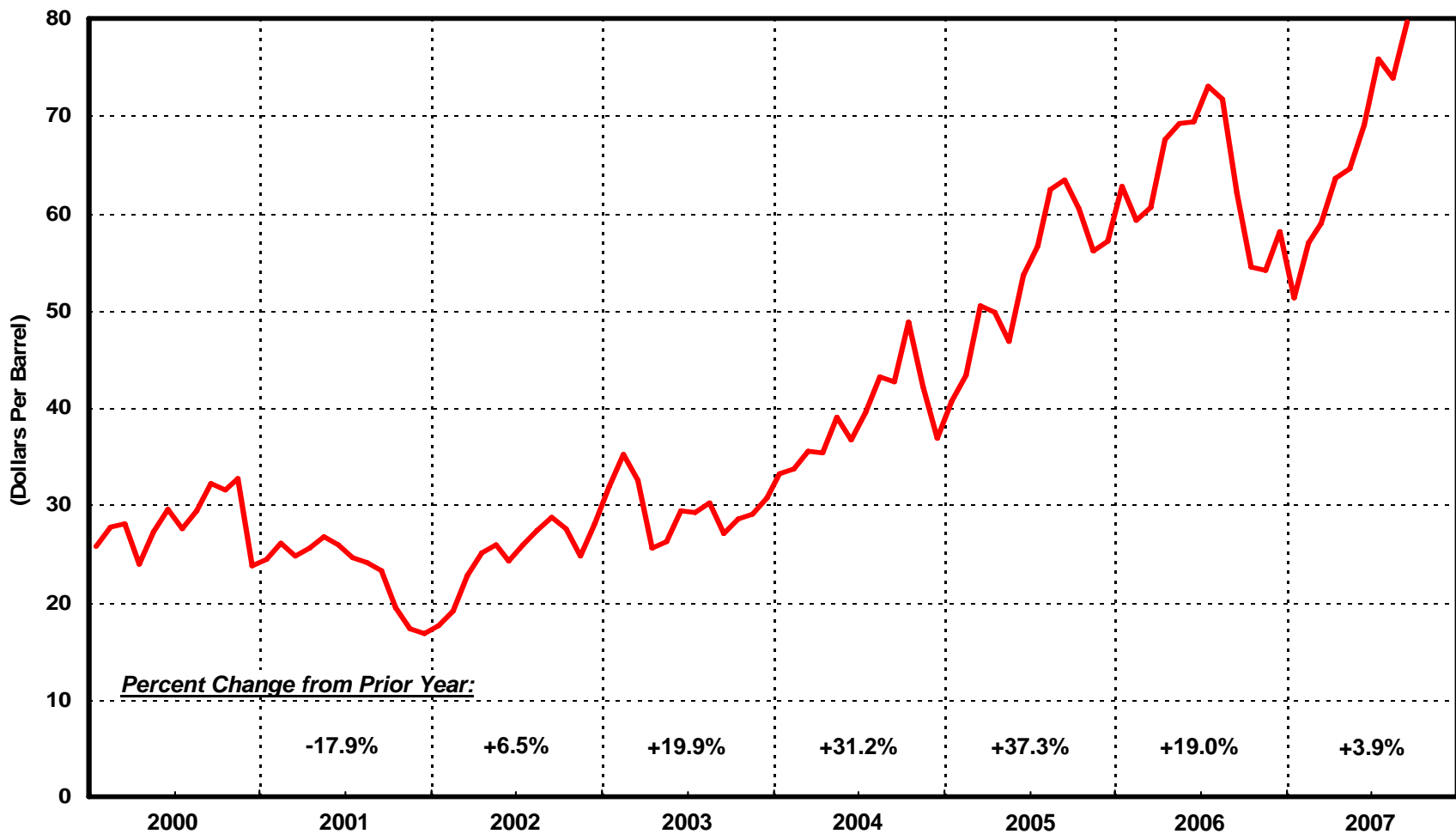
Attachment 2

**Summary of Cost Assumptions in
Fiscal Note to HB 2001 (ACES)
FY 2008 - FY 2014**

FY	Operating Costs	Capital Costs	Operating and Capital Costs
(Million Dollars)			
	(1)	(2)	(1) + (2) (3)
2008	\$2,146	\$2,187	\$4,333
2009	2,286	1,932	4,218
2010	2,375	2,024	4,399
2011	2,464	1,950	4,414
2012	2,572	2,028	4,599
2013	2,638	2,021	4,660
2014	2,712	2,360	5,072

Attachment 3

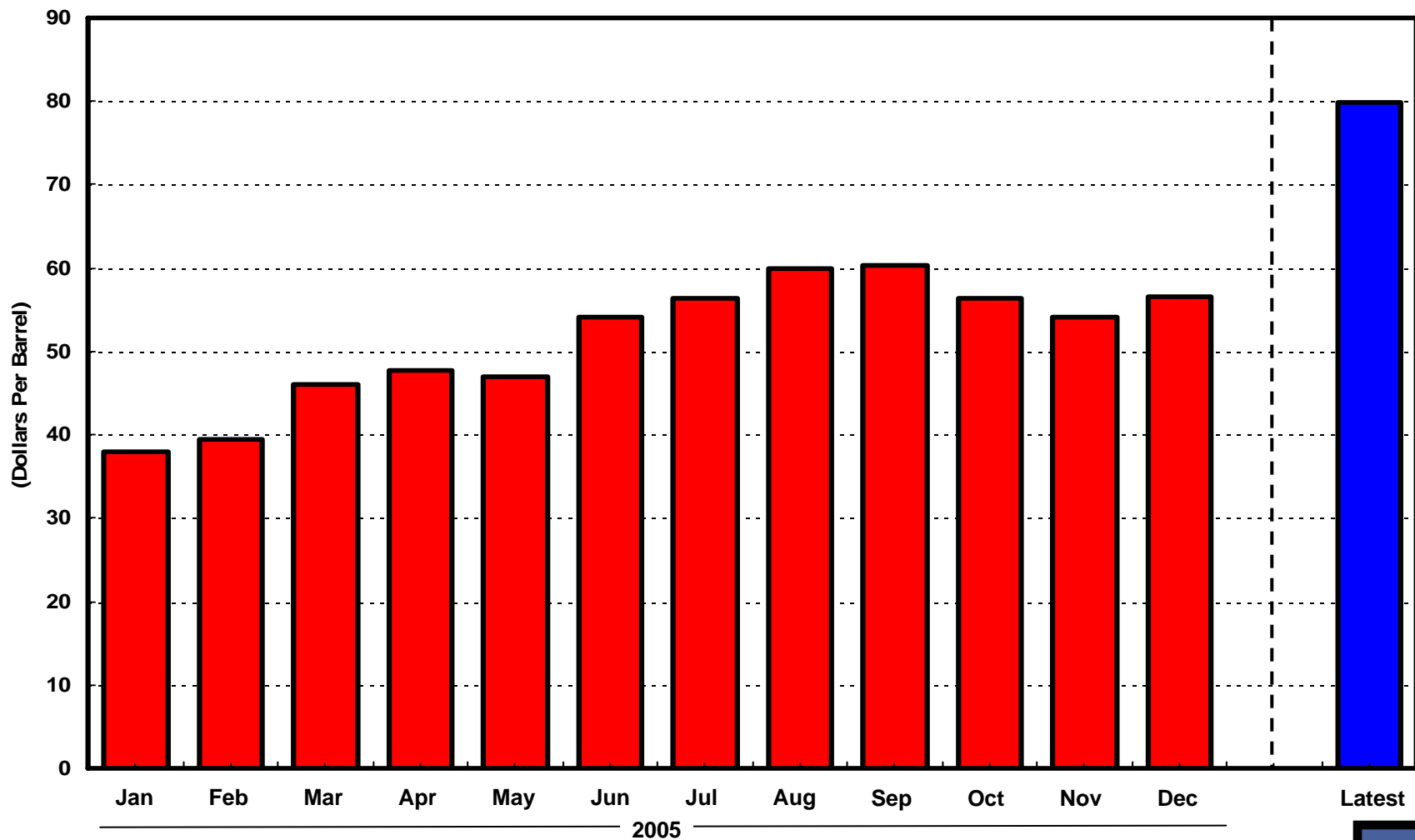
Platt's ANS Crude Oil Price January 2000 – September 2007



Source: Platt's.

Attachment 4

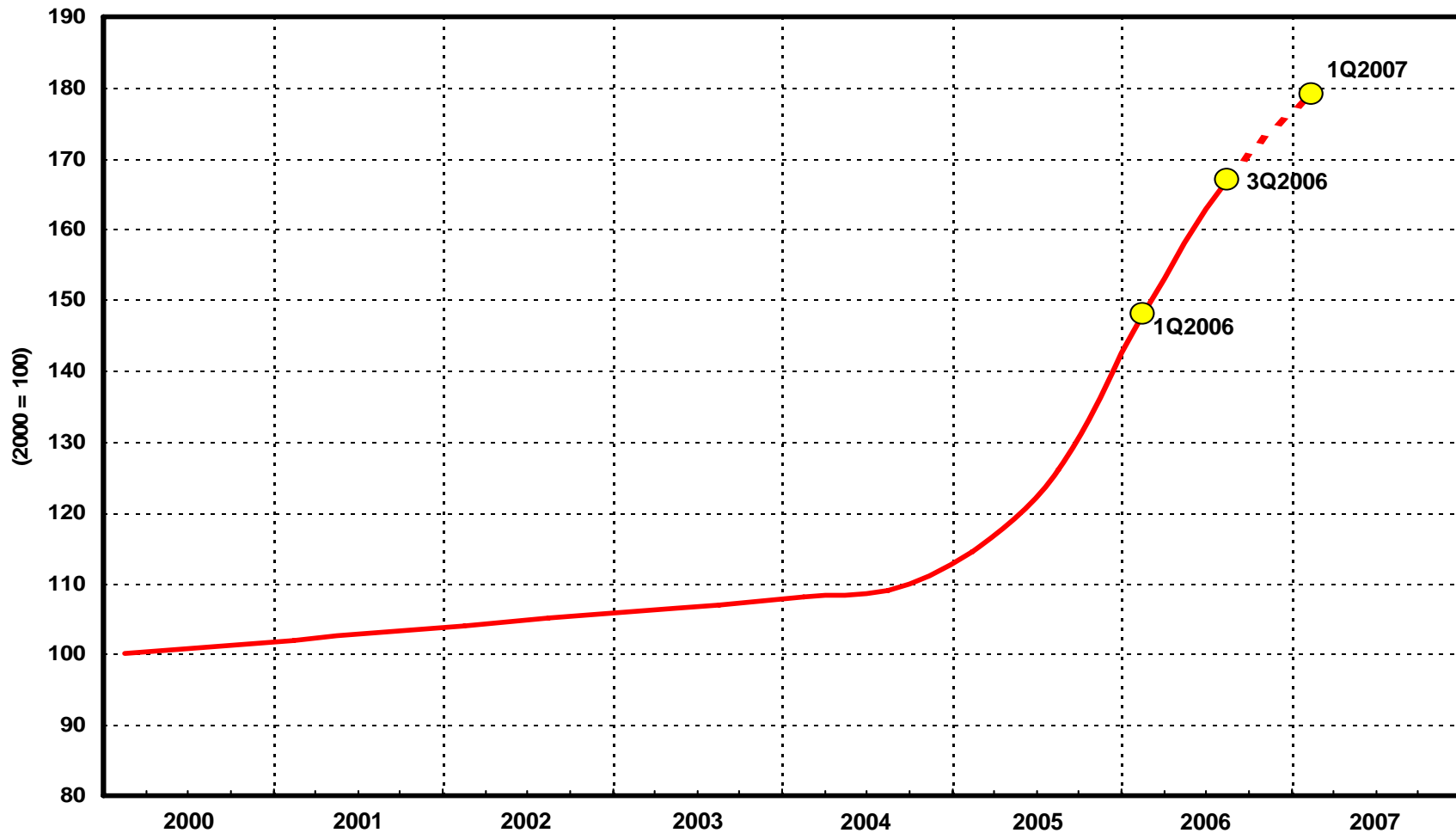
NYMEX Futures Price for December 2011 Delivery January - December 2005, Latest Quotes



Source: NYMEX.

Attachment 5

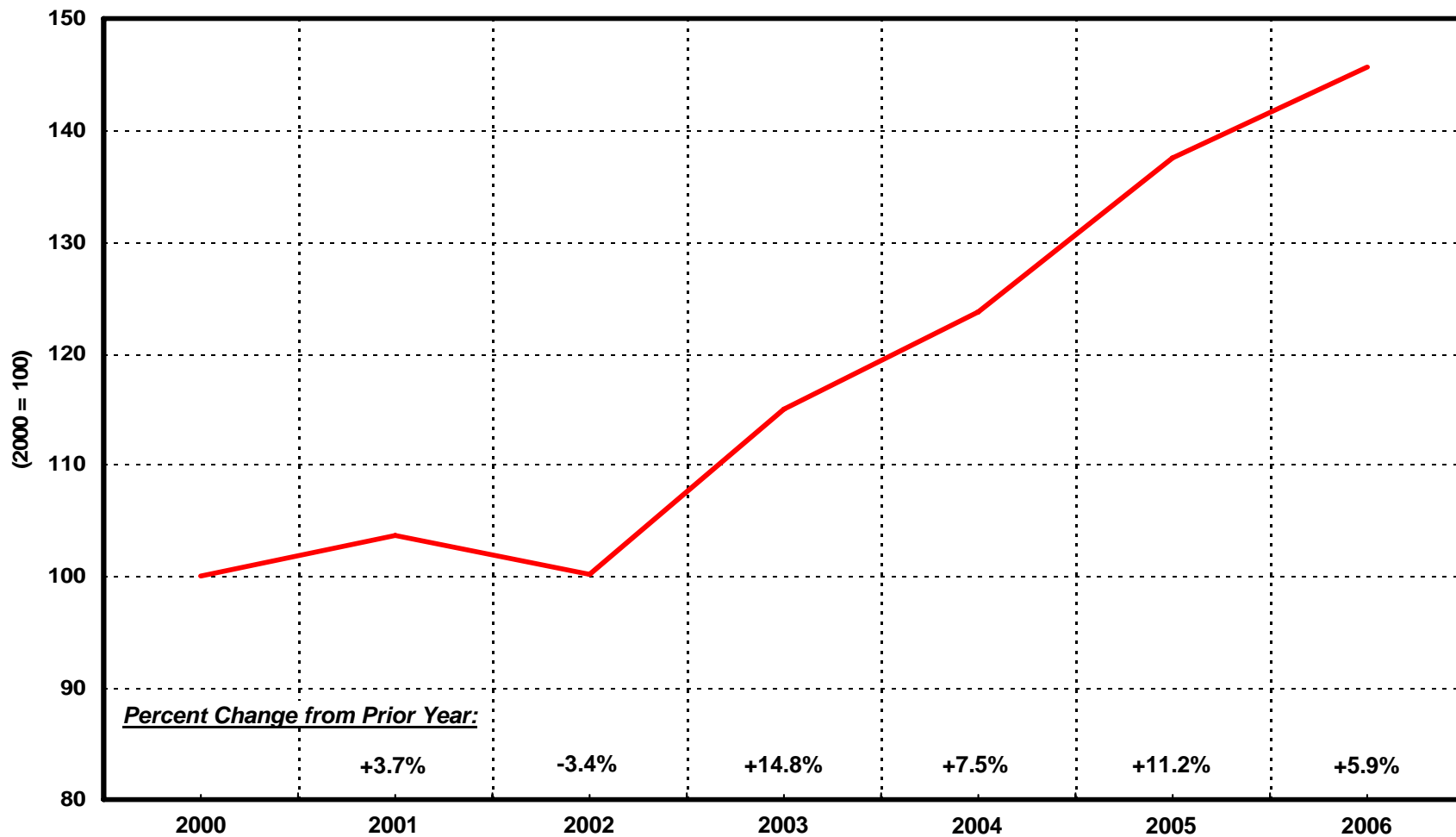
IHS/CERA Upstream Capital Cost Index 1Q2000 - 1Q2007



Source: Based on Cambridge Energy Research Associates May 8, 2007 Press Release.

Attachment 6

Average* Operating Costs for 10-Well Oil Lease Index 2000 - 2006

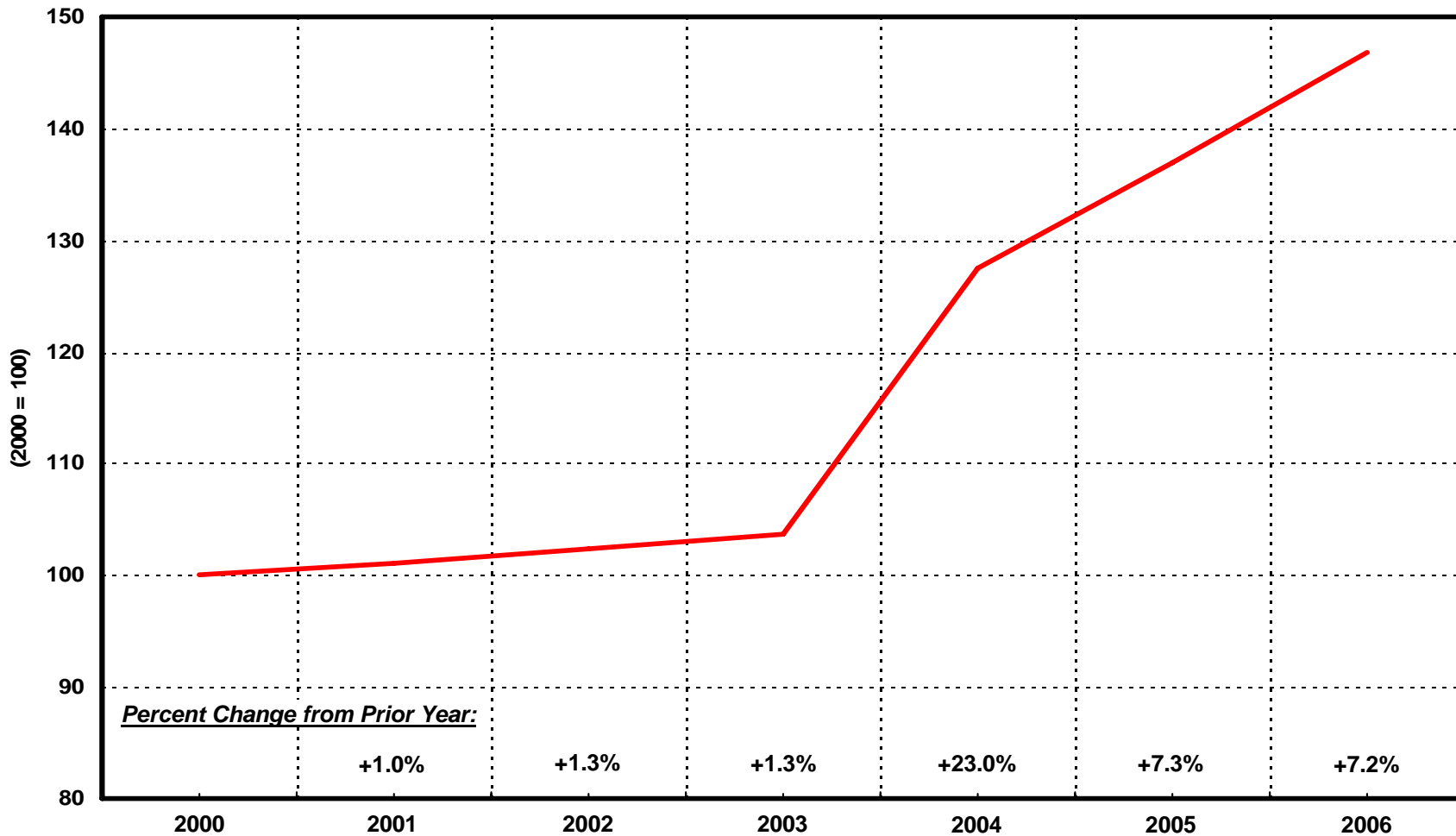


* Average of California, Oklahoma, South Louisiana, South Texas, West Texas, and Rocky Mountains.

Source: EIA.

Attachment 7

Average* Equipment Costs for 10-Well Oil Lease Index 2000 - 2006

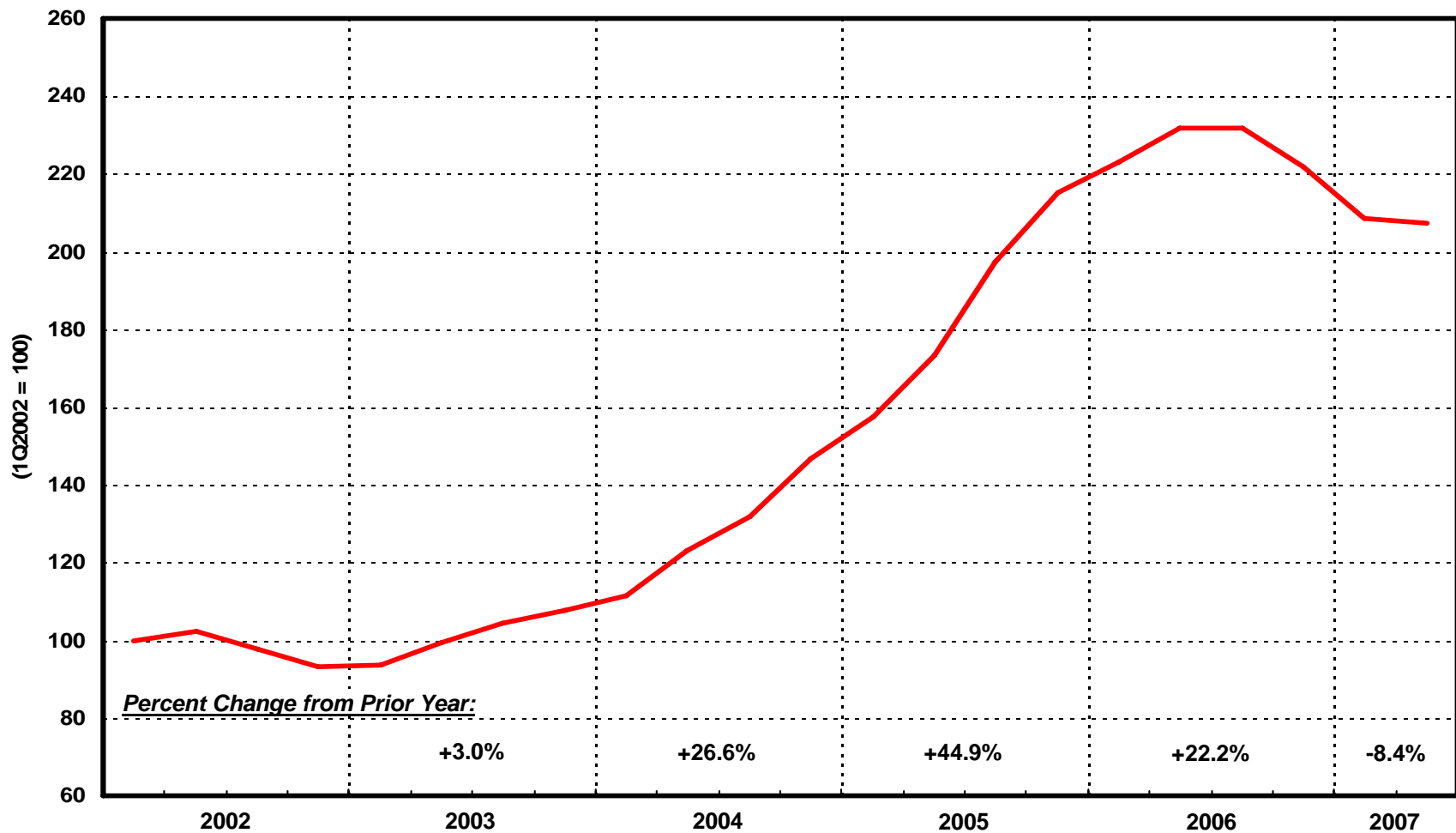


* Average of California, Oklahoma, South Louisiana, South Texas, West Texas, and Rocky Mountains.

Source: EIA.

Attachment 8

Average* Oil Drilling Rig Daily Rates Index 1Q2002 - 2Q2007

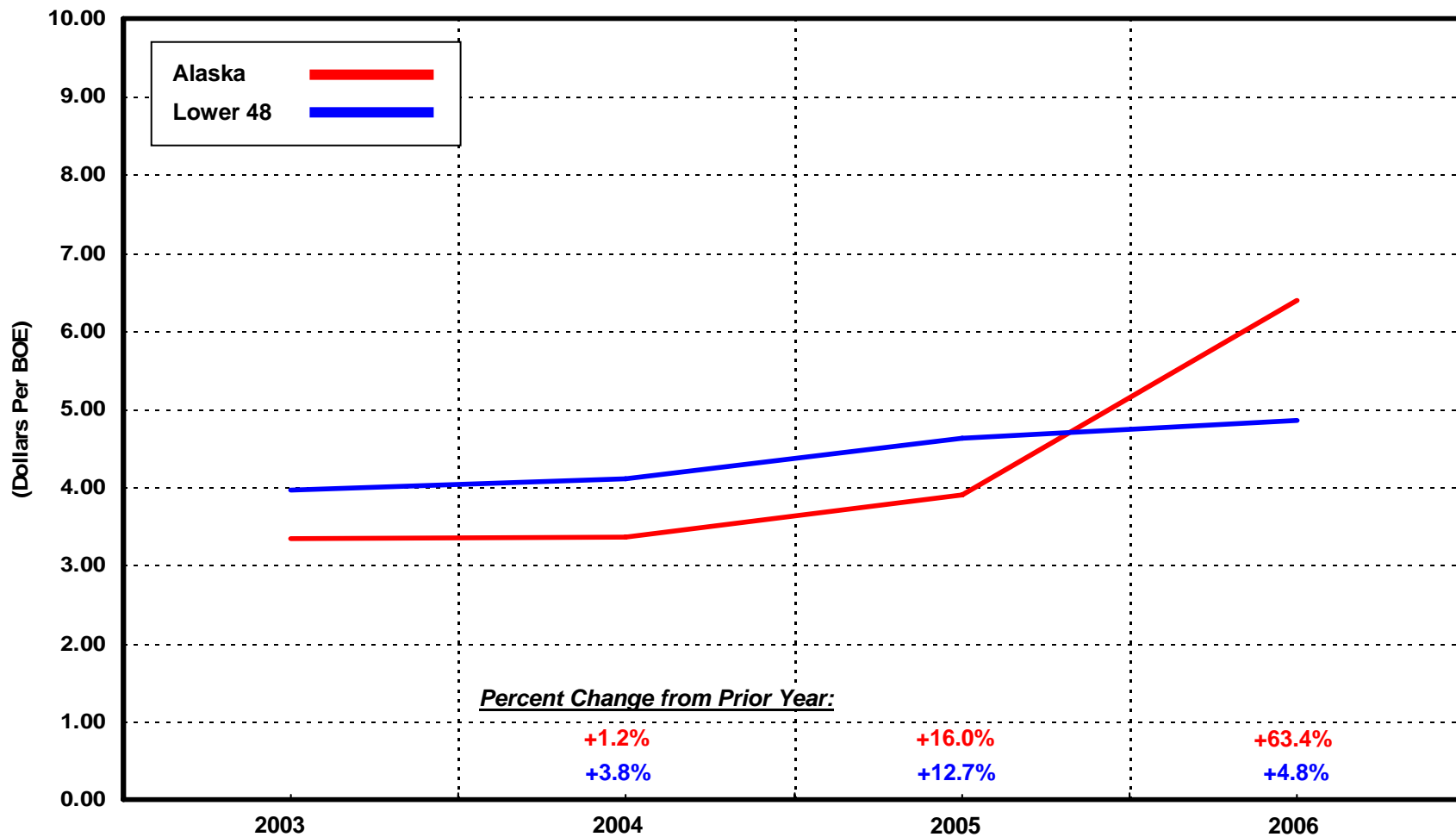


* Average of Mid-Continent, ArkLaTex, Gulf Coast, Permian Basin, Rocky Mountains, and South Texas.

Source: Land Rig Newsletter.

Attachment 9

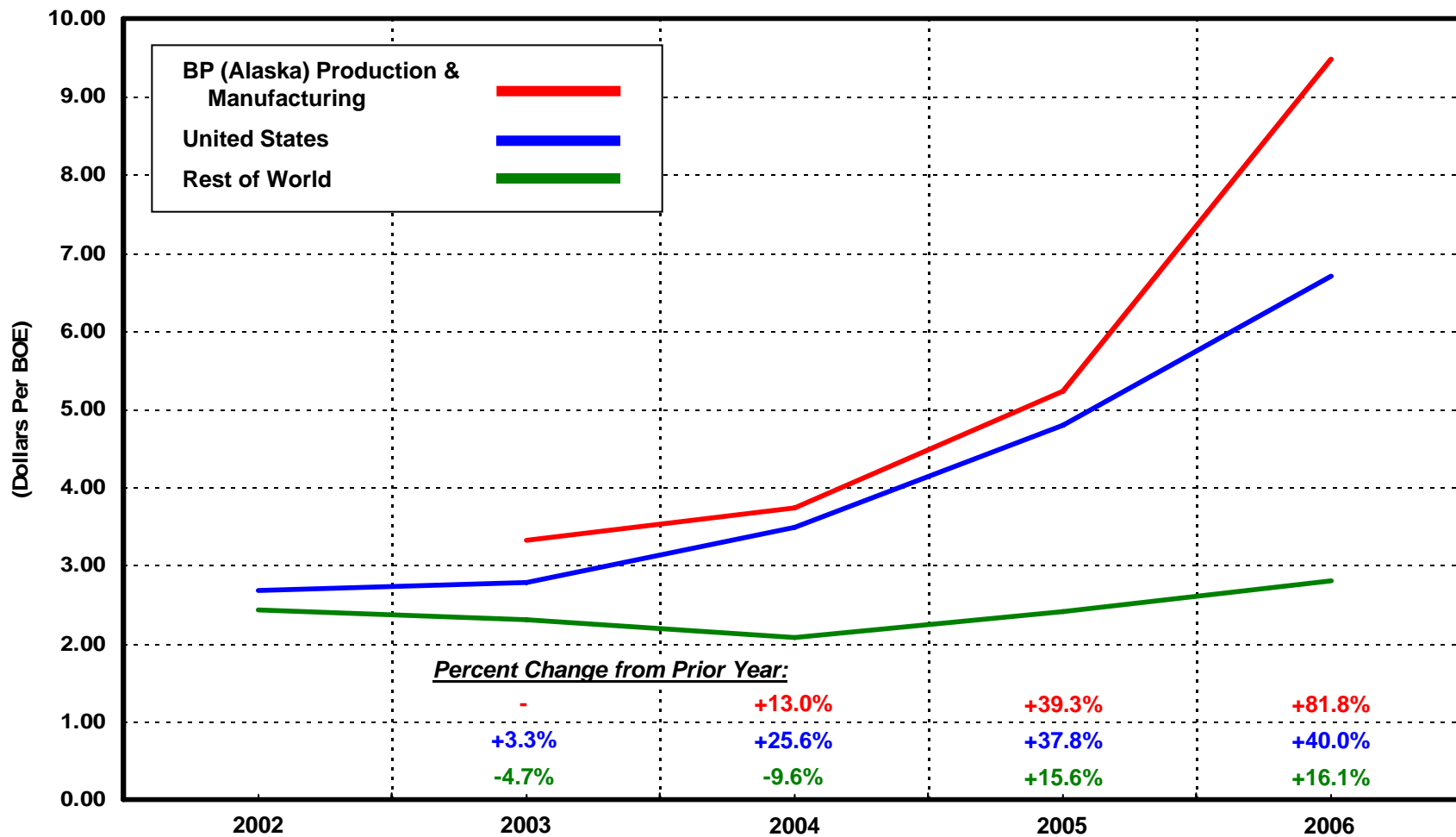
ConocoPhillips Reported Production Costs Per BOE 2003 - 2006



Source: ConocoPhillips 10-K filings.

Attachment 10

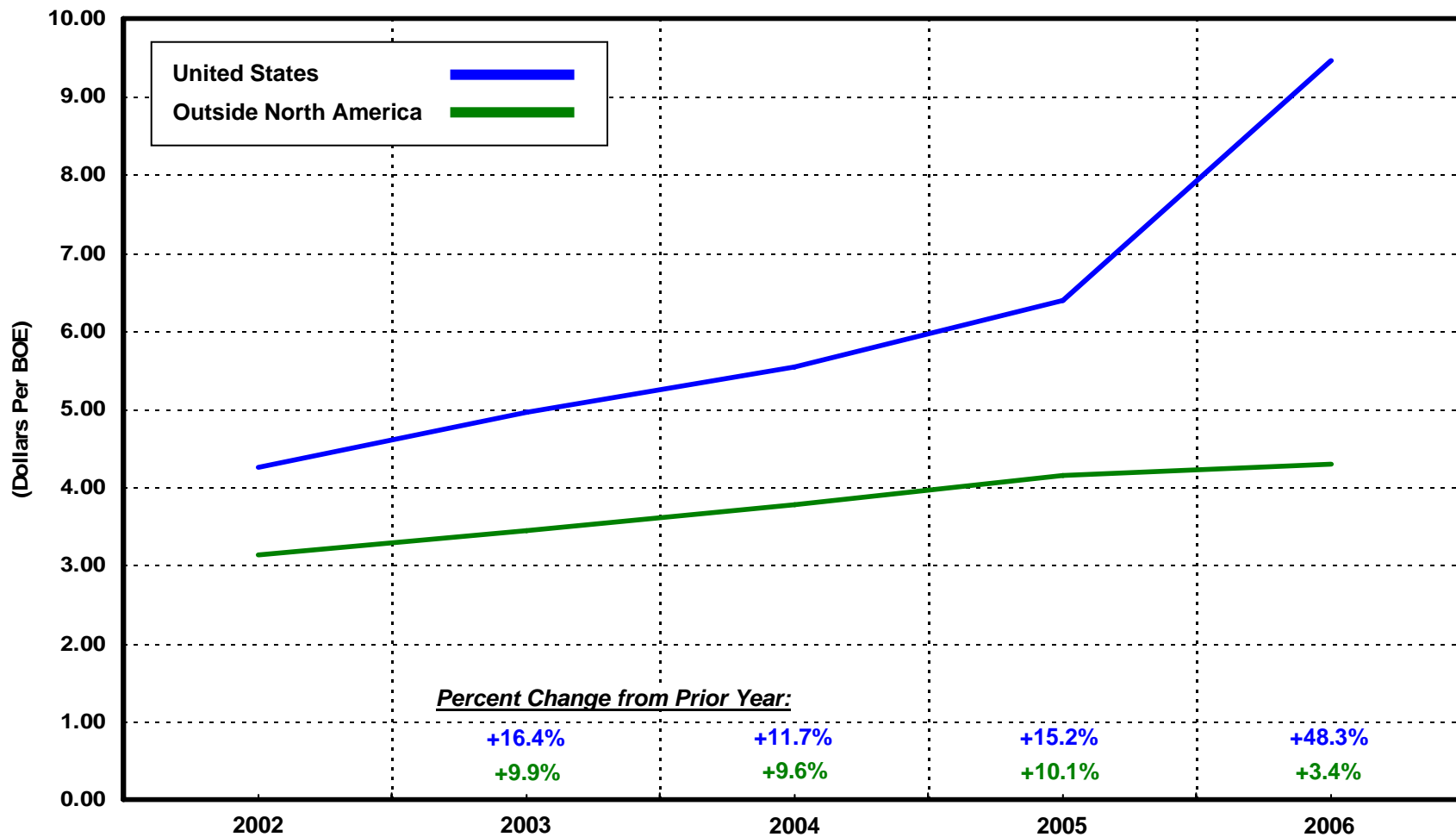
BP Reported Production Costs Per BOE 2002 - 2006



Source: BP Financial and Operating Information, 2002-2006.

Attachment 11

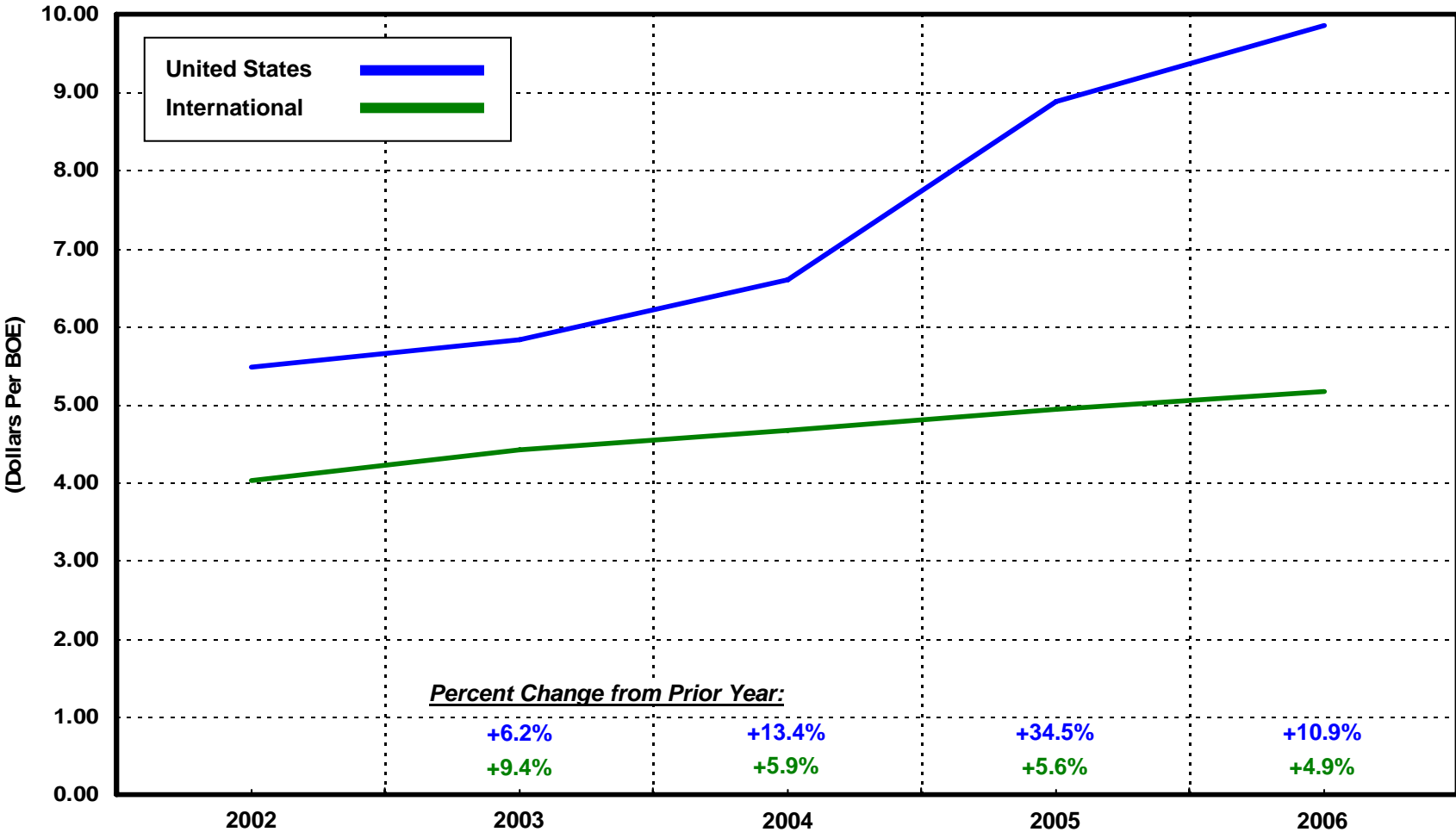
ExxonMobil Reported Production Costs Per BOE 2002 - 2006



Source: ExxonMobil Financial and Operating Review, 2006.

Attachment 12

Chevron Reported Production Costs Per BOE 2002 - 2006



Source: Chevron 10-K filings.

