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CLINE



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October 10, 2007

MEMORANDUM

INTRODUCTION

For many years, Alaska taxed oil and gas production based on the 'gross' wellhead value of the oil and gas. In 2006, Alaska passed legislation putting into place a Petroleum Production Tax (PPT) that essentially taxes production on the 'net' wellhead value of the oil and gas. With government take under PPT significantly below forecasted expectations, the State is again looking at possible changes to its petroleum fiscal policy. As part of the review of its oil and gas fiscal systems, the State of Alaska has asked Gaffney, Cline and Associates (GCA) to comment on its experience in working with many international governments on the relative merits and shortcomings of 'gross' tax structures versus 'net' tax structures.

In all but one country in the world, the state (government) owns the rights to all minerals. Bar very minor exceptions, it is only in the United States that private individuals can own mineral rights. In Alaska, the State owns the rights to minerals making it similar to other international locations.

States then lease or grant those mineral rights to petroleum companies for a period of time either via some form of licensing, concession, service agreement or production sharing agreement. In exchange for receiving the rights to exploit hydrocarbon resources, the oil companies are generally obligated to share with the state the revenues received from the sale of the extracted resources. In an ideal world, the oil companies recover their costs and a 'fair' return on those costs commensurate with the degree of risk taken in developing the licensed acreage. The remainder of the cash flow – "Economic Rent" – would then flow to the government.

While in discussions of what is a fair level of government take a couple question inevitably arise:

- Why doesn't the state just develop the resources itself?
- Why do governments routinely turn to private capital?

Most often, the State does not have the requisite skills, technologies or resources to properly do so. Also, the capital required is significant. Many states do not have sufficient capital while for those that do, state development of hydrocarbon resources may not be the most efficient use of what is normally limited monetary resources.

Private capital is encouraged by giving investors the opportunity to expect returns better than other alternatives on offer. Returns are provided by sharing benefits. Sharing of benefits is a balance between a nation's right to benefit as the resource owner, and private capital's need to refresh its capital and to provide a sufficient return to its investors.

predictions further out in time are shown to be quite inaccurate when ultimately compared to the actual prices in those times. The most accurate predictor of future prices was the NYMEX commodity futures market for crude oil and gas. Even these forecasts only go out for five years at most and the majority of petroleum projects are on production for a decade or longer.

The challenge clearly then is defining a petroleum tax system that responds to market changes, not one based on predicted market conditions. Just as most 'expert' forecasts bear little resemblance to actual prices, fiscal systems based on predicted results often find themselves out of sync with actual realizations resulting in one or both parties seeking relief or change.

Another consequence of systems attempting to collect 100% rent is that they usually encourage a degree of "gold plating" as there are no incentives to keep costs down; in fact from the oil company's perspective additional 'profit' can only be earned by spending more as any gains in efficiency would flow through to the state. Additionally, the cost of capital, while generally measurable, varies by company, can vary by project and is also a function of a number of economic factors.

Gross Tax

There are many different aspects to petroleum taxation worldwide, and many different ways in which governments receive value for their minerals. At the macro-level the government take mechanisms are either based on revenue ('gross') or profits ('net').

The most common form of a gross tax is royalty. The main reason governments like royalty is that royalty provides the government with early and continuous cash flow. Royalty is based on sales revenue received (with no deductions), making it simple to administer and to audit. While royalty subjects the government to variations in product pricing it also insulates the government from the varying cost structures and operating efficiencies of the different oil companies.

Not surprisingly, royalty, and other gross taxes, are generally disliked by the oil companies. The biggest issue with royalty, or for that matter any gross based tax, is that it is not aligned with the way in which private companies operate. Oil companies make decisions on the basis of profitability, not production. Gross taxes delay payout, do not differentiate between profitable and unprofitable fields and, if no relief is granted, generally lead to premature abandonment (or deferred development) of hydrocarbon reservoirs. In an effort to balance the obligation to maximize recovery of hydrocarbons with the desire to capture 100% of the Economic Rent, governments tend to write into their taxation policies a number of allowances or exceptions in an effort to account for known or anticipated variations in cost structures.

For the most part, gross tax systems require legislative or regulatory change whenever there are substantive changes in the market.

Net Tax

The most common form of a profit or net-based tax system is corporate income tax. For many countries, this is the most common form of taxation and is levied against all industries, not

M E M O R A N D U M

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such as this is aligned with the way in which private companies function and does away with the need to offer up front concessions, investment credits and late life relief.

Attracting New Investment

New investment is necessary to keep oil field activity at the right level. In this regard, countries compete against each other for the limited oil company dollars. Alaska is looking for a fiscal system that will encourage the development of satellite, small and marginal fields as well as its heavy oil resources.

A gross-based tax does not give credit for new investment, nor does it differentiate between the various types of fields, levels of risk or relative profitability. To compensate, allowances or exceptions are generally made. These allowances must be made well in advance (in order to attract the investment dollar) and are based on best predictions at the time.

This is where a net-based system excels. Companies are allowed a deduction for their investment dollar with the government sharing in the costs of that investment. If costs are higher for one type of investment versus another, a net-based system is self-correcting in that it allows a greater deduction for the higher cost development thereby limiting the need for exceptions or allowances. In comparing net based systems, the rate of capital recovery becomes important.

Fiscal Stability

The United Kingdom (UK) is a country often mentioned as having one of the most stable fiscal systems; however, the UK has made more changes to its petroleum fiscal policy in the past 30 years than almost every other country. The reason the UK is viewed as stable while undergoing fairly constant change is that the modifications were responsive to changes in market conditions. Total taxes were raised or lowered depending on market circumstances. In short, the industry appears to view a flexible structure adapting to changing conditions as a stable structure.

Net-based tax systems offer much more flexibility and resilience than gross-based systems. Net-based systems also need less tinkering as many aspects of those systems are self-correcting. However, good fiscal design without complementary institutional structures may still not achieve the desired goals. The ultimate system chosen by any government is generally within the administrative and audit capacity of its relevant institutions. So long as it gets access to the right data and is ably administered and audited, a sophisticated net-based system will be a more effective capturer of Economic Rents over the long run and should ensure that the jurisdiction remains competitive for petroleum investment dollars.

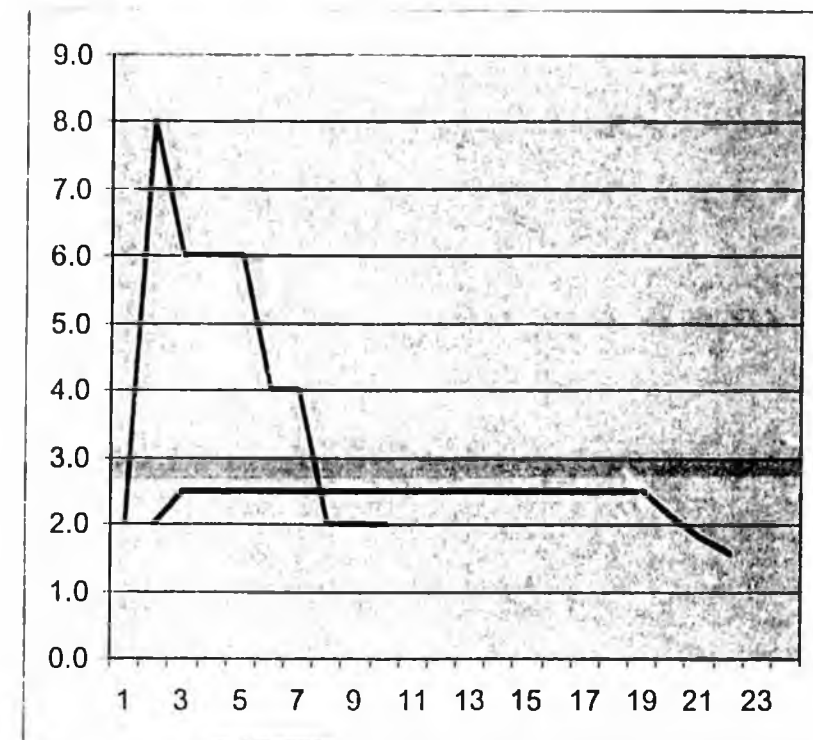
In summary, net today is best practice; some countries are switching back to gross but they are not systems to benchmark (Venezuela, Bolivia, etc.). If a regime is sophisticated enough to have a net based corporate tax system (and almost all countries have one) then it is sophisticated enough to administer a net based petroleum tax. Access to the right type of data on a timely basis is key.

Payout

10-21-07

What is expectation as to the time to recover initial investment?

- **Simple answer – As soon as possible!**
- **Rule of thumb – from date of first production plus:**
 - Oil – 3 to 6 years
 - Gas – 5 to 9 years
(combination of higher costs and lower BOE)



Other Countries - PSC

- **Production Sharing Contracts**

- Recovery of costs is commonly known as “Cost Oil”
- Range of annual cost recovery varies
 - Some put no cap on cost recovery
 - Others may cap cost recovery at say, 40% of revenue
- To compensate for particular situations the recovery may be ‘tweaked’
 - Uplift
 - Share of First Tranche Petroleum (aka Royalty)
 - The “tweaks” are to provide some compensation for the time value ‘loss’ of longer recovery times

Other Countries – Tax & Royalty

- **Basically speed of deduction and credits**
 - Depreciation period
 - 1,3,10 years
 - Depreciation method
 - Straight line
 - Declining balance
 - Depletion (based on production to remaining reserves)
 - Credits
 - An additional deductions equal to a percentage of qualifying investment

Another key impact

- **The “Ring Fence” can provide very different value to the oil company**
 - Consolidated by taxing district (e.g. the entire State of Alaska)
 - Immediately write off against other income streams
 - Progressive systems provide possible increased benefit
 - Ring Fenced say by individual field or reservoir
 - Usually have to wait until a discovery is turned into a development and revenue starts before the oil company can begin to recover their costs

Attractiveness of Exploration Credits

Alaska Exploration Investment Credits

- **One of the stated goals is to attract new exploration, new investment**
- **How does Alaska compare to other regimes?**
 - Compares very favorably on a global basis
 - State / Feds effectively becomes a major 'investor'
- **Comes close to leveling the playing field between incumbents and new entrants**
 - A feature that is not available in most countries
 - Usually there is a high barrier to entry

Alaska is offering...

- **Depending on parameters such as start date and distance from other existing oil and gas units and wells, investors can:**
 - Earn credits of 20% up to 40% of qualifying expenditures
 - Deduct money spent against current state and/or federal income tax liability
 - If no current PPT/ACES income can request and receive loss carry forward credits
 - Achieve favorable potential outcome after State/Federal Income Tax impact is considered
 - Contractor share – 21 to 36%
 - State/Federal share – 64 to 79%

Example

Example of timing of take

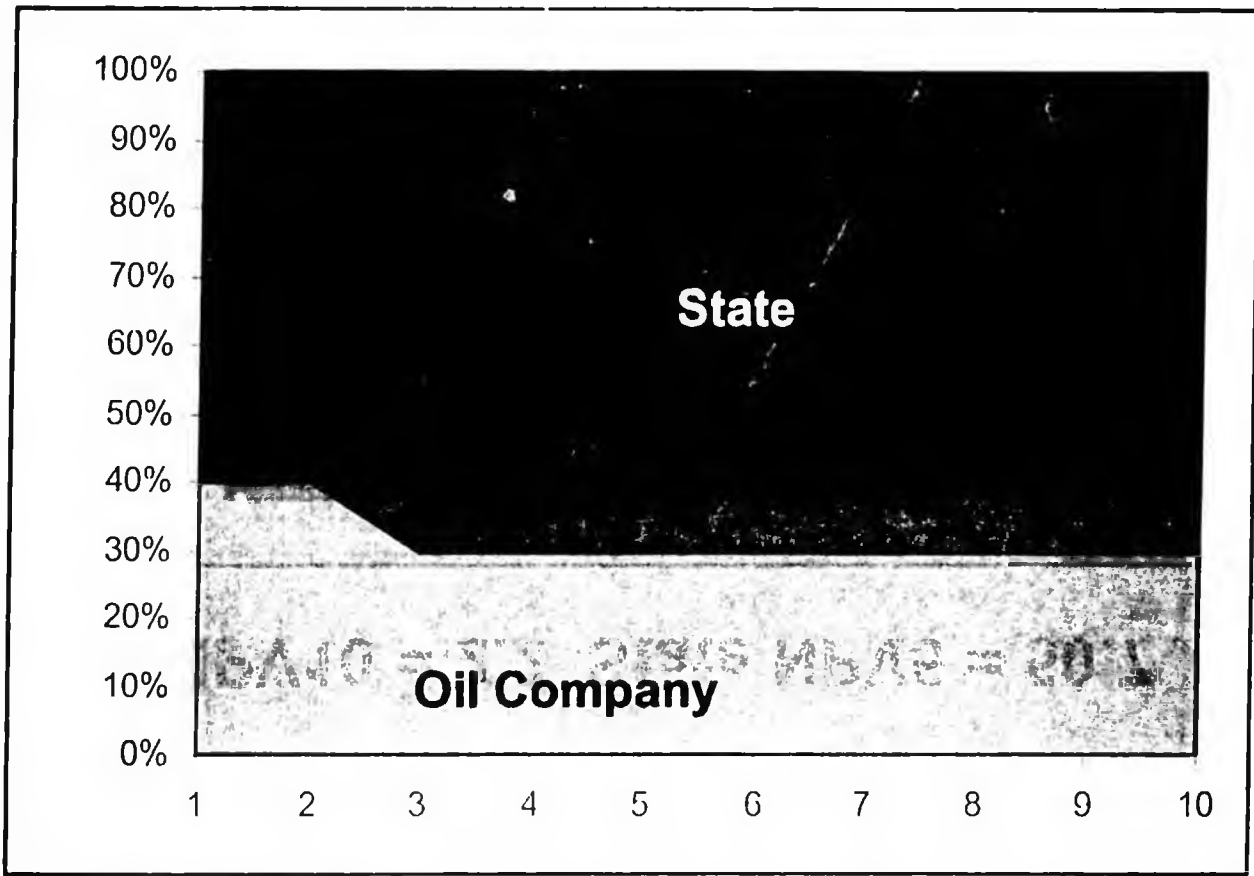
- **Assumptions**

- Investment of 20
- 10 years of flat cash flow = 100
 - 10 per year
 - Overall State gets 68, Oil Co gets 32

- **How does timing impact IRR (Internal rate of return), IOC NPV and State NPV?**

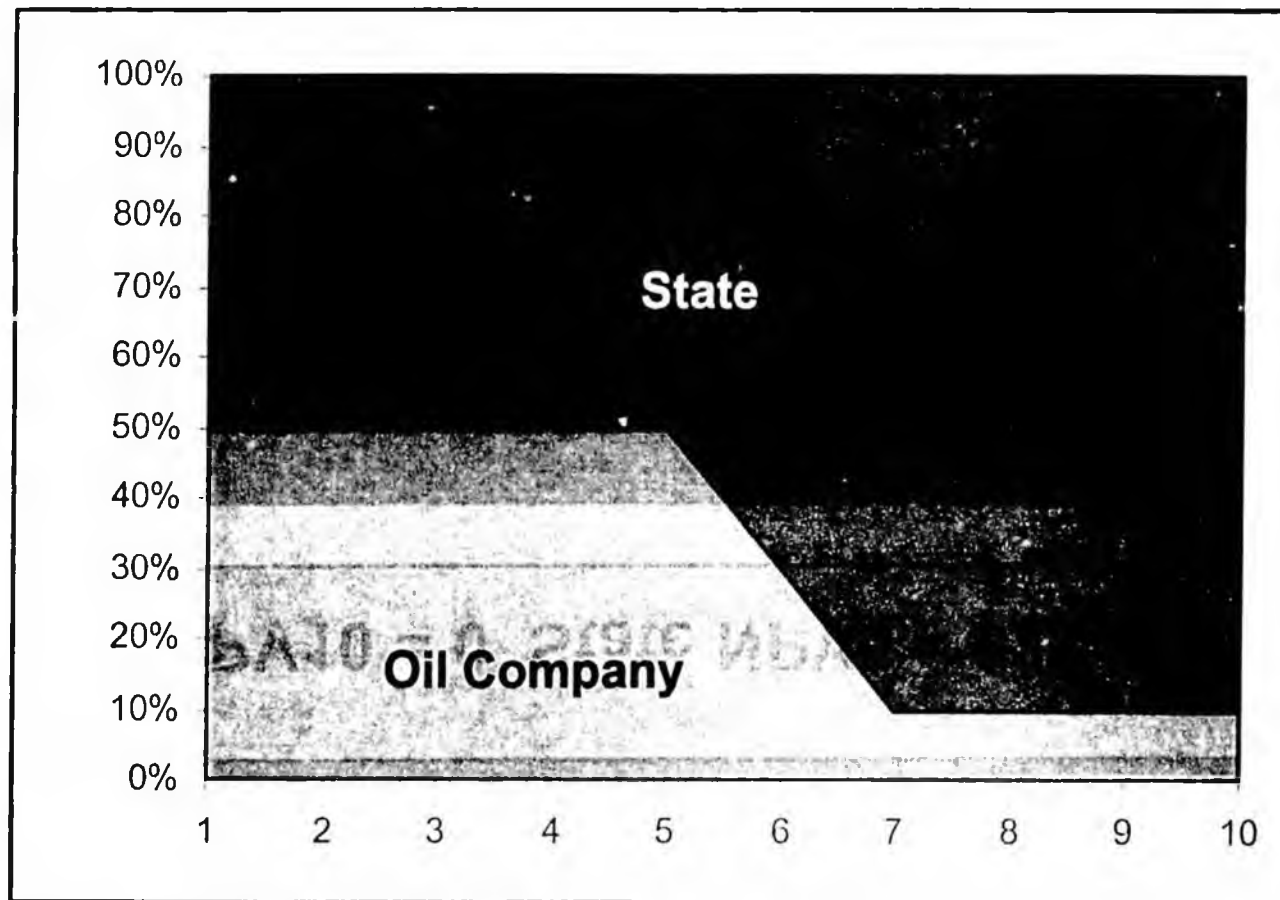
Case 1 – IRR 10%

- IOC NPV10 = 0 State NPV5 = 52



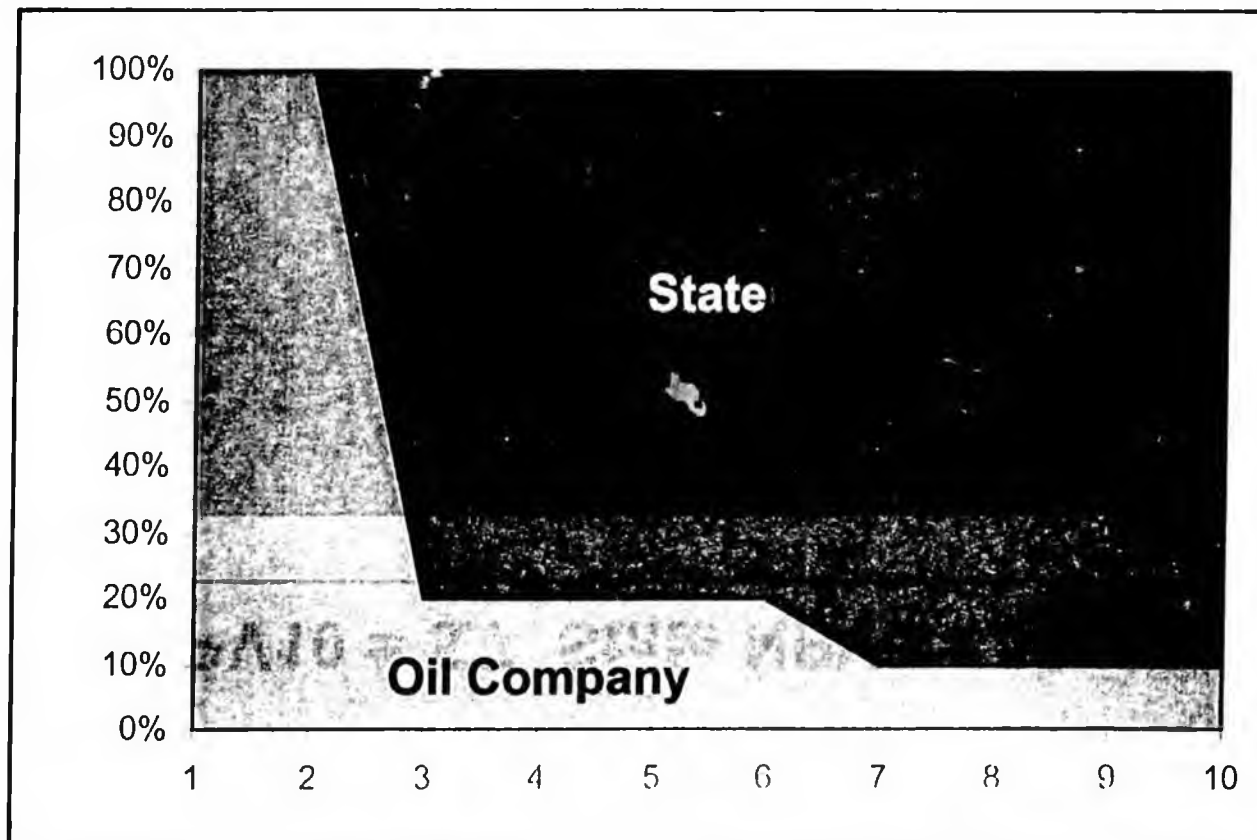
Case 2 – IRR 14%

- IOC NPV10 = 2.2 State NPV5 = 50.7



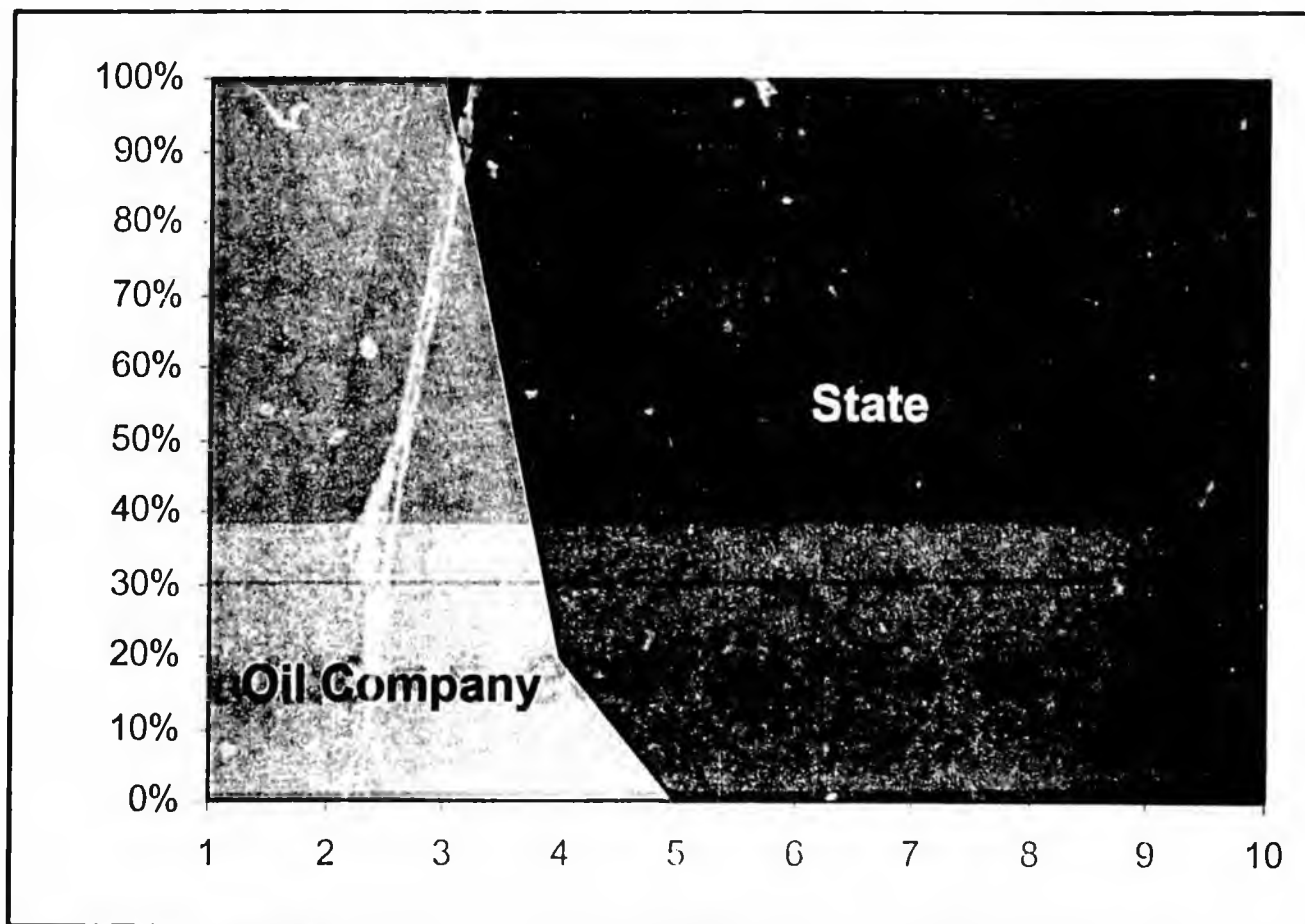
Case 3 – IRR 19%

- IOC NPV10 = 4 State NPV5 = 49.5



Case 4 – IRR 26%

- IOC NPV10 = 5.7 State NPV5 = 49.3



Alaska's Equitable Share

**Some Further Thoughts
30 October 2007**



Topics

- **What is the risk of raising state revenue share on the existing producing reservoirs?**
 - Look at AOGA, BP and other industry data
- **What are the goals or drivers for Alaska's Petroleum Fiscal System?**
 - List what we have discerned since arriving in Juneau
- **From a 50,000 foot viewpoint, what fiscal system structure accomplishes the above goals with a minimal need for intervention?**

The Tipping Point



Where is the tipping point?

- **Quite legitimately several legislators have asked their advisors and the companies how far is just right and how far is too far?**
 - The companies have complex decision making processes with many external factors at play and can't articulate what impact a change in Alaska taxes will have
 - Rock (Prospectivity) trumps Scissors (Fiscal) - Chevron
 - *Scissors (Fiscal) cut Paper (Profit)*
 - *Paper (Buy Reserves) covers Rock (Develop Reserves)*
 - Consultants acknowledge that taxes are but one of many factors that control decision making, and cannot say with certainty what tax rate is just right



Testing the Tipping Point

- **We can read lines, and between the lines, of industry testimony to construct a picture of the Alaskan investment climate**
 - AOGA letter which reflects “the full consensus of the members of the AOGA Tax Committee, with no dissent”
 - BP’s very detailed presentation on Prudhoe Bay area
 - Conoco’s useful insight on project economics
 - And other information supplied by Anadarko, Chevron, Exxon and Pioneer.
- **Details presented were then double checked against annual reports, SEC filings, analyst presentations and other company press releases where available**



Overall Observations

- **We agree with industry that there is significant upside in reducing the decline from existing producing assets**
- **The economics of reinvestment in producing assets on the North Slope are extremely profitable**
 - Evaluated with actual costs, production and prices as reported by BP
 - Profitable even when tested against various stress points



AOGA Testimony to the House

In discussing the merits of HB 2001 versus PPT and the Administration's concerns, we must always keep in mind the real-world situation that Alaska faces. The greatest challenge that confronts this generation of Alaskans and the next is the ongoing decline of oil production, which has been, is today, and promises to remain the cornerstone of the finances of state government.

- **The fiscal system chosen must recognize the current and near-term importance of improving production from existing assets.**



AOGA Testimony – Recent Success

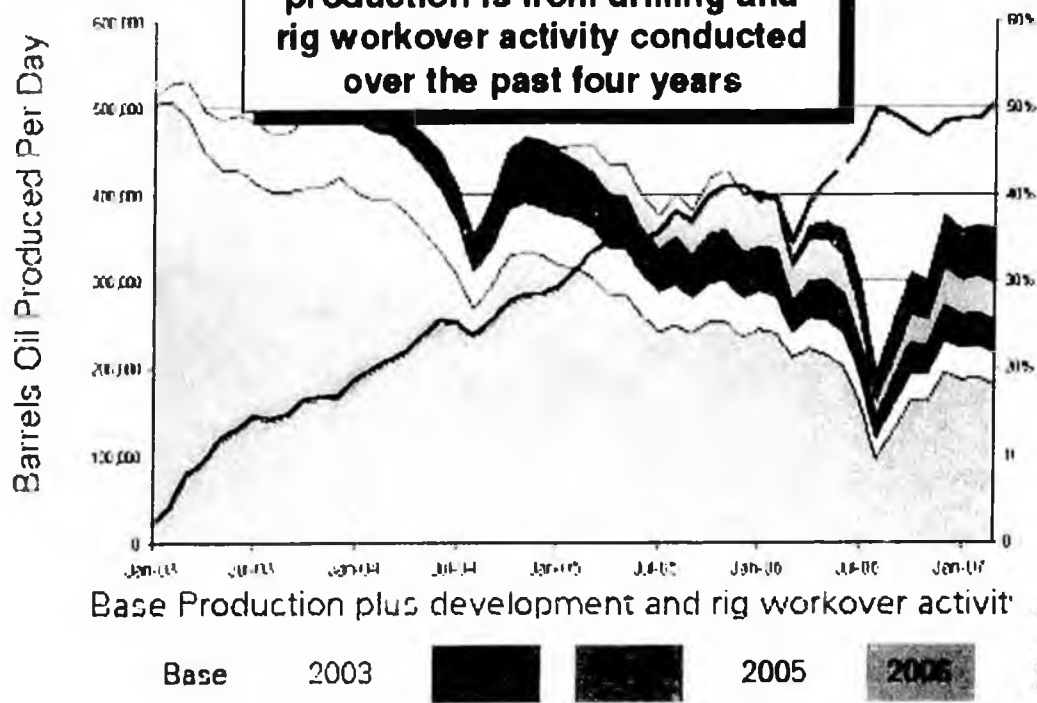
This gets us to investment in currently producing fields. Fortunately, there are investments that can be made, and are being made, in these fields to slow their decline. In the short term, this is in-fill drilling — that is, drilling new wells into the portions of a reservoir that are between the wells that have already been drilled. This accelerates the drainage of oil from the rock that currently lies in between existing wells. In-fill drilling last year contributed some 70,000 barrels a day to production from the Prudhoe Bay field. To put this into perspective, a 70,000 barrel per day field would be the 4th largest stand-alone field on the North Slope today.

- **AOGA noted that North Slope field life could be extended up to another 25 years with continued investment**
- **The oil companies achieved 70,000 bpd of additional production from the 2006 drilling program in Prudhoe Bay.**



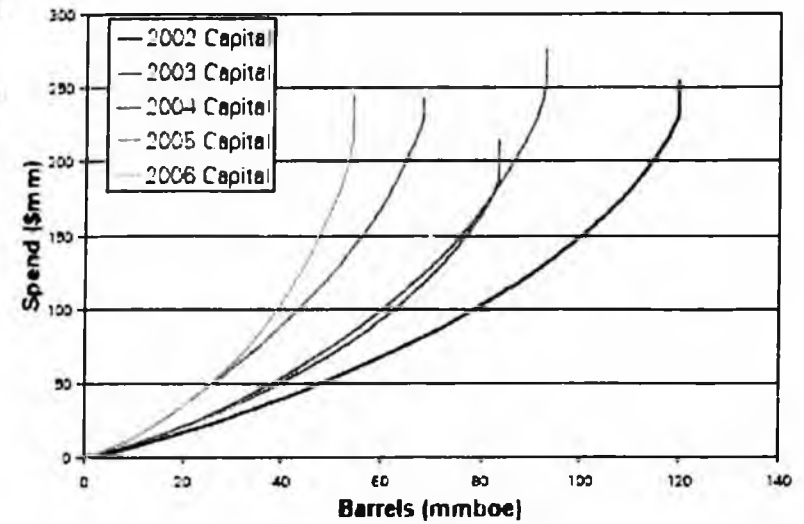
BP's infill drilling program

50% Of GPB's current oil production is from drilling and rig workover activity conducted over the past four years



Observations?

GPB Well Investments 2002-2006



BP House testimony page 12



Costlier Development

- It is getting more expensive to develop a barrel of reserves (BP Infill program)

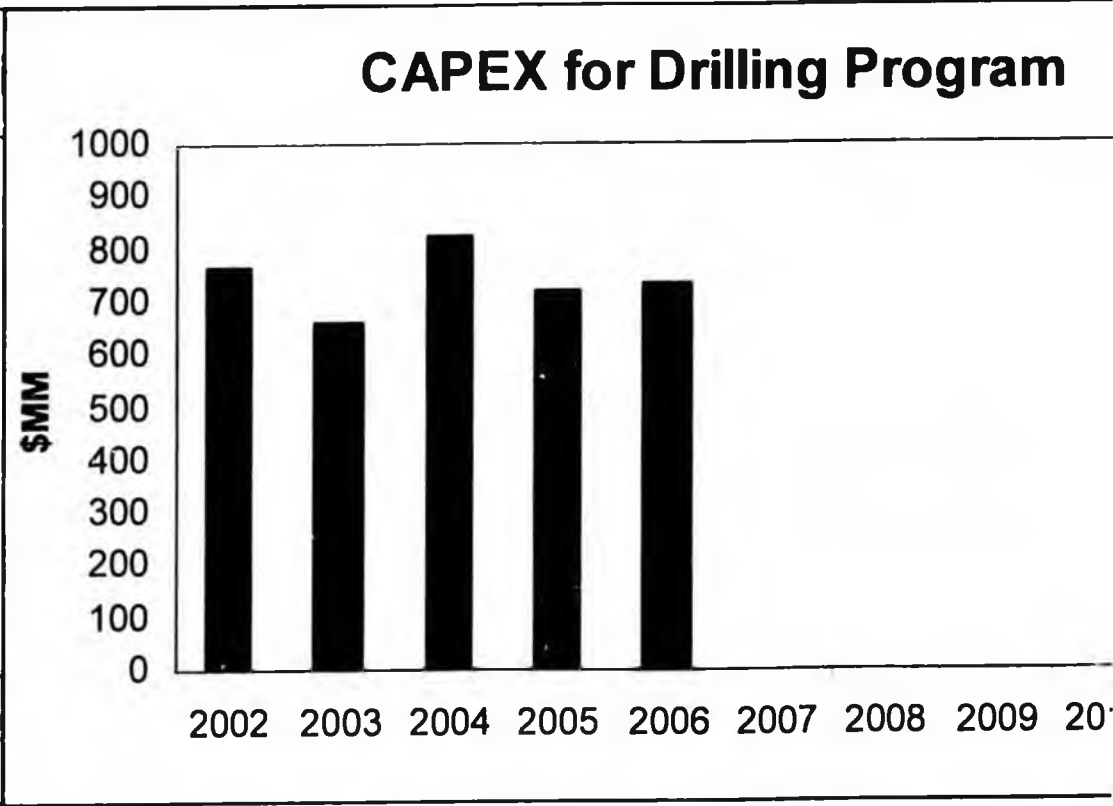
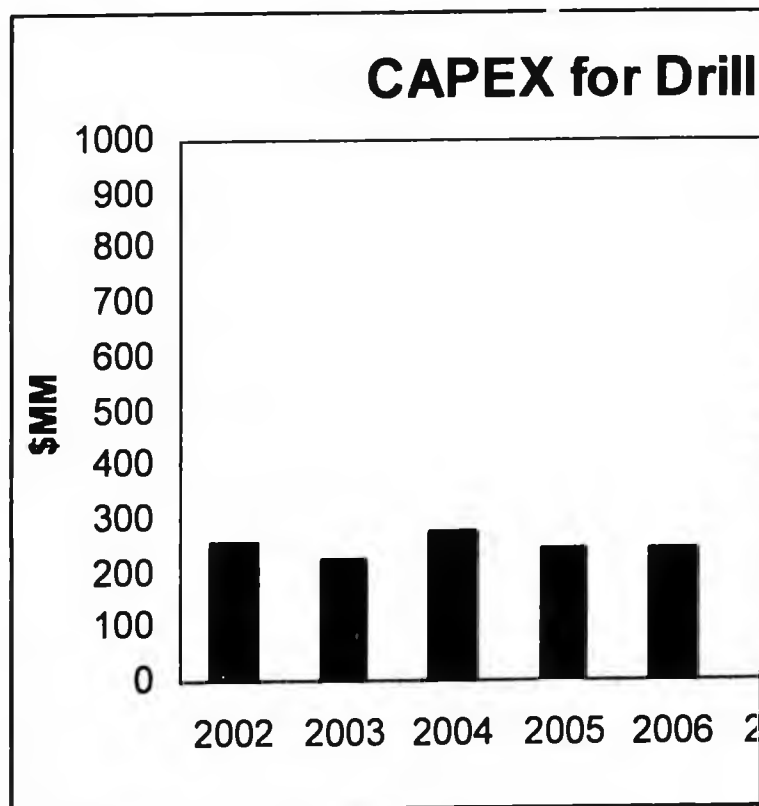
	2002	2003	2004	2005	2006
Capex	255	220	275	240	245
MMbbls	120	90	80	60	50
\$/bbl	2.13	2.44	3.44	4.00	4.90

- **Contrast the above per barrel F&D costs with:**
 - \$2 or less CAPEX for Prudhoe and Kuparuk to date
 - \$19bn to produce 9.5 bn bbls
 - The P/K upside at \$3.5(15%), \$7.7 (6%), \$12 (3%)
 - Pioneer's view of average F&D for Lower-48 of \$14



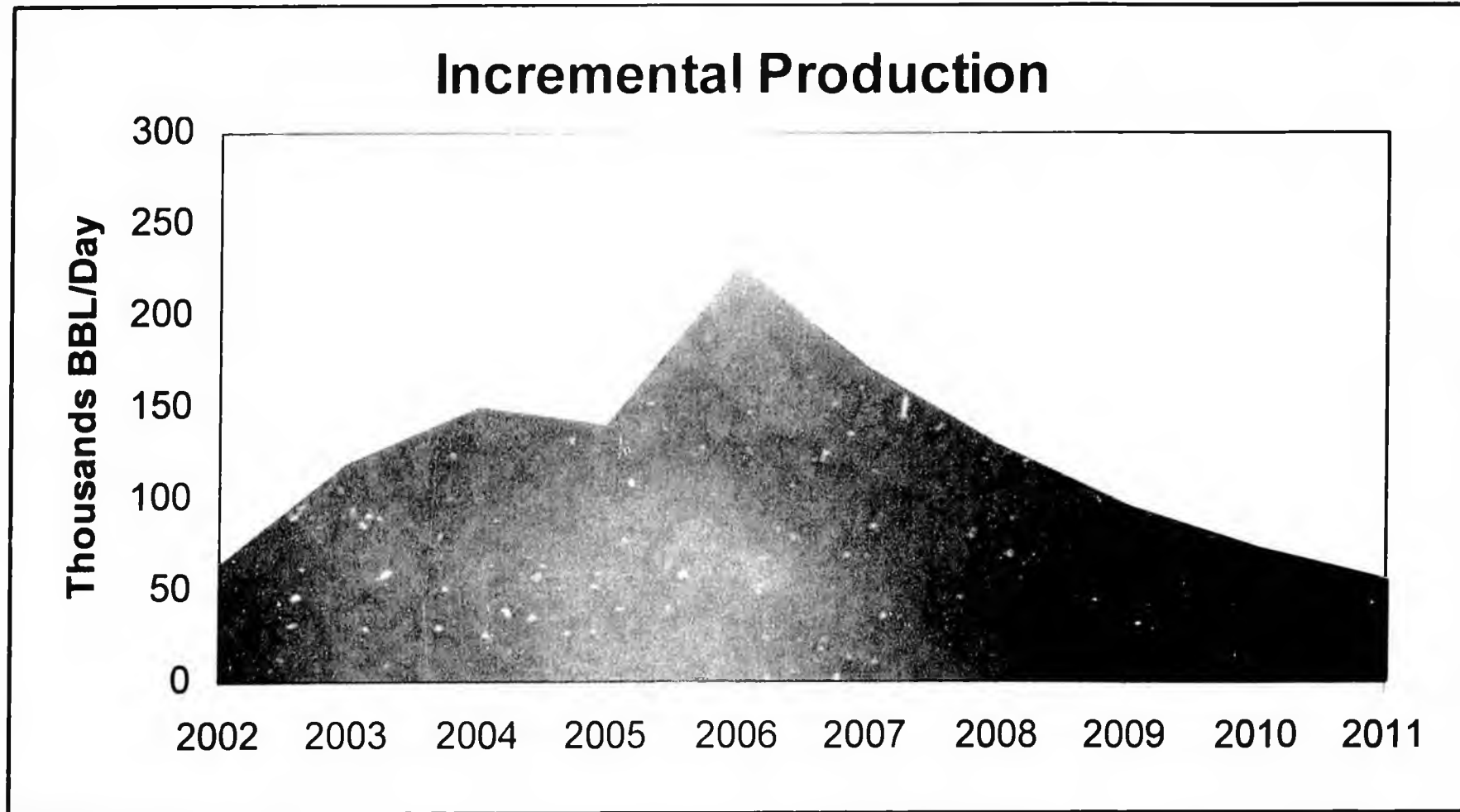
5 Year Prudhoe Drilling Program

- Drilling capex – 300% for added facilities/injection





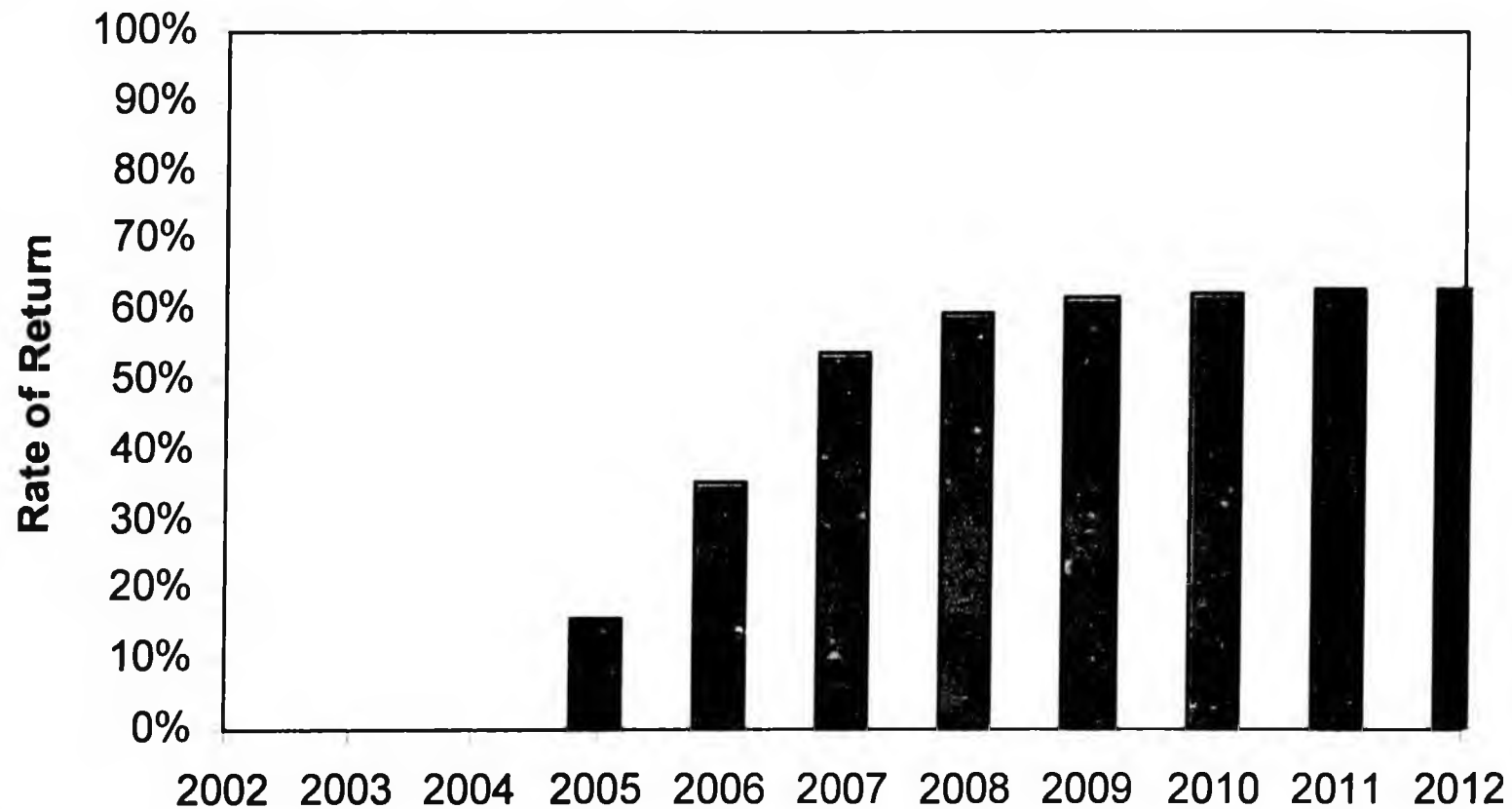
BP – Prudhoe Bay



BP Prudhoe Bay

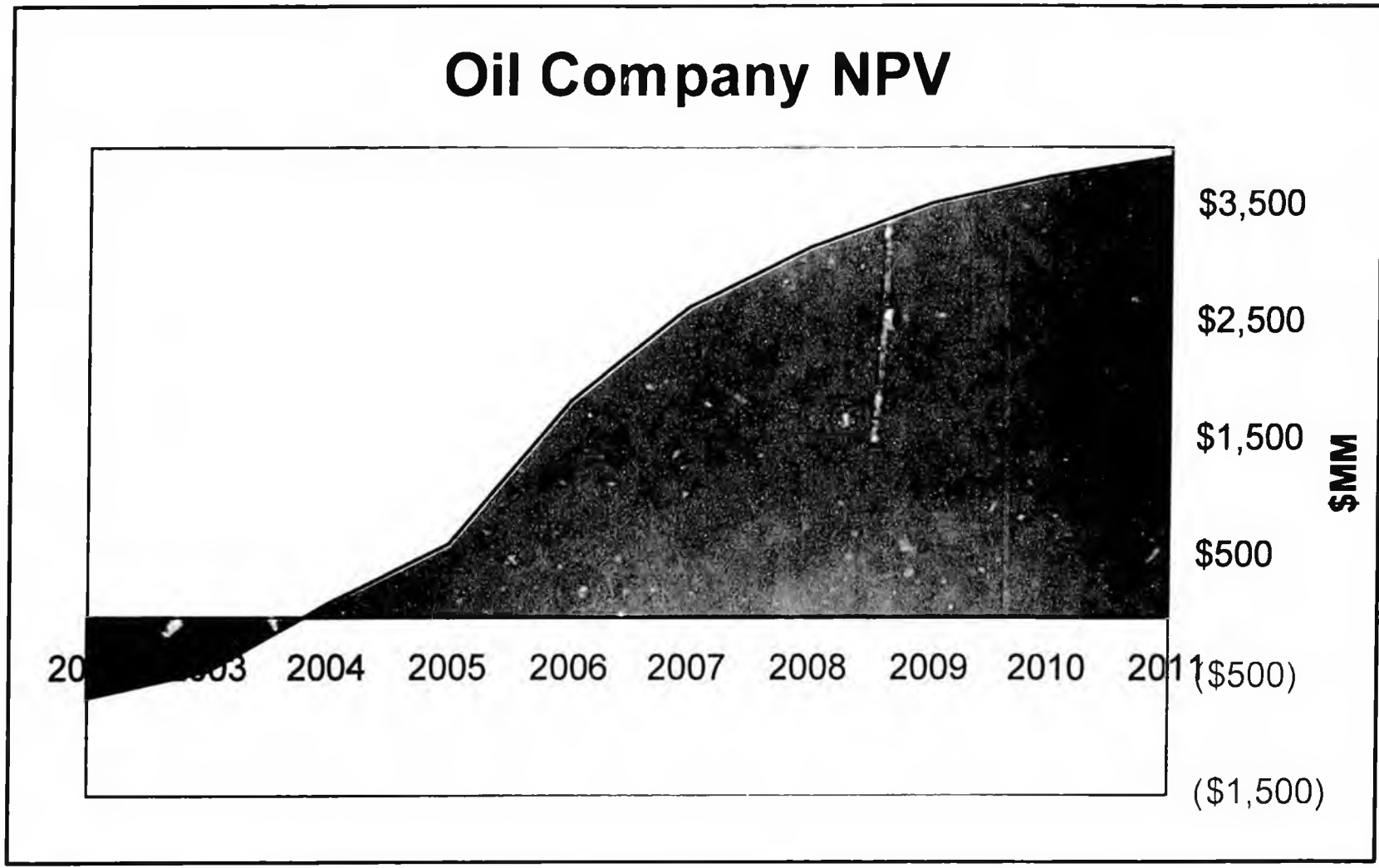


Oil Company After Tax IRR



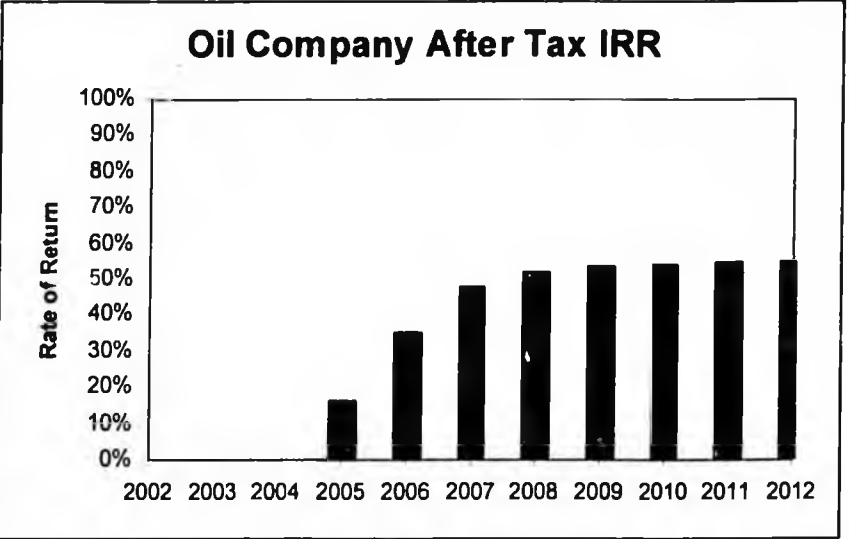
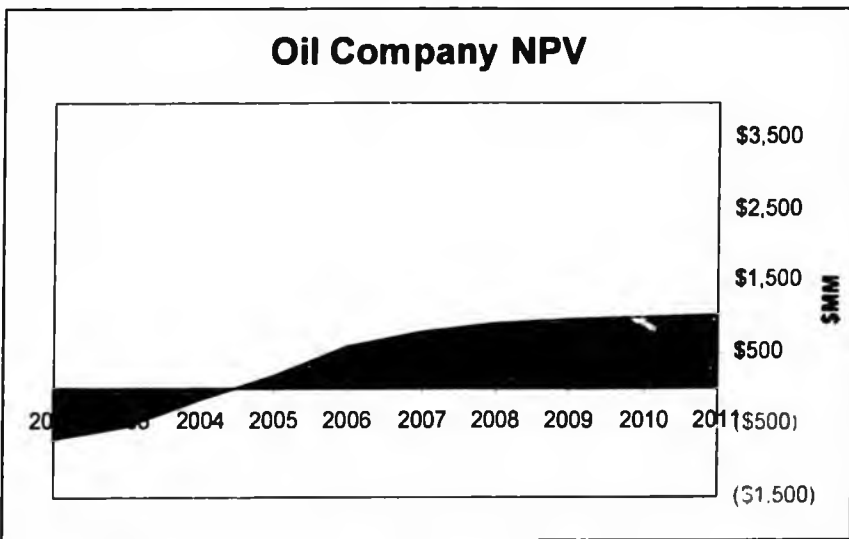
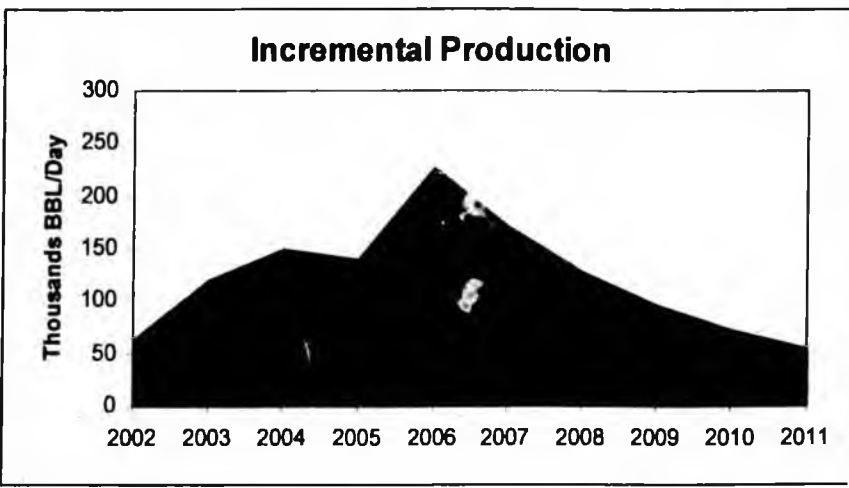
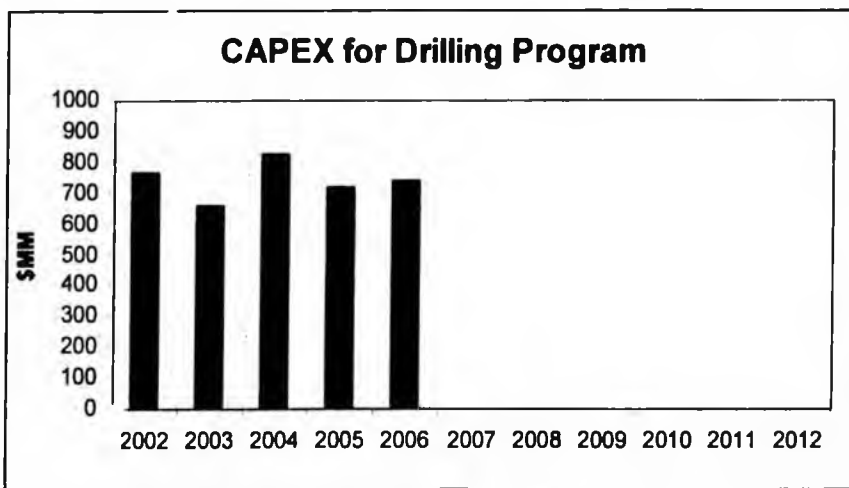


BP Prudhoe Bay





Overly Stressed Case



Model





North Slope Potential

Production Drives Revenue



Decline Rate	15%	6%	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	\$5 bn	\$25 bn	\$70 bn
		Status quo	

- **Built a generic model based on the above barrels and investments**
 - Used indicated decline rates
 - 250,000 bpd abandonment rate

Under PPT



Production Drives Revenue



Decline Rate	15%	6%	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	\$5 bn	\$25 bn	\$70 bn
		Status quo	

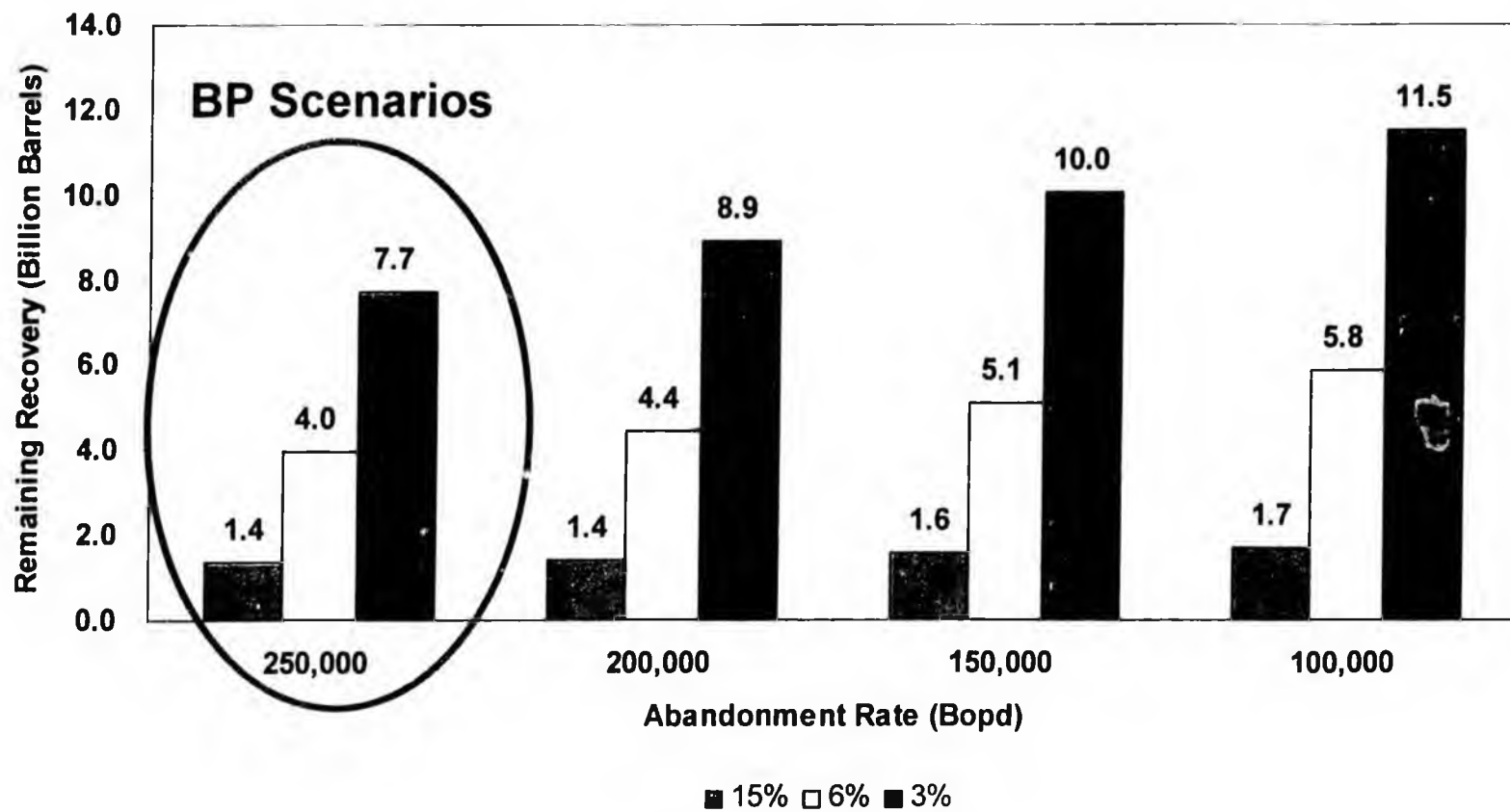
- | | | | |
|-----------------|---------------|---------------|----------------|
| • NPV10 = \$Bn | • \$15 - \$20 | • \$30 - \$40 | • \$35 - \$45 |
| • NPV0 = \$Bn | • \$22 - \$27 | • \$55 - \$75 | • \$90 - \$125 |
| • NPV0 = \$/bbl | • \$15 - \$20 | • \$14 - \$19 | • \$12 - \$17 |

~ \$80/bbl WTI, \$70/bbl NS



North Slope Abandonment

Impact Of Abandonment Rate On North Slope Recovery





Summary

- **Oil Company must show “reasonable certainty” about future spending to be able to book reserves**
 - There is pressure in the market place to declare ‘proved reserves’ as soon as feasible -- important to shareholder and analyst growth expectations
 - If the production volumes associated with the 6% and 3% decline scenarios have already been booked as proved reserves, then to **not** undertake the continuing investments would require a significant write down of reserves
- **Drilling program is so profitable that under even the most extreme net tax structure, oil companies would want to continue their reinvestment program.**

Goals



Goals for Fiscal Design

- **Based on hearings, discussions and other dialog we see the following as the goals you are trying to achieve in this special session:**
 - Fields with larger **profitability** should be paying more taxes
 - Encourage investment in existing units
 - Reinvestment in producing assets
 - Investment in new developments
 - ❖ Conventional
 - ❖ Unconventional (i.e. heavy oil)
 - Encourage new investment outside legacy units
 - Level playing field for incumbents and new entrants
 - Durability
 - Don't want to be back 'fixing' things
 - Build on prior tax dialogue



Encourage New Investment

- **Fiscal system should encourage investment in new fields**
 - Investment credits
 - Net Operating Loss credits
 - Aid to new entrants with no existing tax base
 - Lower tax rate for fields with higher cost structure
 - More distant from infrastructure
 - Heavy Oil
 - Gas
- **Is base rate low enough?**
 - Additional barrels down TAPS extends production from existing reservoirs



The Fiscal Design Challenge

- **The Take**

- Fair share of the high margins currently being realized
- Progressive structure to adapt to changes in:
 - Price
 - Production
 - Cost

- **The Give Back**

- Encouragement to reinvest profits for more development inside legacy units

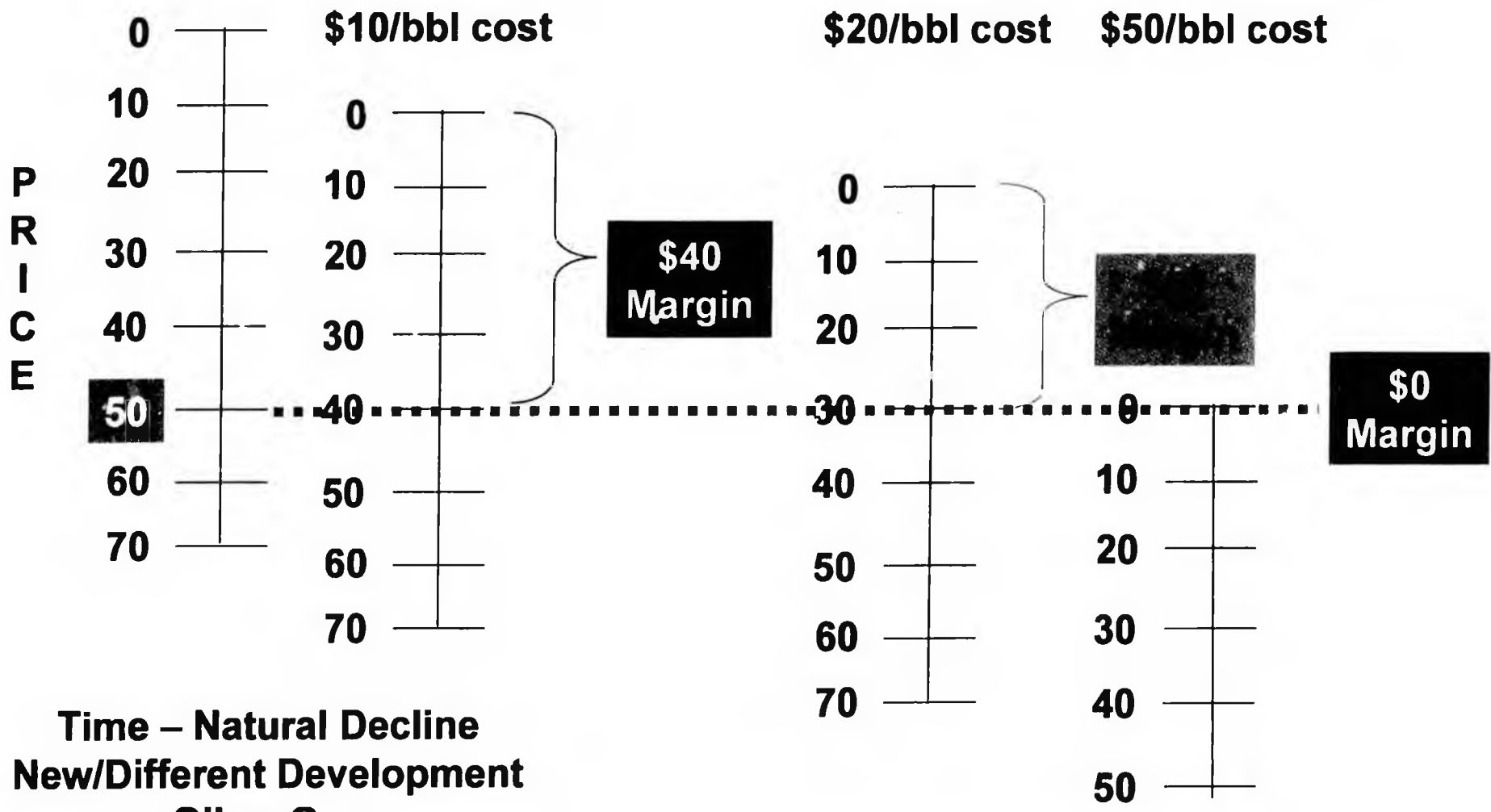


Key Point Easily Misunderstood

Price \neq Margin

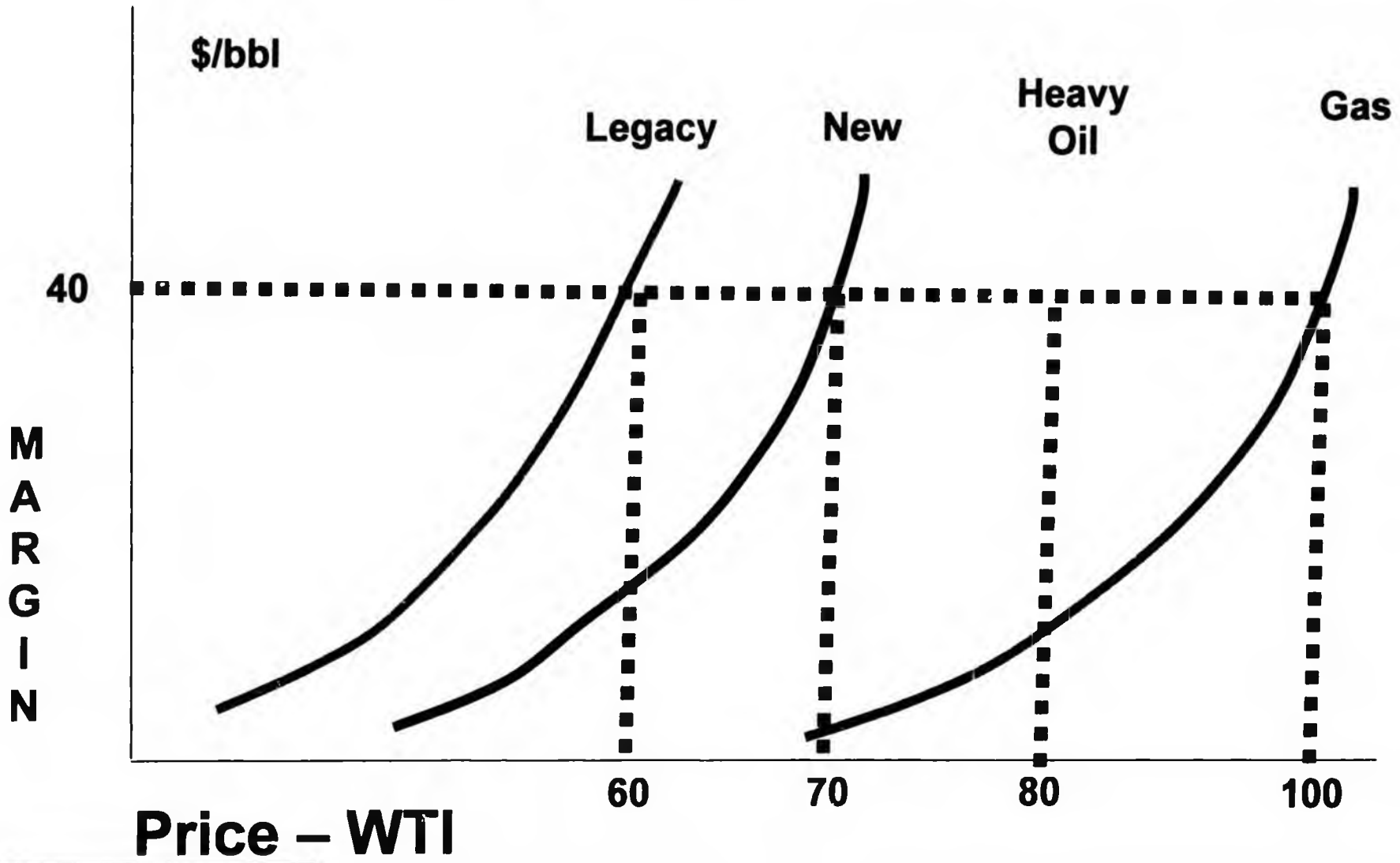


Price versus Margin



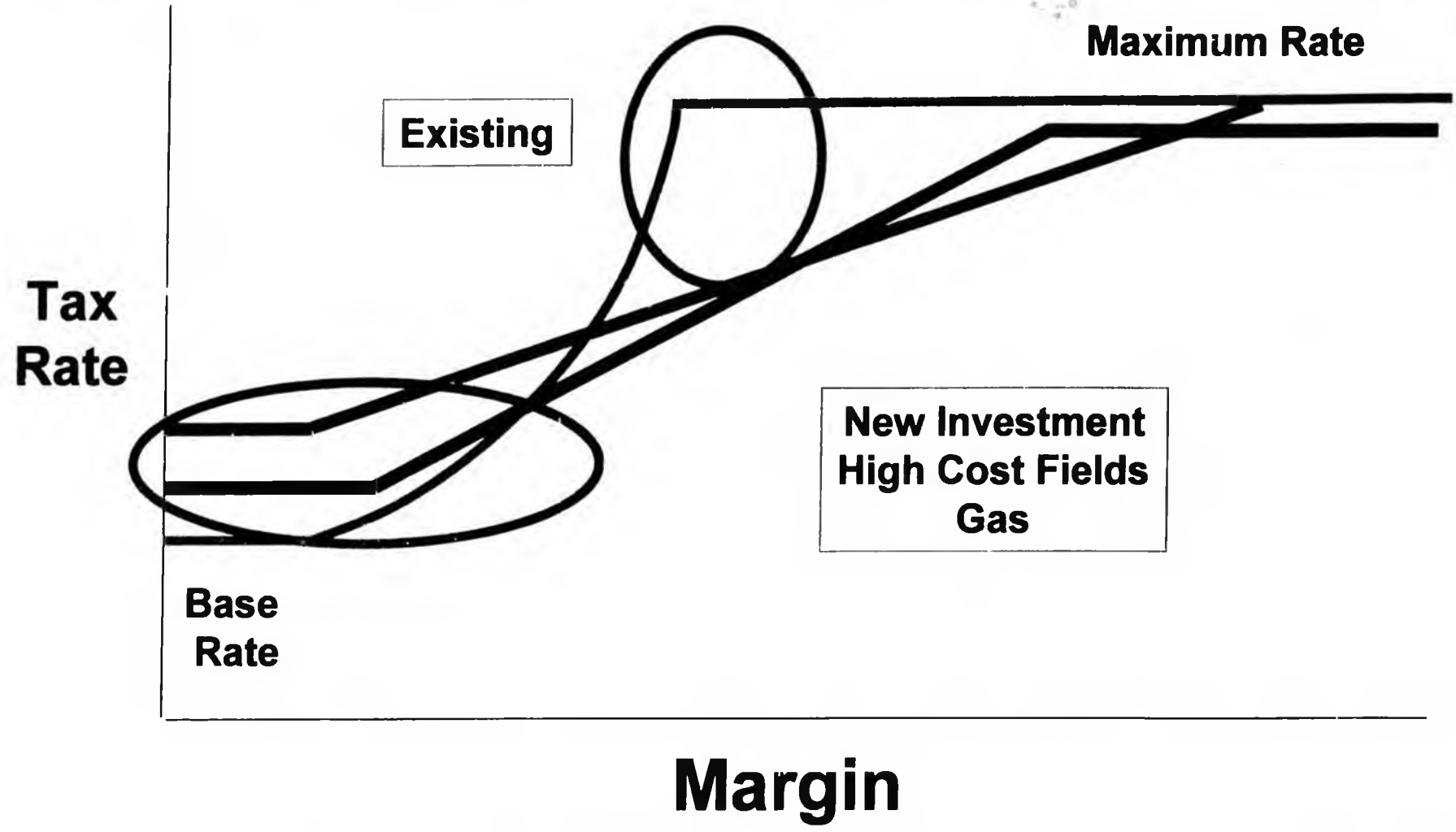


Margin versus Price





Pulled Into a single mechanism

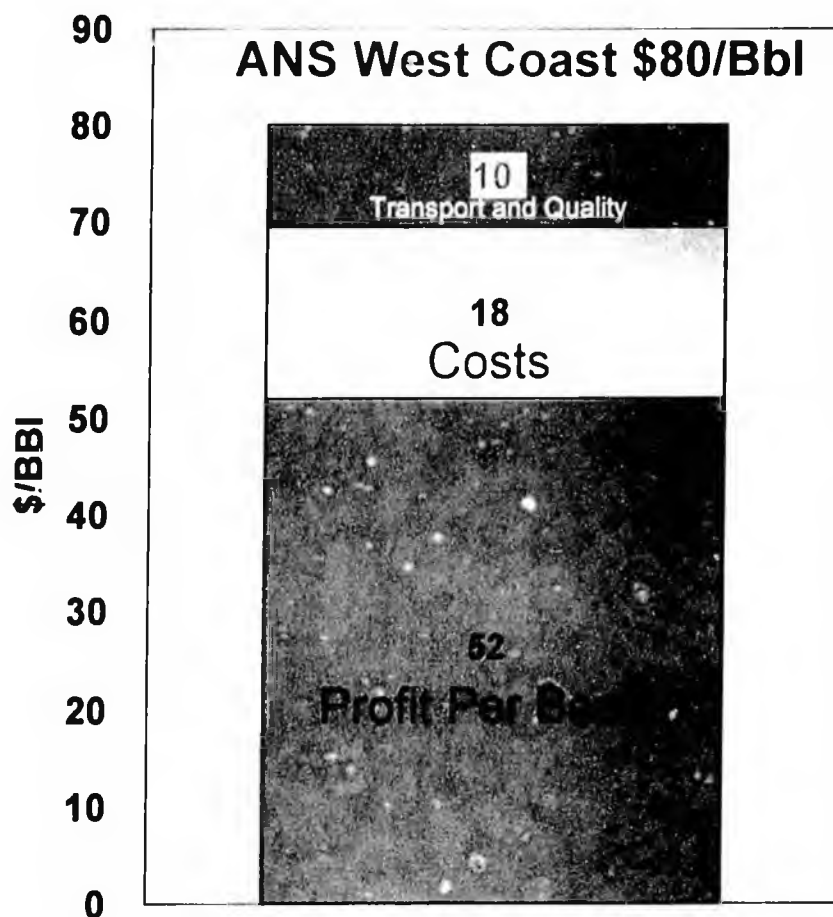


The Net Tax Story



The Information Used

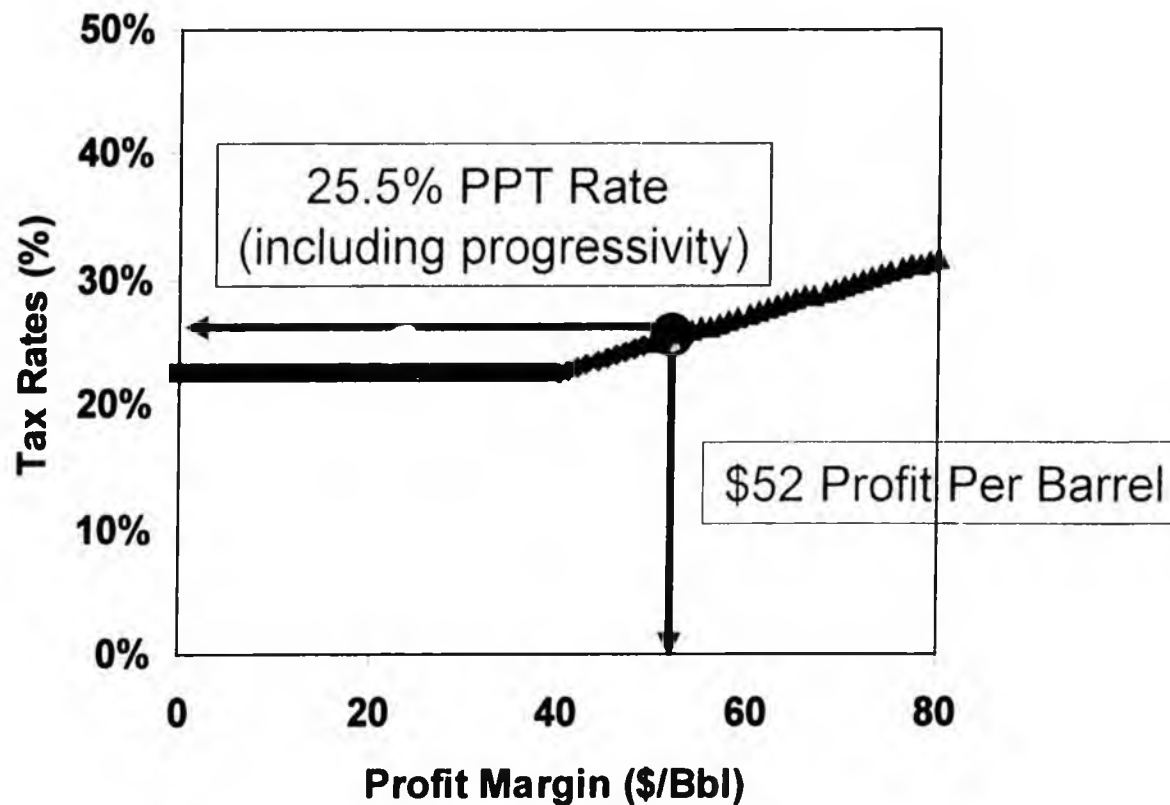
Portfolio Profitability





Based On \$52/Bbl Profit ...

Tax Rate Structure (Incorporating Progressivity)





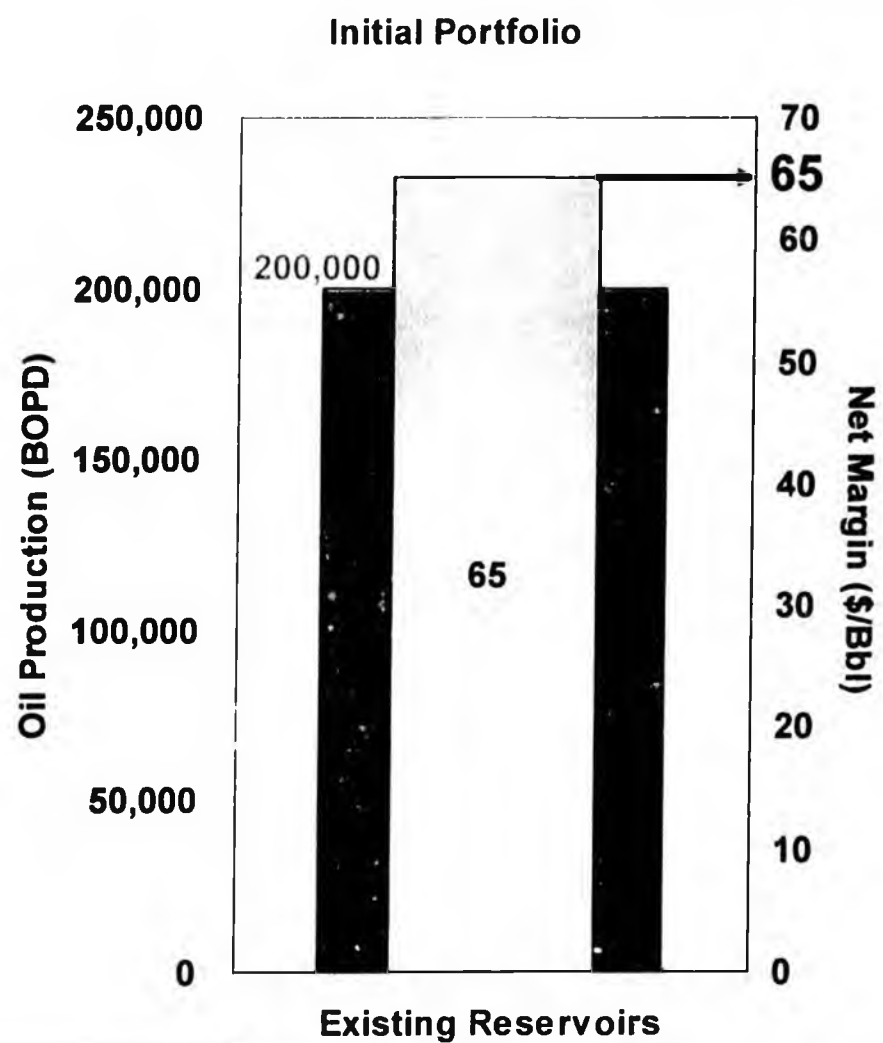
Progressivity

- **“Net” taxes all fields at a single rate**
 - No, it taxes different fields or reservoirs based on their individual profitability

Understanding The Rate Structure



Start With A Portfolio Of One Investment

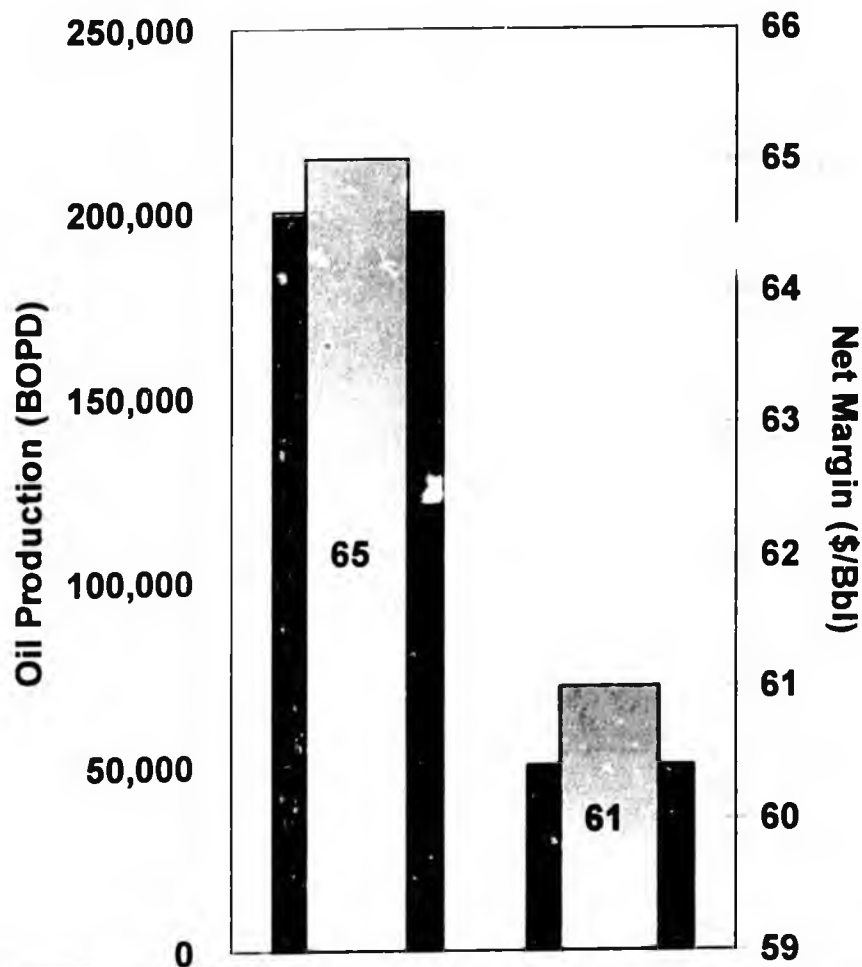


PPT Rate on this would be
28.4%



Now, Add Another Field

Expanded Portfolio



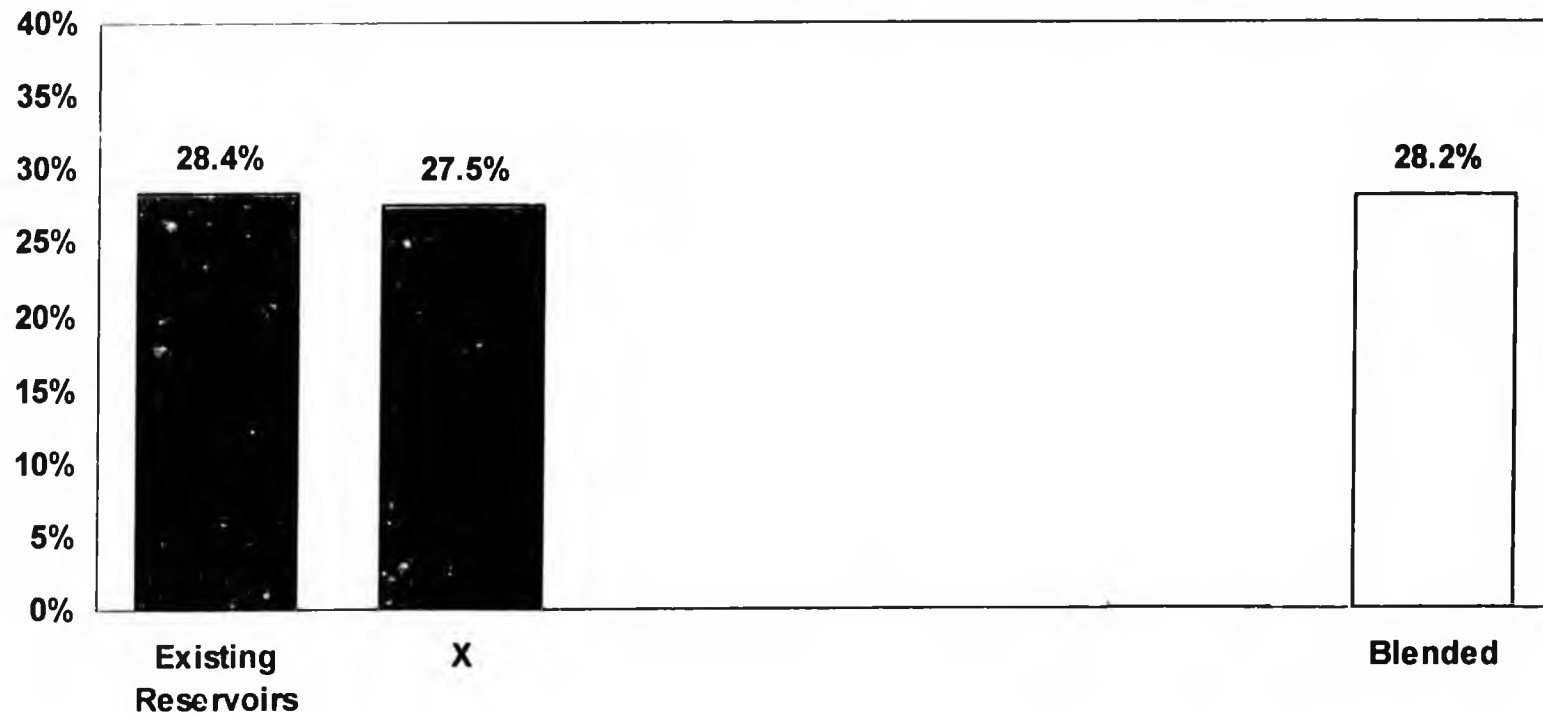
**PPT Rate on these fields
Combined would be
28.2%**

**Average Net Margin Is
\$64.20**

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



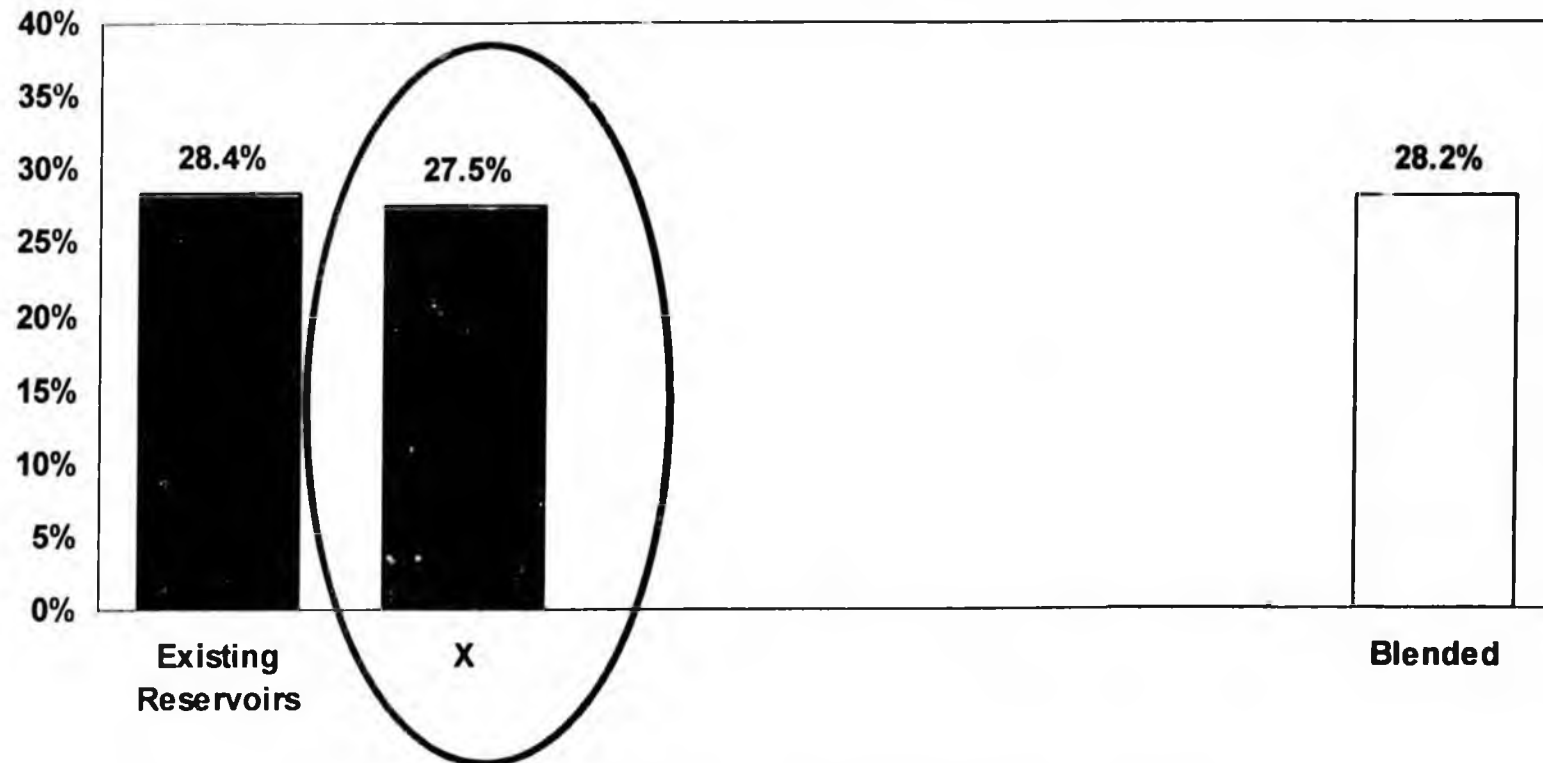
No

Look at this in the way that companies look at it when they make investment decisions

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

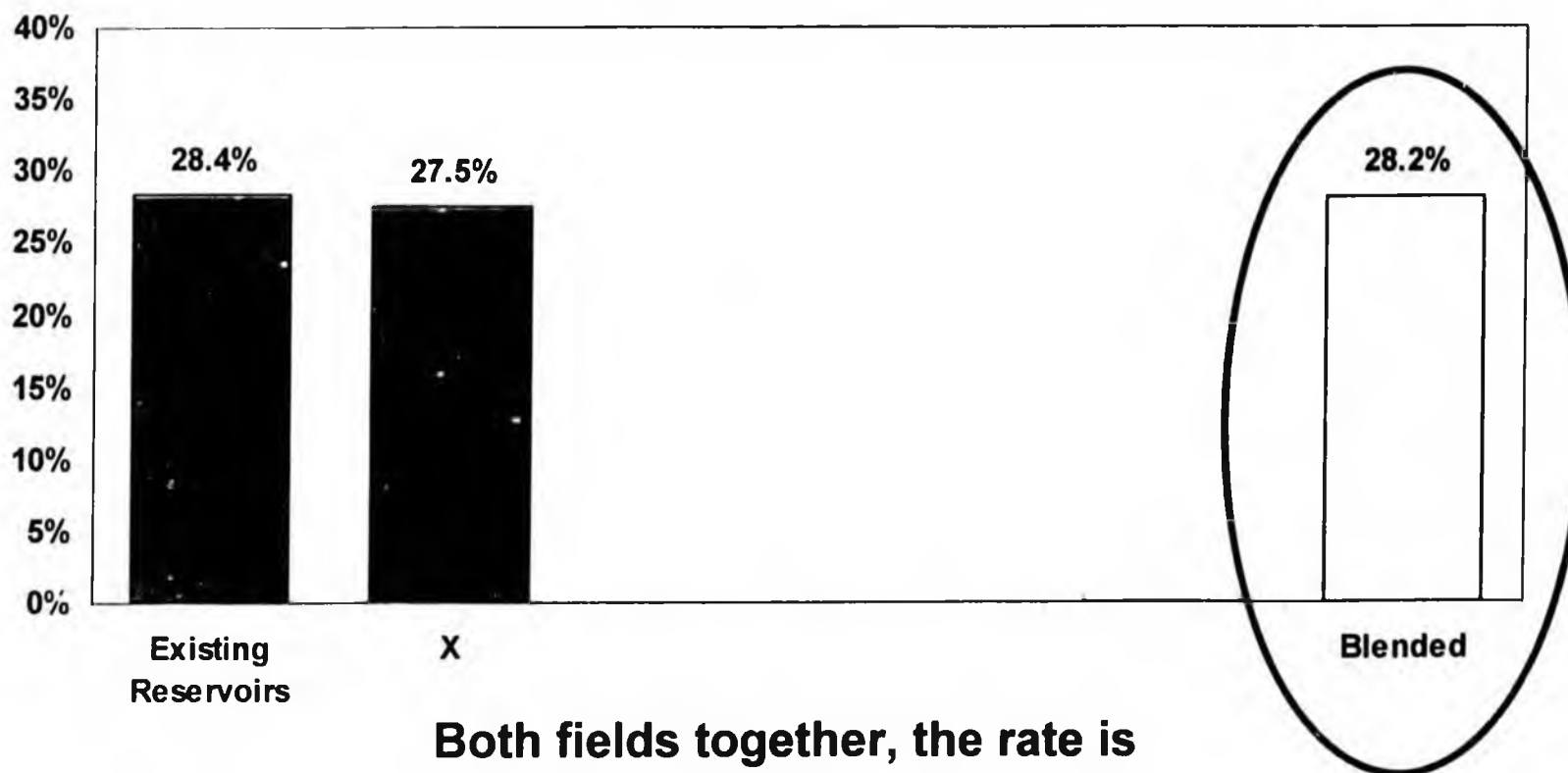


If I had just Field X, I would pay tax on my profits at 27.5% - its margin is slightly lower

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



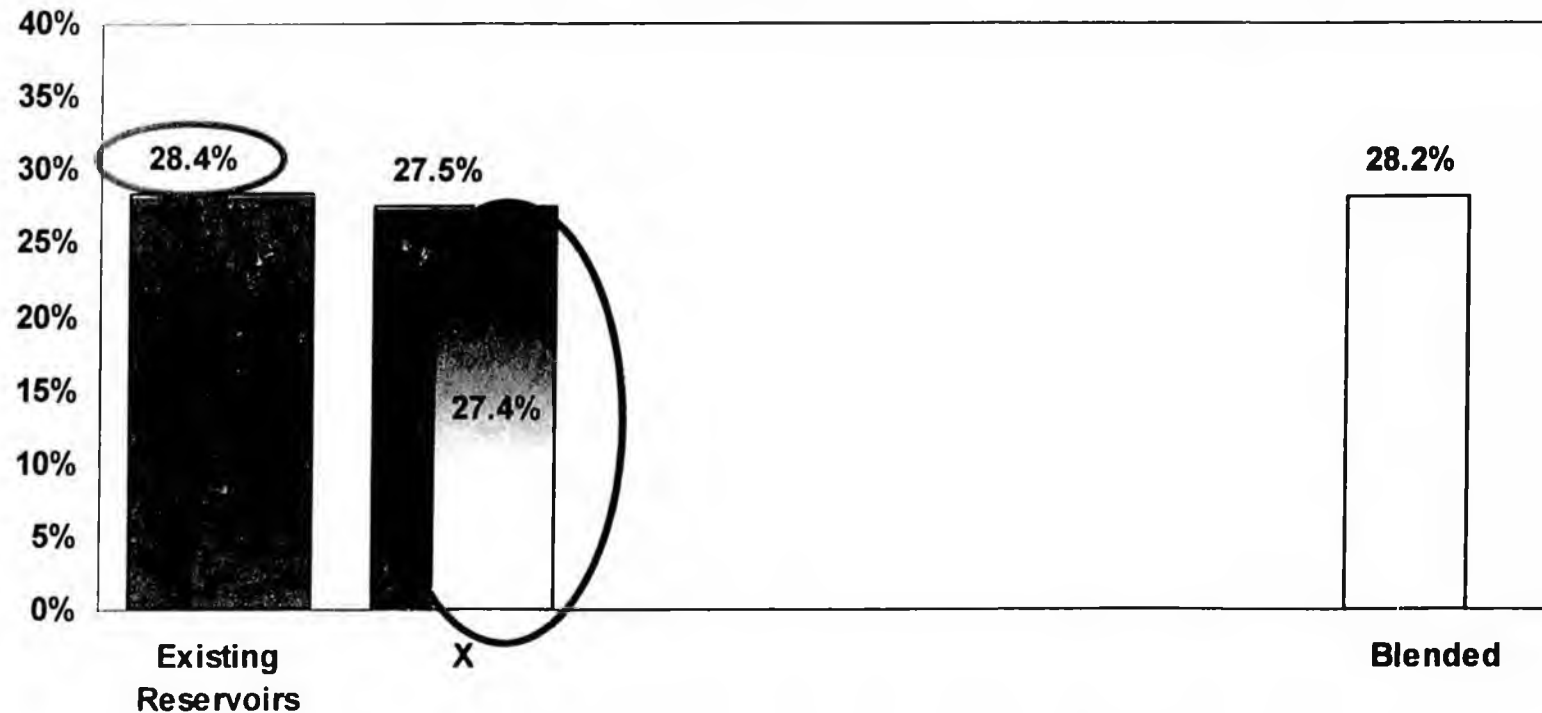
Both fields together, the rate is
28.2%

However, this is not all ...

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

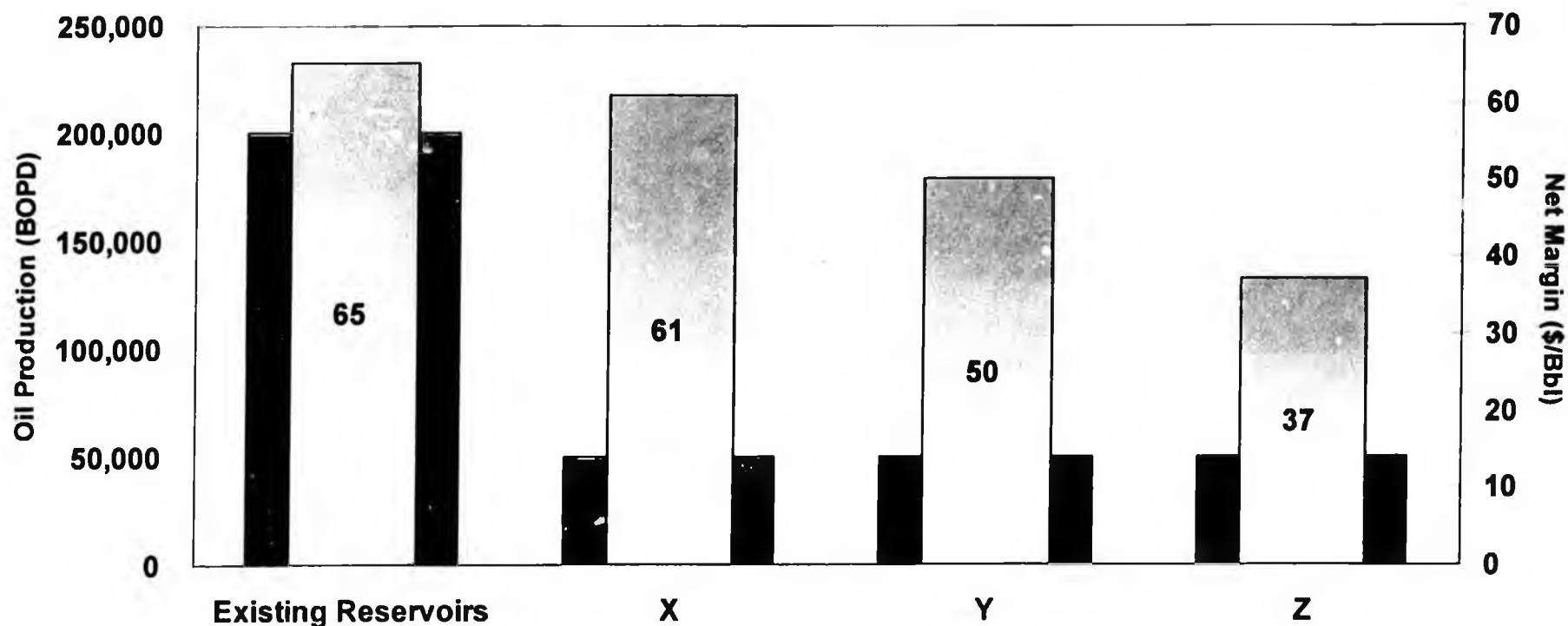


The mathematics of this reduction means that actually while Existing Reservoirs continue to pay tax at a rate of 28.4%,
The effective rate on Field X is actually 27.4%
... less than it would be if it were developed stand-alone

This Impact Can Be Seen In A Broader Portfolio



Portfolio Production Rate and Net Margin

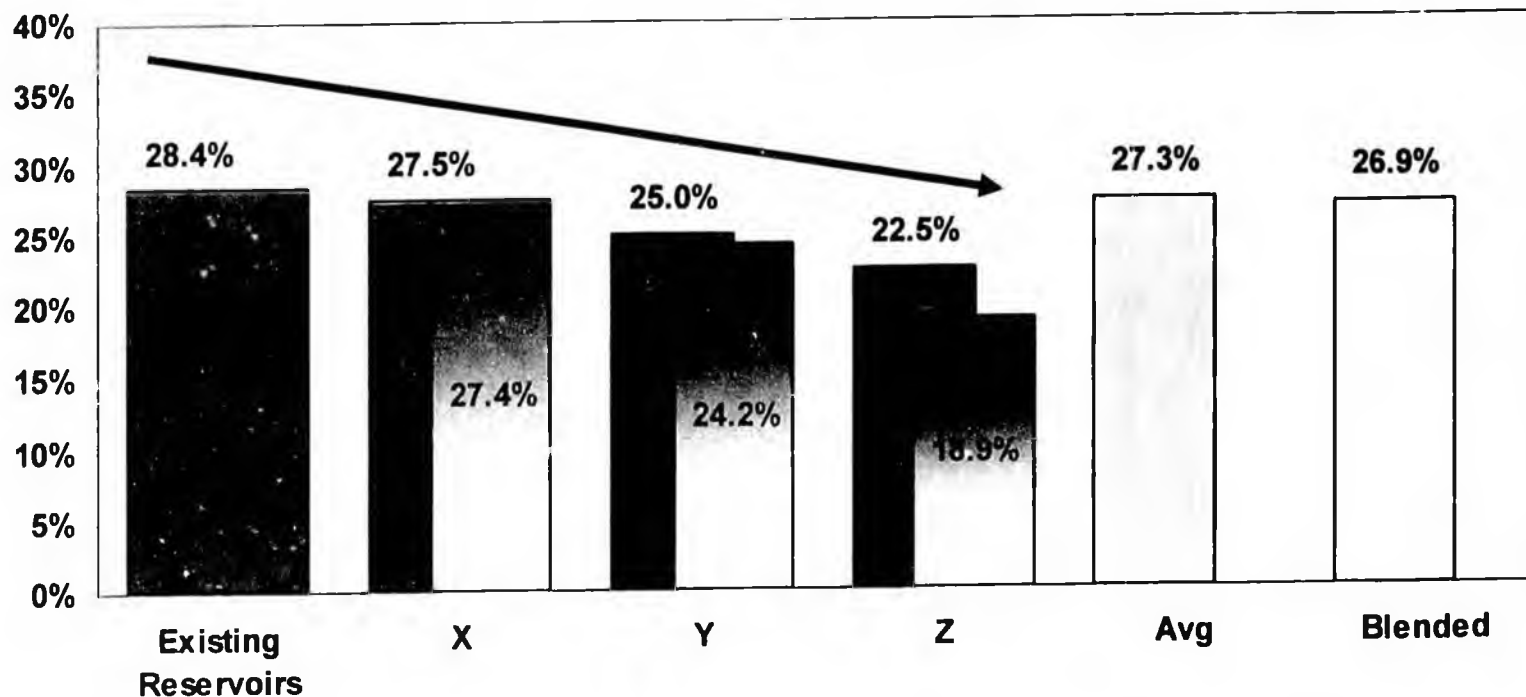


In this example we have four fields ...
.. One producing 200,000 bopd and
three others each producing 50,000 bopd but of decreasing profitability

The Impact On The Lower Margin Fields Is More Noticeable



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

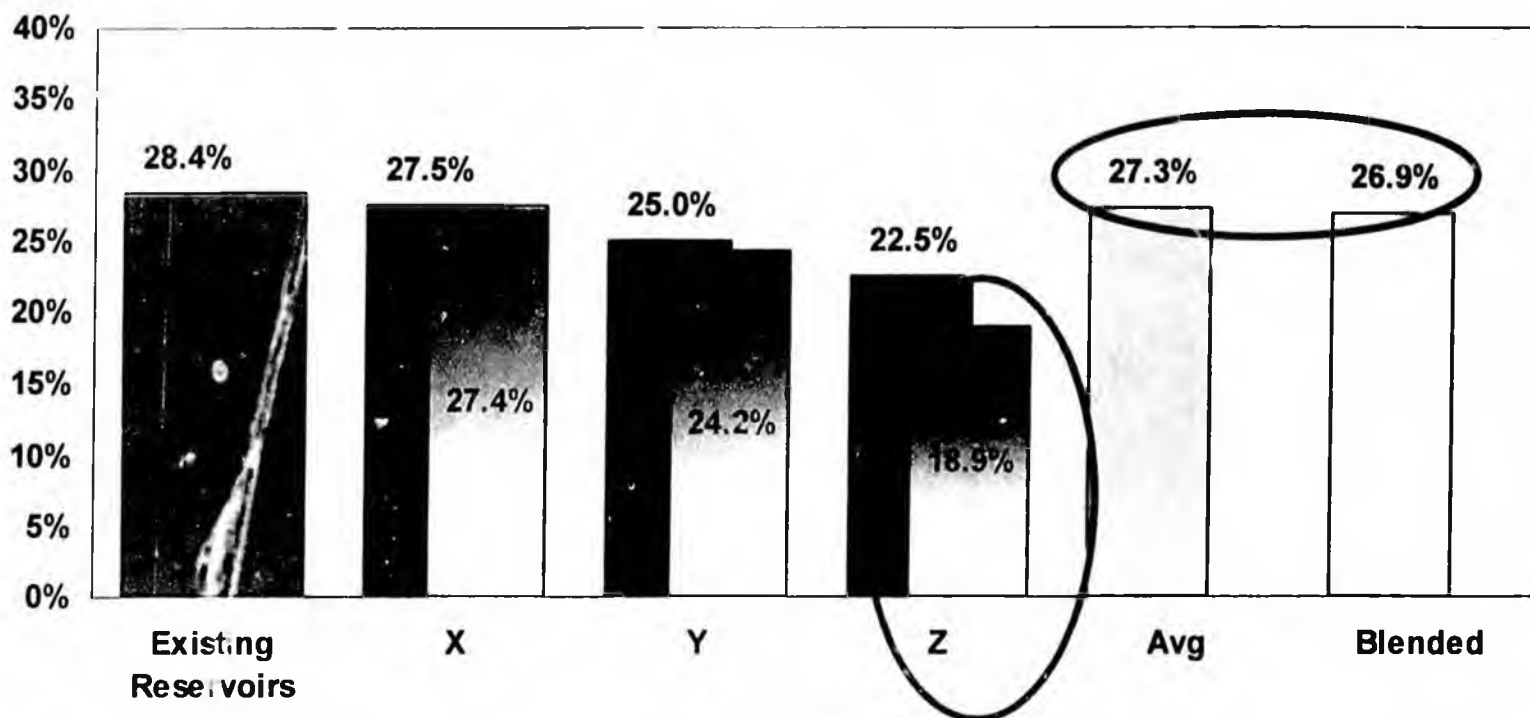


The progressivity can be seen through the lower effective tax rate on lower margin fields

The Impact On The Lower Margin Fields Is More Noticeable



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



The effective rate on some lower-margin fields may even be lower than the basic rate (22.5% in PPT)

This is manifested in the blended rate being lower than the weighted average rate

The Impact Of Capital Investment



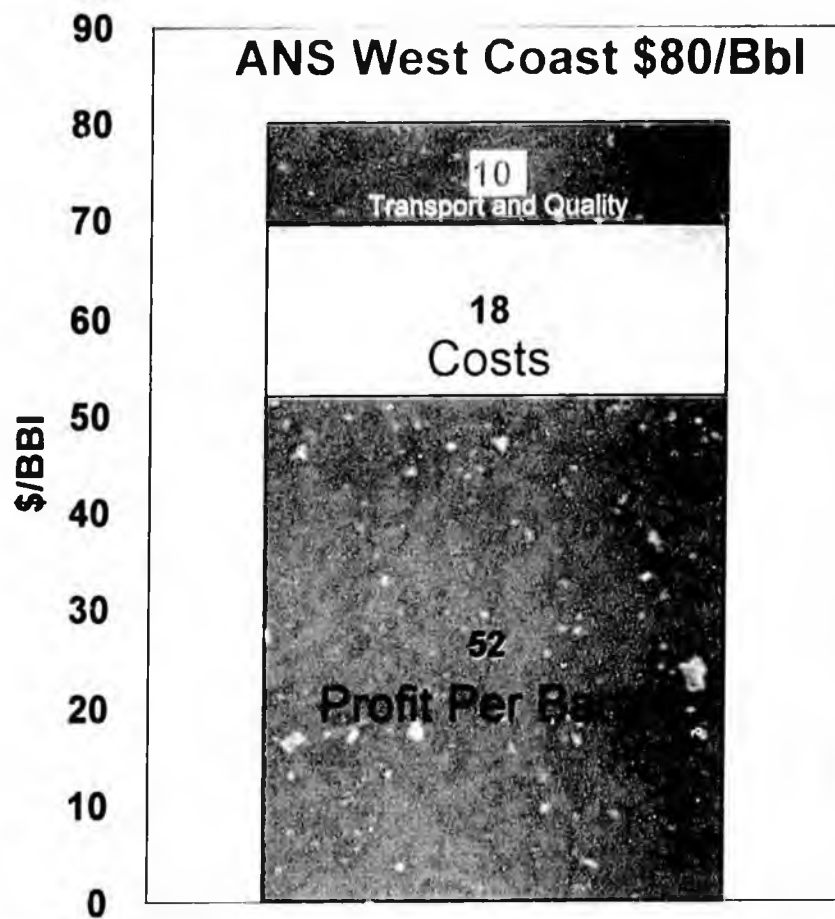
Cash Flow, Not Profit

- PPT taxes all fields at a single rate
 - No, it taxes different fields or reservoirs based on their individual profitability
- **Is based on profit per barrel**
 - Not exactly, it is based on net cash flow per barrel after capital investment (for future production)



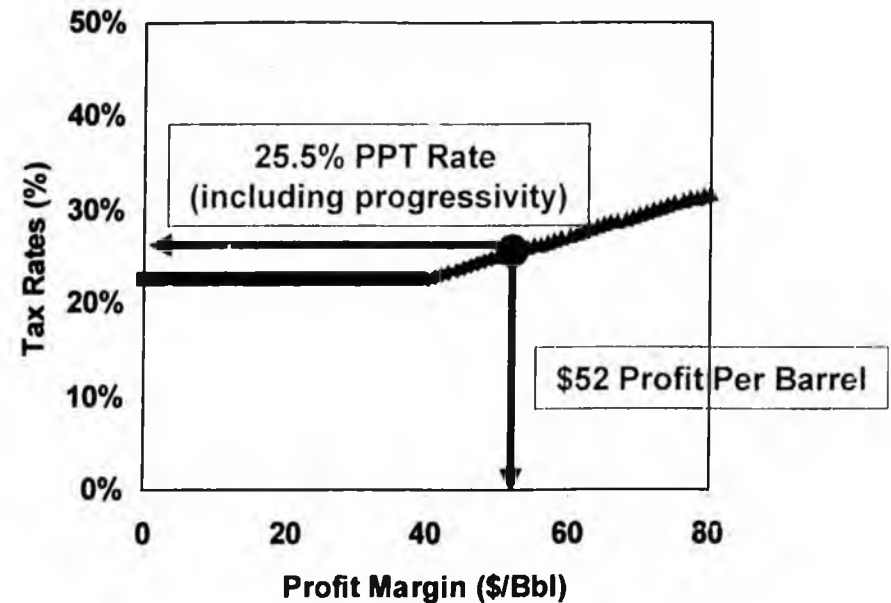
Remember These Slides ?

Portfolio Profitability



The portfolio on the previous slides had a blended rate of **26.9%**, not **25.5%**

Tax Rate Structure (Incorporating Progressivity)



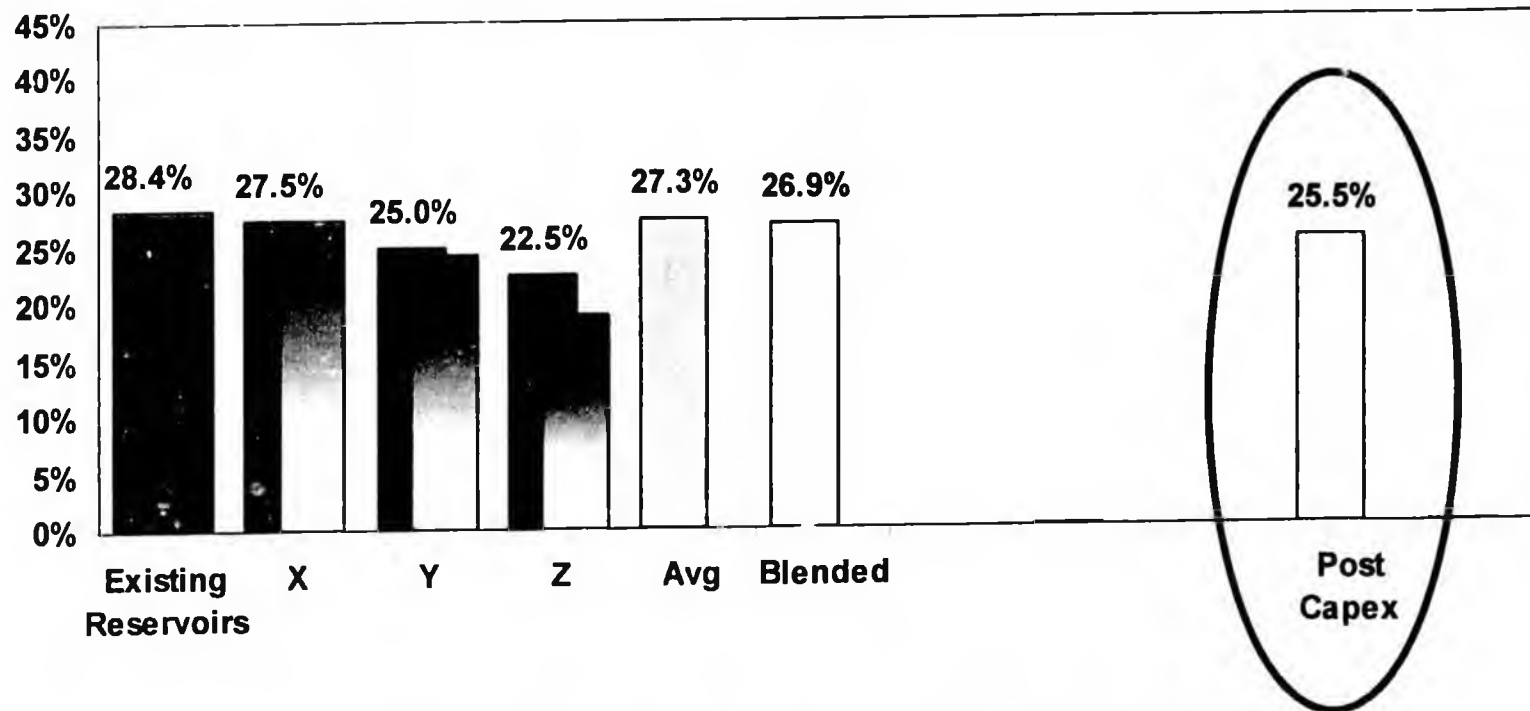
**Assume that 26.9% is the rate that will
be payable before further capital
investment decisions are made ...**

... in this example \$800 million

Capital Spending Has An Impact On Rate, Too



Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



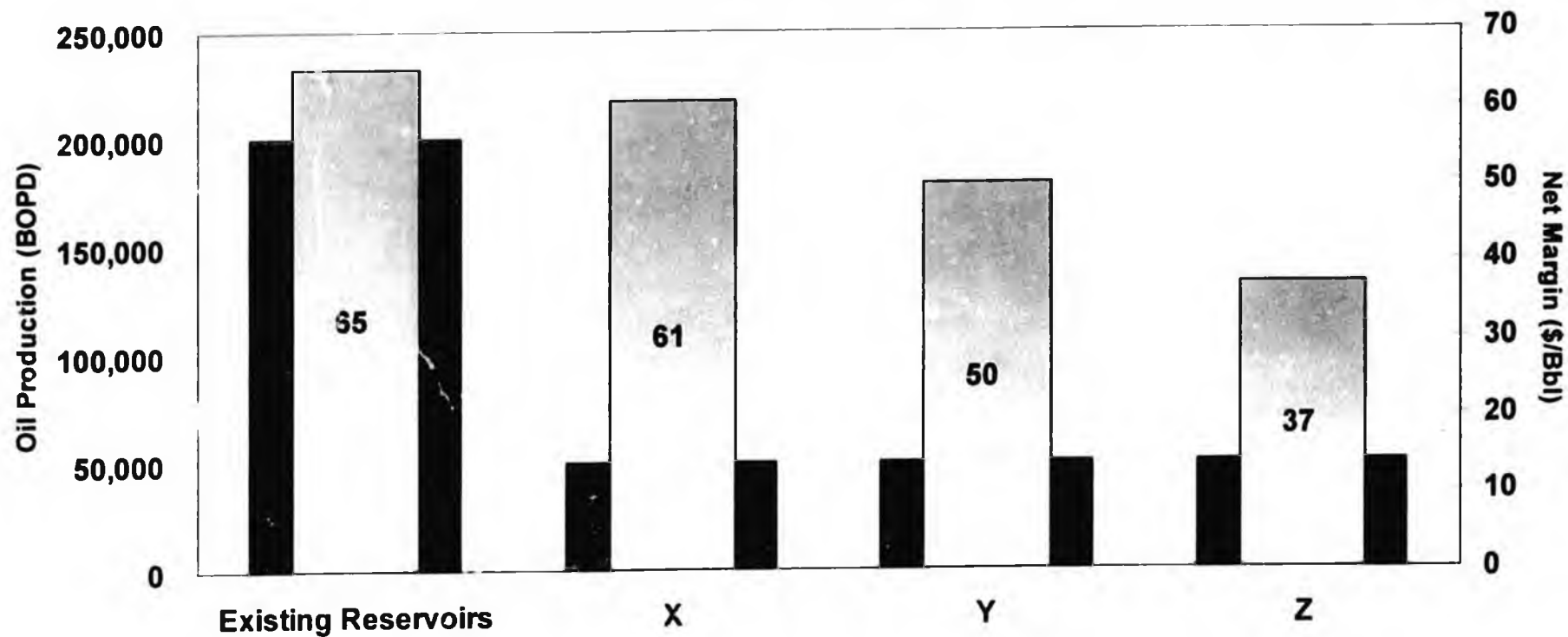
This reduces the rate payable to 25.5%

How ?

\$800 million amounts to \$6.26 Per Barrel Based On This Portfolio



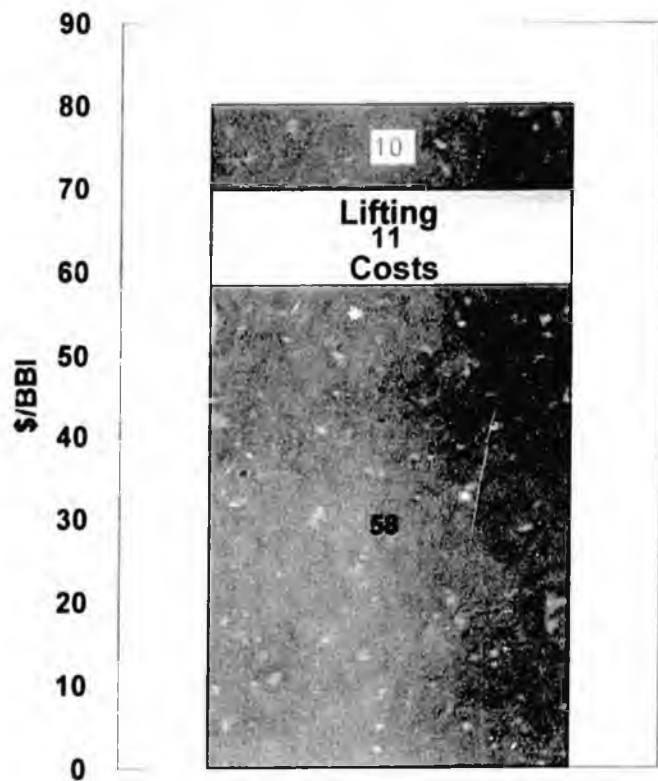
Portfolio Production Rate and Net Margin





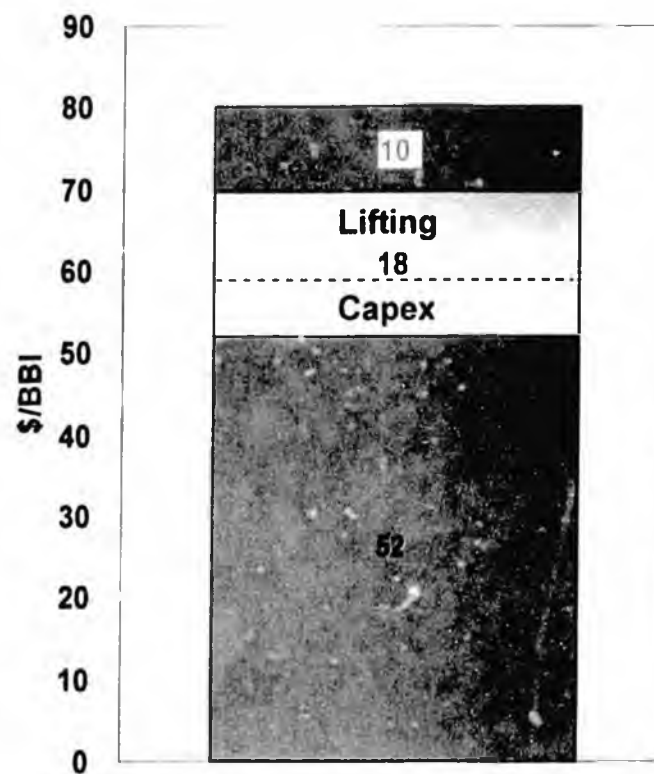
The \$6.26 Per Barrel Capital Increases "Costs" And Lowers The Tax Rate

Pre-Capex Margin



Tax Rate
26.9%

Portfolio Profitability

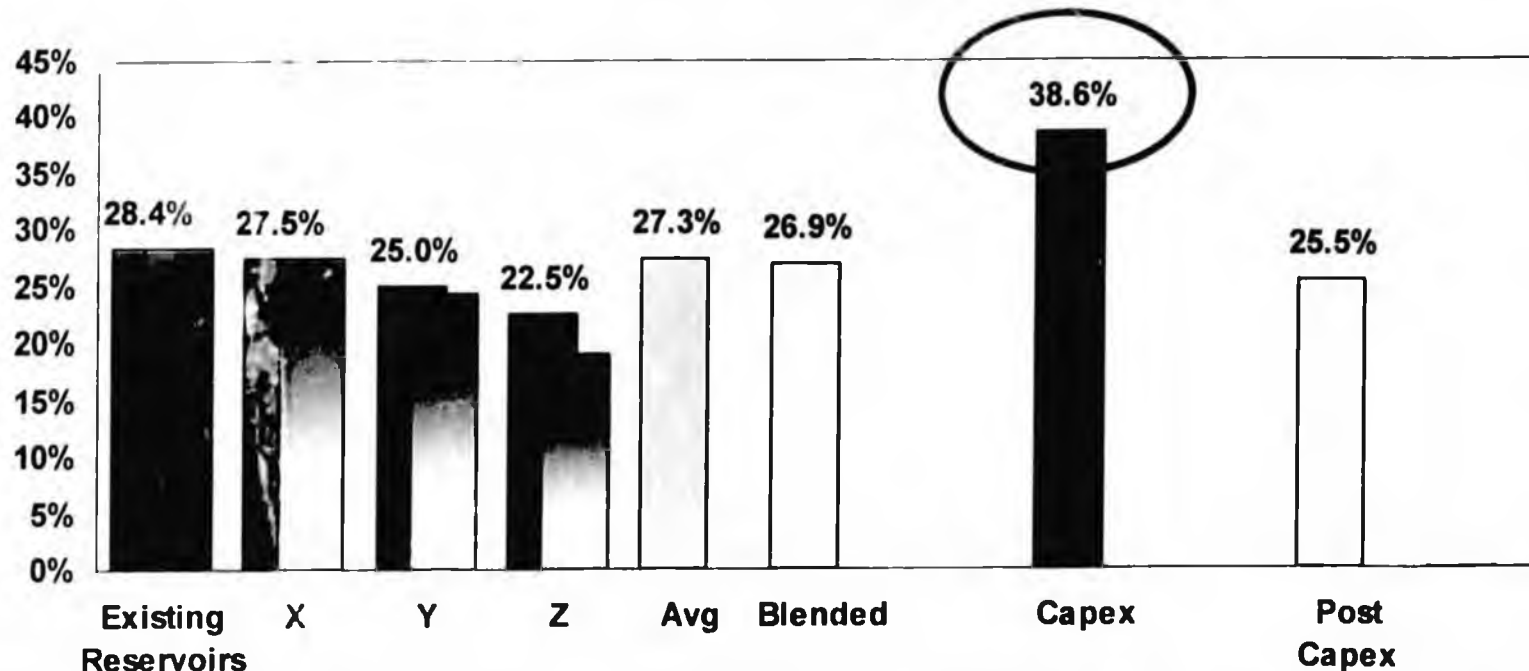


Tax Rate
25.5%



There Is Another Way To Look At This, Though

Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



It is the same as still paying the blended rate of 26.9% on the portfolio production (or having an effective rate of 28.4% on Existing Reservoirs .. down to 18.9% on Field Z) and Alaska paying* 38.6% of that \$800 million capital

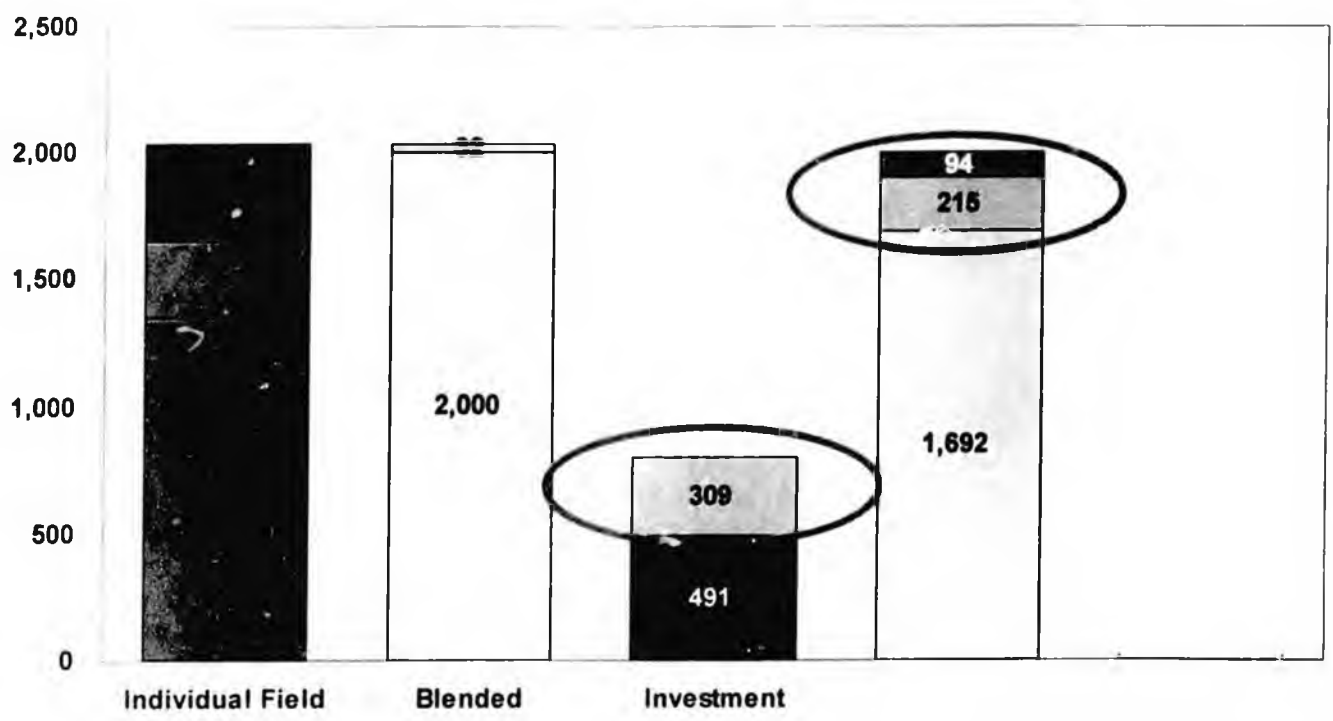
This 38.6% is higher than the Blended tax rate ... and is a function of the capex per barrel and the overall portfolio cost and margin structure

* from PPT only - does not include State and Federal tax effects



The Big Winner Though Is Capex

Tax Allocable By Field Within Portfolio

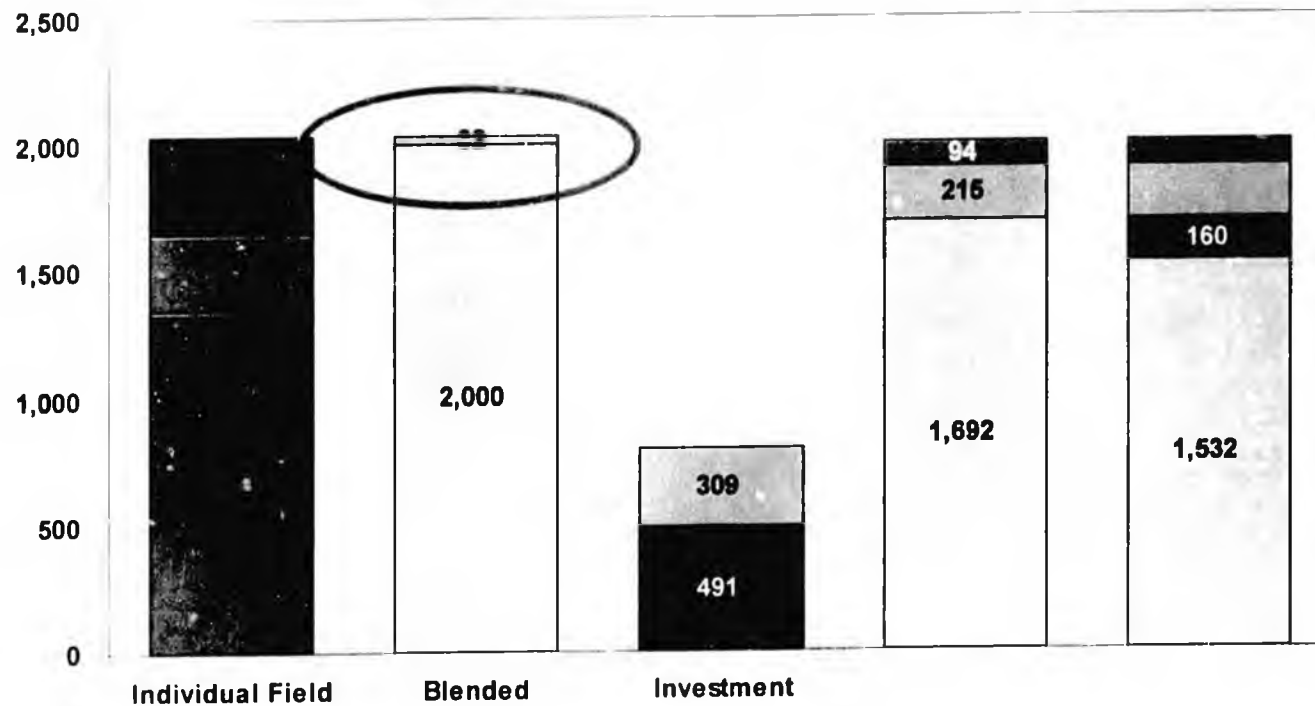


In this example the State pays \$309 million (38.6%) of the capital (the percentage will vary based on overall portfolio net margin per barrel)
The \$309 million can be allocated as \$215 million from reducing taxable income at 26.9% and \$94 million from lowering the rate from 26.9% to 25.5%



But Wait! That Is Not All

Tax Allocable By Field Within Portfolio

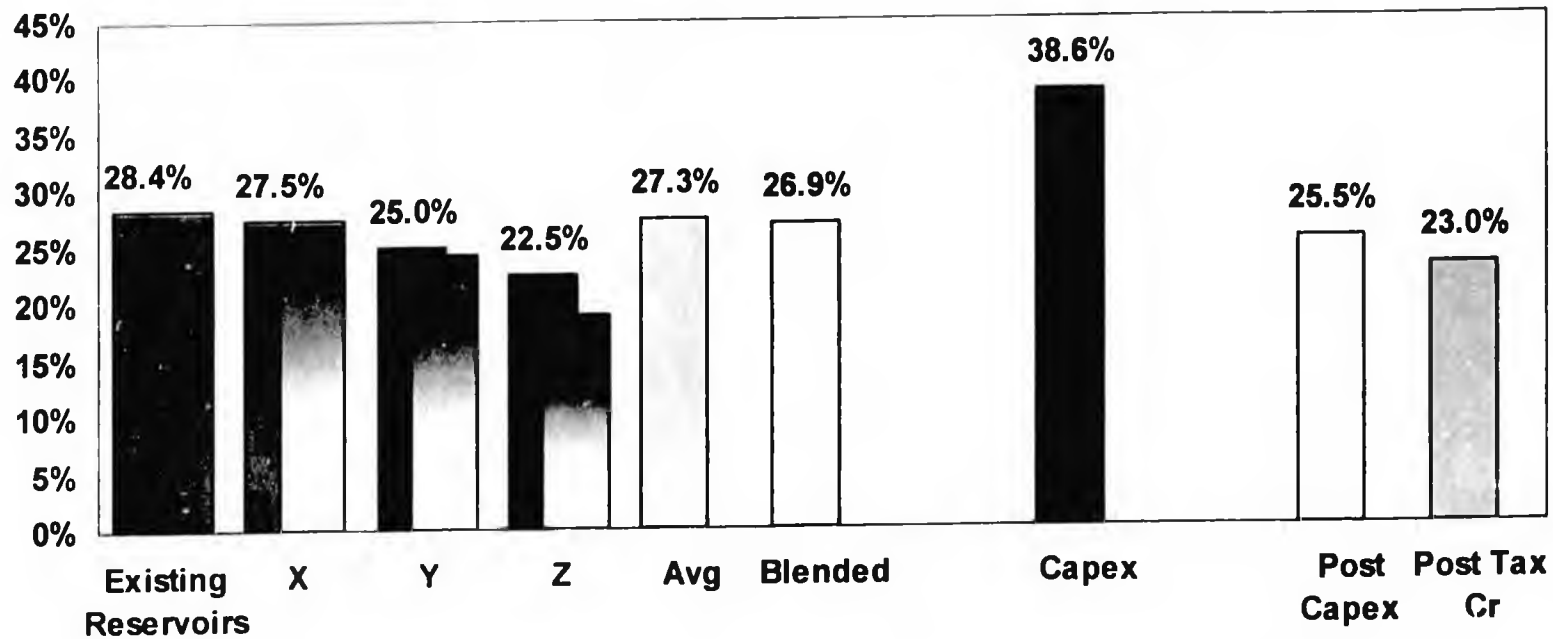


Investment Credits Take a further \$160 million (20% of \$800 million) from the tax payable



After Investment Credits ...

Tax Rate By Field Within A Company - As Affected By Portfolio Blending,
Capex And Tax Credit



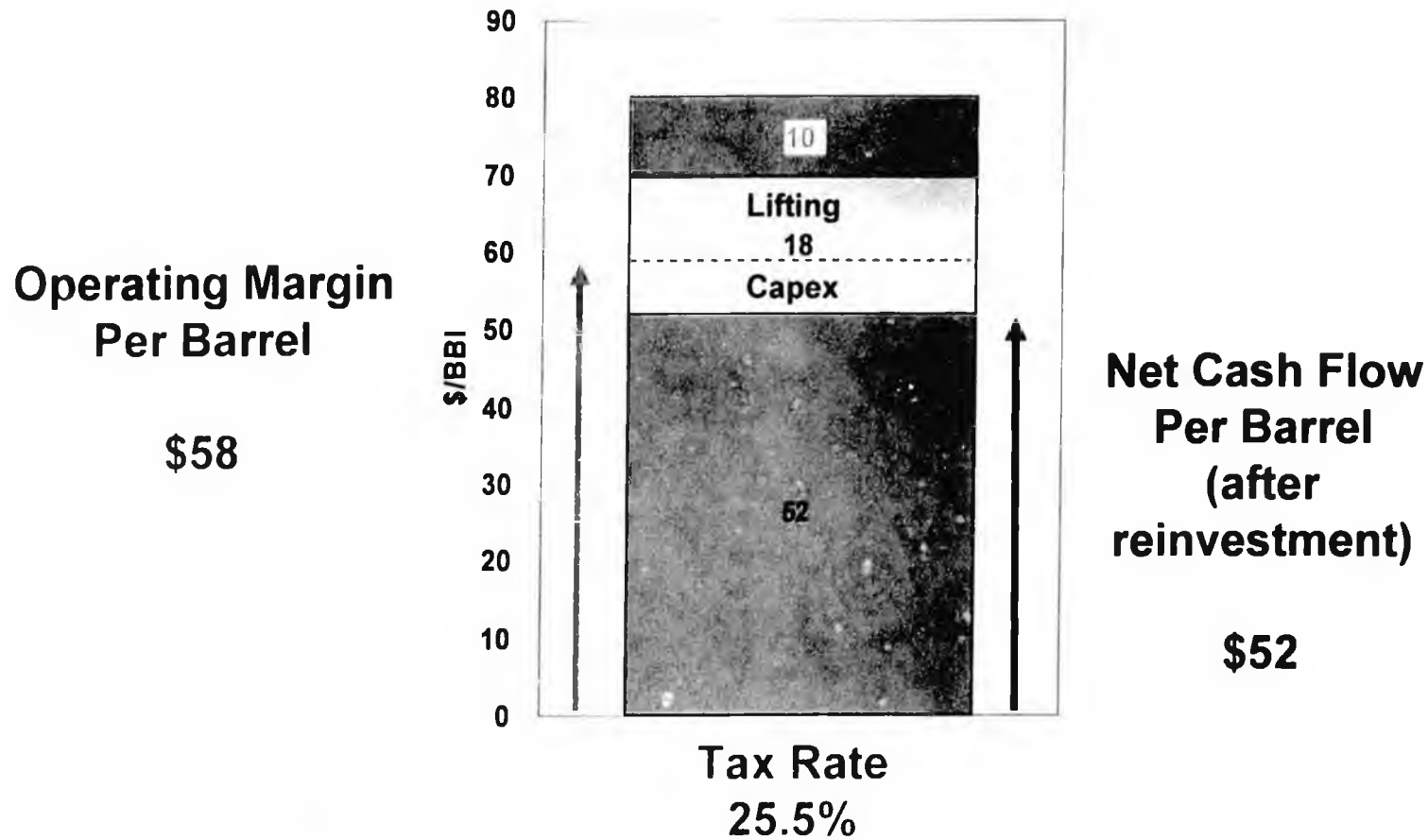
... the effective tax rate is lowered further to 23%*

* In this example

PPT Is Really A Tax On Net Cash Flow Per Barrel



... or, a tax on net revenues that are not reinvested ...



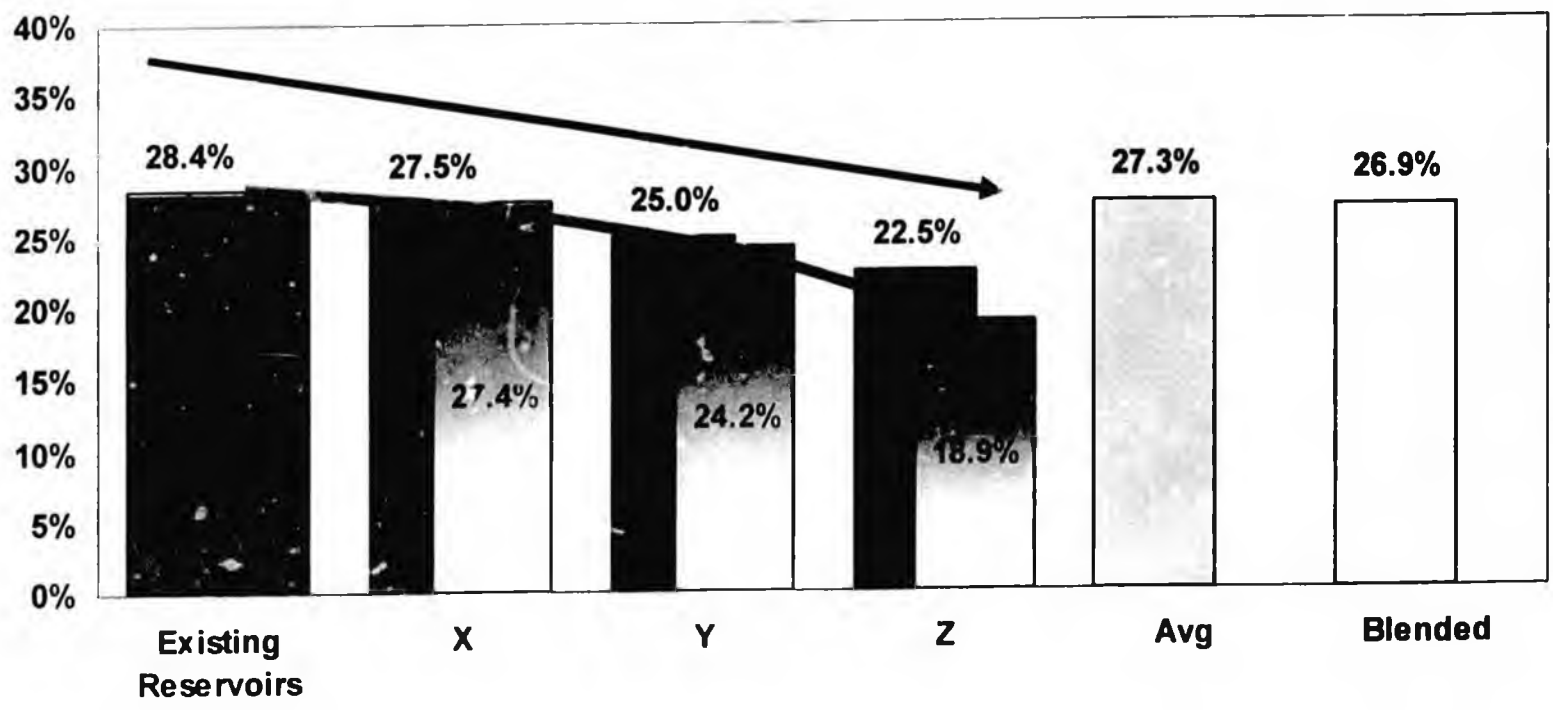
House Oil & Gas Committee

Gross Progressivity Amendment



PPT Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

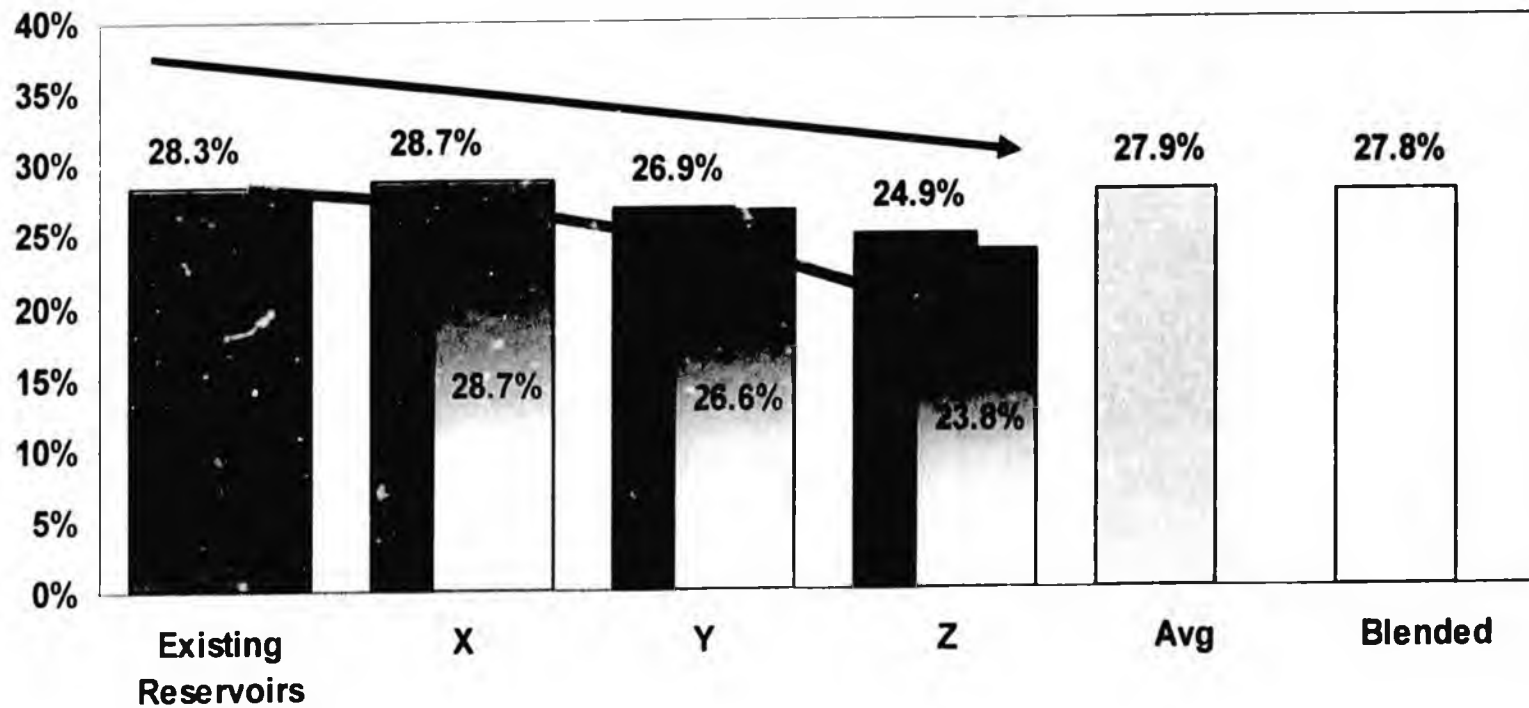


The progressivity can be seen through the lower effective tax rate on lower margin fields



House Oil & Gas Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

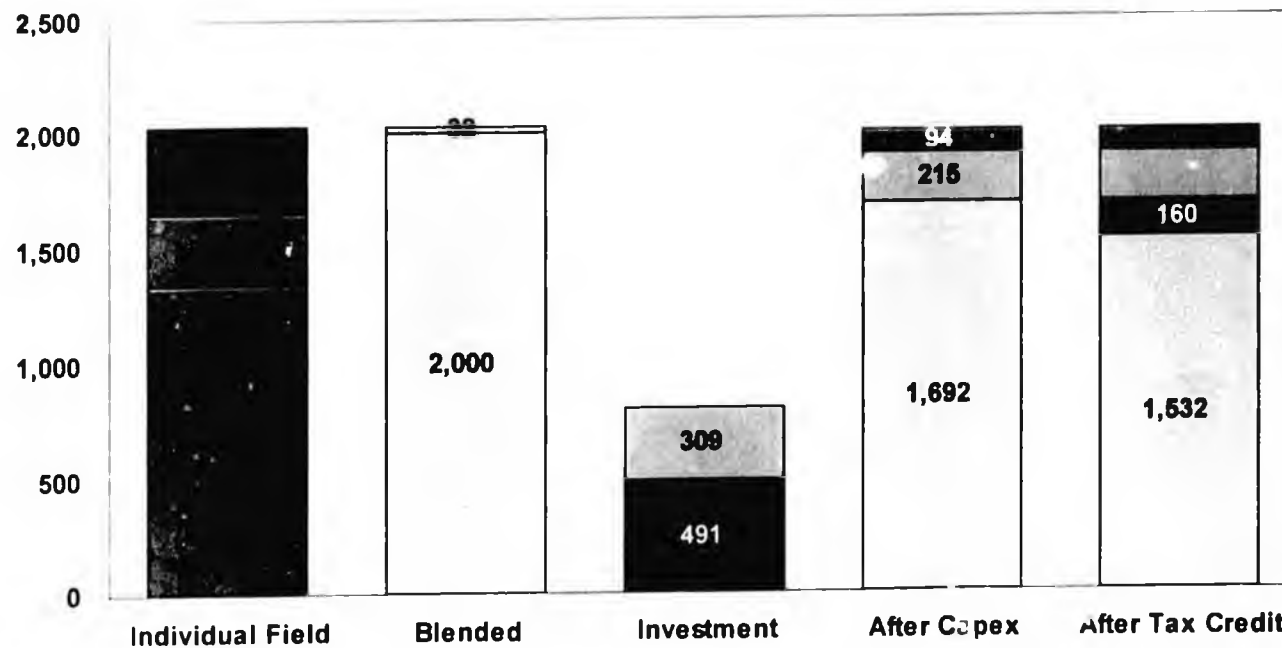


The bulk of the increased burden in this case is being borne by the lower margin fields ...



PPT Progressivity

Tax Allocable By Field Within Portfolio

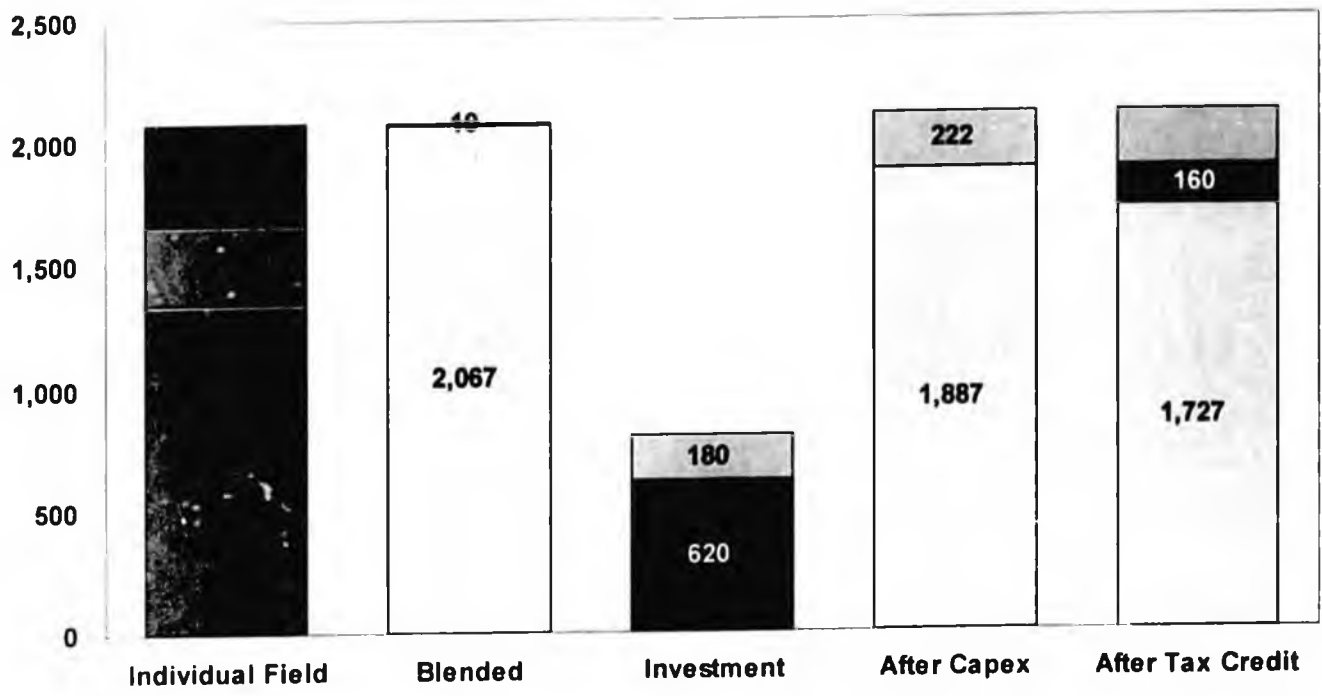


**Under PPT progressivity this portfolio would pay \$1,532 million
at \$80 ANS West Coast
\$2 Bn before the capital investment**



House Oil & Gas Progressivity

Tax Allocable By Field Within Portfolio



**Under House O&G progressivity this portfolio would pay \$1,727 million
-only \$67 million before the capital investment
The net cost of the investment rises from \$331 million to \$460 million***

* Before State and Federal tax impacts



Conclusions

- **A net tax on the margin is a tax on the retained cash flow and not just a tax on simple profitability**
- **Corporate ring fence for production tax allows the effective rate to vary between more, and less, profitable fields**
- **More aggressive net progressivity provides a greater differentiation on the effective rate than simple gross progressivity**
 - **Less/lower taxes at low margins**
 - **More/higher taxes at high margins**

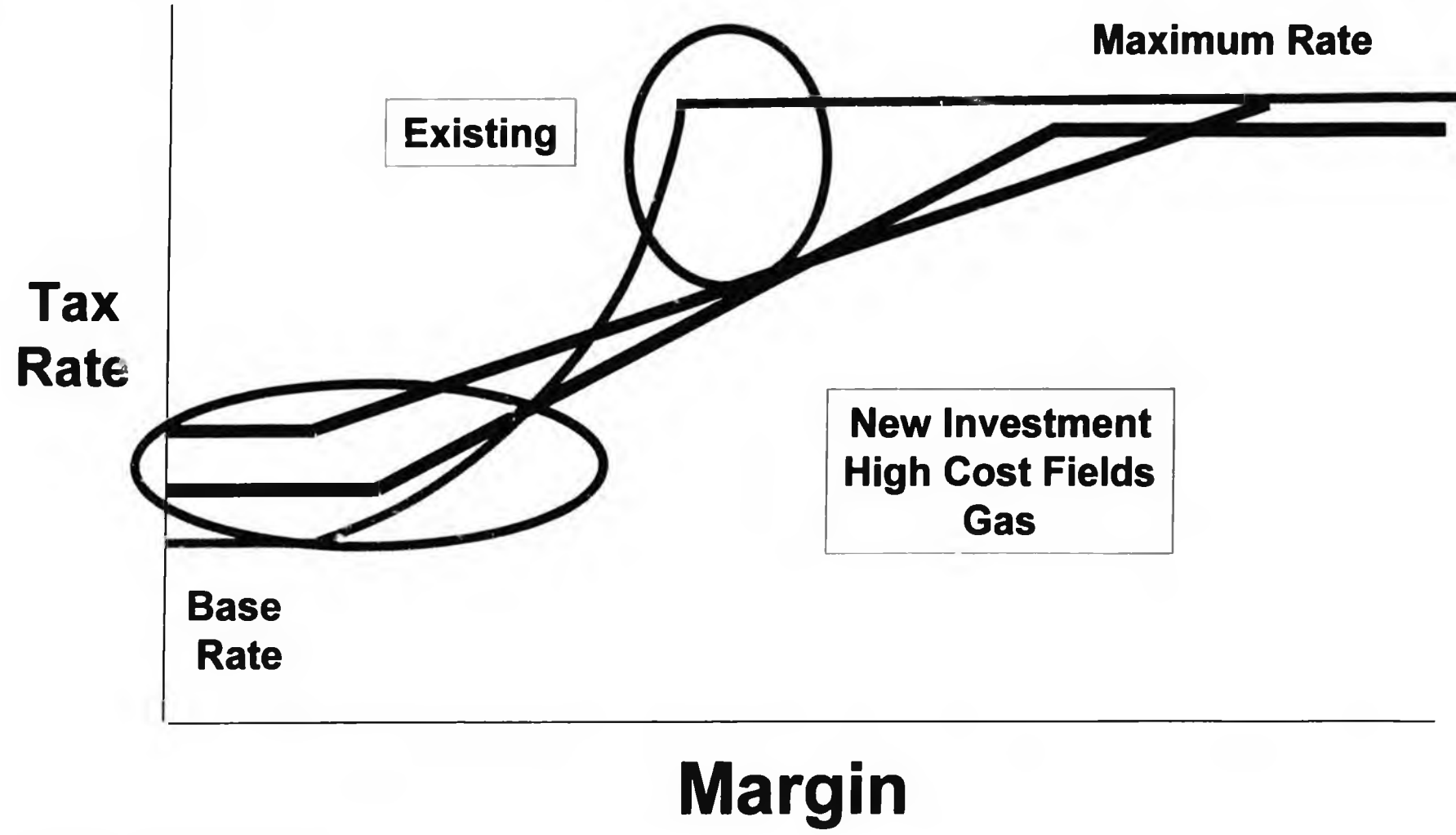


Progressivity

- **Progressivity, based on “net”, as manifested in the PPT/ACES structure is more responsive to individual field profitability than that in a “gross” structure**
- **Greater progressivity (raising the maximum rate and / or slope) can achieve even greater differentiation**
 - More tax on legacy investments benefits from current higher prices – that will drop back if prices drop back
 - Lower tax rates on higher cost / lower margin new investments



Aggressive Progressivity



Not The End But a New Beginning

30 October 2007



Gaffney, Cline & Associates Inc.

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RAR/jlm/C1492.00/gcah.292.07

October 19, 2007

MEMORANDUM

RE: Oil and Gas Reporting and Disclosure in Selected Countries

As part of the review of its oil and gas fiscal system, the State of Alaska is exploring ways to improve the administration of its 'net' based taxes. Many believe the State is at a disadvantage to the oil companies in auditing their compliance as little data are routinely provided to the State. As such, Gaffney, Cline and Associates (GCA) has been asked to prepare a brief overview of how the acquisition, distribution and publication of oil company data are handled in other oil and gas producing regimes.

SUMMARY

Provision by oil companies to host governments of detailed information pertaining to petroleum licenses and activities thereunder is routine around the world, usually as a condition of the license or contract under which the petroleum rights are granted. Certain data, including costs, may also be required (or covered, as well) by fiscal regulations governing different forms of taxation beyond general income tax provisions.

The information normally required to be provided encompasses the range from physical samples to activity plans and operating and financial data. The form of provision may vary, but formats consistent with electronic data exchange are developed for certain information. Where provided, data are generally at a well or field level of granularity.

Data provision is governed by various different confidentiality provisions, although sharing between different state/government entities appears more the standard than the exception. Basic geologic data are held confidential for periods of 2-5 years; although in some circumstances this may be as long as 10 years.

Data on fields under development and producing fields tend to either be released straight away, or are only released in aggregate form. For the most part, detailed data are only released on historical field or well production. Historical capital and operating cost data tend to be aggregated by country for disclosure, on an annual historical basis.

Limited amounts of data are also provided on a forecast basis. This is mixed between aggregated data and field-level data. Most of the field data so offered is reserves, but Denmark actually reports capital expenditure forecasts by field. No published forecast operating cost data has been identified.

Field data are typically submitted pursuant to two time-based criteria: at the time field exploration, appraisal or development plans are submitted, or a major revision to those plans is

MEMORANDUM

October 16, 2007

Page 2

incorporated, and on an annual basis for tracking and monitoring. Typically both situations will include production, capital and operating costs.

In its overview of reporting, GCA focused its efforts on reviewing practice in the petroleum producing countries of the North Sea, Canada, and Timor-Leste (where GCA recently assisted in the drafting of the Petroleum Act, the Petroleum Fiscal Act and associated regulations, drawing on "best practice" from around the world), although selected other examples are also included.

Considerable additional detail is available from websites and publications that go beyond the overview here, and should be studied further before detailed laws and regulations are drafted in Alaska.

DISCUSSION**Ownership of Data**

Bar very minor exceptions, it is only in the United States that private entities own mineral rights. In Alaska, the state owns the rights to minerals making it similar to all other international locations.

States then lease or grant those rights to petroleum companies for a period of time either via a license, concession, service agreement or production sharing agreement. In exchange for receiving the rights to exploit (the state's) hydrocarbon resources, the oil companies are routinely obligated to provide the state with most, if not all, of the data related to their petroleum operations. The legislation, regulations and contracts in most countries specify quite clearly that the state owns all data obtained or produced as part of petroleum operations.

Timor-Leste shall have title to all data and information, whether raw, derived, processed, interpreted or analysed, obtained pursuant to any Authorisation.

Some countries even go so far as to require that physical data, such as reservoir cores, are kept in-country at a state controlled facility.

Data and information acquired during the course of Petroleum Operations may be freely exported by Authorised Persons provided that the Ministry may require that an original, or in the case of a core, rock, fluid or other physical sample, a usable portion of the original, of all data and information, both physical and electronic, be kept in Timor-Leste.

Submission of Data

A variety of regulations usually stipulate the manner in which data are to be transmitted to the state. Physical data, such as cores or fluid samples, are packaged and labeled for long term storage. These are shipped to a facility designated by the state.

Other data, such as seismic, logs, production and costs, are supplied in two forms. First, the data are generally presented in the form of a routine report required by regulation. Reports are generally submitted in a non-editable format to ensure their integrity. Second, all data are

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supplied in their 'raw' format, usually electronically, in a fully usable and editable format. Regulations sometimes prescribe how this is to be done.

Material and information which the licensee, operator, contractor etc. possesses or prepares in connection with planning and implementation of petroleum activities pursuant to this Act shall be available in Norway and may be required to be submitted free of charge to the Ministry or to anyone designated by the Ministry. Such material and information shall be submitted in a format decided by the Ministry to the extent this is deemed reasonable. In this connection, the Ministry may also require analyses and studies to be carried out.

Types of Data

As noted earlier, most states maintain ownership to all data acquired in the course of petroleum operations. This data is then supplied to the state. The amount of data coming in is not inconsequential and can add up fast.

Appendix I is a list of the types of data typically supplied to the state. It is by no means exhaustive or complete but is meant to be a representation of what is available.

Once obtained, information may be designated as confidential or commercially sensitive. Depending on the nature of the data, it may be kept confidential for a period of time, usually 5 to 10 years.

Data Type	Data Acquisition Entity	Concessionaire
Seismic data	10 years	5 years
Magneto metric / Gravimetric data	10 years	5 years
Geochemical data	10 years	5 years
Well data	2 years	2 years

Example shown is from Brazil

Publication and Public Access

There is some variance in what a state chooses or is allowed to publish. The World Bank-led initiative on transparency (the Extractive Industries Transparency Initiative) has many countries rethinking their approach, but for the most part, countries still tend to keep most data confidential or aggregated at a level so as to prevent any identification of individual pieces.

There are a couple of exceptions. Timor-Leste recently passed legislation that is probably the most transparent of any government. By law the energy ministry in Timor-Leste is obligated to publish or make available to the public:

- (i) *copies of all Authorisations and amendments thereto, whether or not terminated;*
- (ii) *copies of all unitisation agreements;*
- (iii) *summaries of Authorisations (and amendments thereto, whether or not terminated) and unitisation agreements;*
- (iv) *approved Development Plans;*

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- (v) *all assignments and other dealings consented to in respect of Authorisations, subject to commercial confidence as to the commercial terms;*
- (vi) *all exemptions granted from, or agreeing to a variation or suspension of, the conditions of an Authorization;*
- (vii) *all such reports from companies acting in compliance with requirements under the Act and Authorisations in such manner and detail as required by their Authorisation and as provided by regulation; and*
- (viii) *all such reports by Authorised Persons on payments relating to Petroleum Operations made to the Government of Timor-Leste as are required by law.*

The last item makes public all data (i.e. production rates, capital and operating costs) related to the calculation of royalty, production share and profit oil.

Brazil, in an indirect manner, provides the means by which a knowledgeable person can ascertain the operating costs per company per field.

The Brazilian petroleum regulatory agency displays regularly in its web site price, production, royalties and windfall profit tax on a field-by-field basis. Based on this it is possible to assess, indirectly, the production cost of a given field. Once the windfall profit tax is known it is possible to calculate the taxable basis. By deducting the taxable basis from gross revenue minus royalties, the balance is total costs (capital plus operating).

North Sea Countries' Reporting

All four of the key North Sea jurisdictions (United Kingdom (UK), Norway, Denmark and Netherlands) have regulations and practices requiring companies to disclose information on a detailed basis. This information includes well and seismic data, plus detailed development plans / updates including production, capital and operating cost forecasts and annual updates / forecasts of the same information.

While the information is supplied by the companies on a detailed, field-by-field (or where required, well-by-well) basis, public reporting is much less detailed. Typically data will be aggregated on a country-wide basis, although in some cases life-of-field numbers (reserves, costs) may be reported. The main exception to this is historical production data, which is generally available on a detailed basis.

Costs reported for regulatory purposes are typically at a field level, and exclude overheads and other non-field allocated costs. Such costs would typically be incorporated in tax filings, and be governed by taxpayer confidentiality.

While not official government data, all North Sea countries have had available very good subscription-service data on a field-by-field basis. The services typically include full annual historic and forecast production, capital and operating cost data, and field economics. While the data sources incorporate all official public releases (from the state to official company publications), they also benefit from "guidance" from the companies themselves. In the latter cases, while not wanting to warrant data or even acknowledge its release, the companies find it useful to see that it is reasonable as they themselves are consumers of the data sets on fields in which they do not have an interest.

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The impact of these services is such that they are relied on heavily by investors and planners alike. While no substitute for official data, they have proven to be a significant driver of activity whereby new players can gain a good understanding of participants, the nature of oil and gas fields, and costs prior to entering an area.

Availability of such reporting has now spread to several countries in the world, although the accuracy of data may be variable from country to country, and subject to local considerations regarding allowing data release.

UK

The UK has significant regulations covering requirements for the provision of data. This is captured at a field level, both at the time of a Field Development Plan submission (and major revision), plus on an annual or semi-annual survey basis. While collected by the Department of Trade and Industry (DTI), and shared amongst Crown (Government) bodies, disclosure is more limited.

Detailed information is made publicly available on well / field production data. However, both cost (capital and operating) and fiscal (tax and royalty receipts) are disclosed only on an aggregate basis. There are some exceptions where detailed data is provided to persons or commercial organizations undertaking studies for Government bodies; however these are provided under conditions of confidentiality and the underlying detail is not disclosed in the final report.

Supplementary detail provided in Appendix II shows the regulations and format of information provision, and examples of disclosure (with the actual numbers generally being available in tabular format as well).

Denmark

Denmark receives detailed field-by-field production and cost data on an annual basis, although it has not standardized reporting by operator, reflecting principally that it only has five operators in the country.

Public disclosure and reporting provides a mix of detail. Country summaries of historic and forecast data are provided, but so is investment detail on a field by field basis, (See Appendix III).

In addition, though, field by field summaries are provided which provide a good background on historic, though limited future data.

Operating costs, on the other hand, are only reported on an aggregate basis.

Norway

Norway requires operators to provide detailed field production, capital and operating cost forecasts as part of a development plan, and on an annual basis. Operators are required to submit detailed production and cost forecasts each year in spreadsheet form to the Norwegian Petroleum Directorate (NPD) (See Appendix IV).

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M E M O R A N D U M

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Each year the NPD will produce a long report on operations on the Norwegian Continental Shelf, with a lot of production and cost data provided in aggregate form. In addition, however, field summaries are also provided showing reserves and capital (expected total and remaining) for both producing fields and fields in development. No annual-time series is available, although analysis of several years' reports will allow a historic time-series to be developed on a field-by-field basis.

Operating cost data is available only on a consolidated basis, as are statistics on government revenues from royalties and taxes.

Netherlands

The Netherlands publishes similar information to the other North Sea countries with regard to production data, although it tends to aggregate it on a license basis, thereby covering possibly several fields rather than a single field. Resource estimates are published with an onshore/offshore split, but not at a field or license detail level.

Historical fiscal revenues are detailed, but no cost information is readily discernable.

Such information is provided to EBN, a state-owned oil and gas company that is a partner in all oil and gas licenses. However, detailed information of all types is considered commercially confidential and not disclosed publicly.

Canada (Nova Scotia and Newfoundland-Labrador)

Canada divides jurisdiction for oil and gas between the Provinces and Federal government. The Western Provinces of Alberta, British Columbia and Saskatchewan each administer their own regimes, while Frontier Lands and the Maritimes operate jointly with the Federal government.

Nova Scotia and Newfoundland-Labrador have similar, though separate, regimes with many common provisions, operating under joint boards (Canada-Nova Scotia Offshore Petroleum Board, and Canada Newfoundland-Labrador Offshore Petroleum Board).

The Provinces have strict hard-copy and electronic formatting requirements for all technical data submissions. Detailed by field production reports are filed (and disclosed on a monthly basis) in addition to a weekly progress report of all activities in licensed areas.

The Provinces' Petroleum Boards are required to conduct a Public Review of the Development unless the Board determines a review is not necessary in the public interest. The guidelines for the contents of the Development Plan are relatively comprehensive.

An example of the information disclosure from the proposed development plan for Nova Scotia's Deep Panuke field that is currently under consideration, and providing production forecasts and indicative costs, is shown in Appendix V. Similar disclosure was made previously for the Sable Island Gas Project.

An example of the data disclosure requirements in Newfoundland-Labrador is given in Appendix VI.

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In addition to the comprehensive submission and disclosure requirements for the development plan, both Atlantic Canada Provinces mandate public disclosure of all well and geological data after specified periods between 2 and 5 years depending on the type of information.

Attachments

Appendices	I:	Types of Data
	II:	UK Detail
	III:	Denmark Detail
	IV:	Norway Detail
	V:	Nova Scotia Detail
	VI:	Newfoundland-Labrador Detail

IN ADDITION TO THE WORKSHEET ATTACHED TO THIS REPORT, THE FOLLOWING INFORMATION IS PROVIDED FOR YOUR INFORMATION:

APPENDICES

TYPES OF DATA

EXPLORATION AND APPRAISAL

- Seismicity
- Gravity
- Magnetic
- Radiometric
- Geologic
- Stratigraphic
- Structural
- Paleogeographic

Appendix I:

Types of Data

DEVELOPMENT

- Production
- Reservoir
- Well
- Completion
- Drilling
- Production
- Reservoir
- Well
- Completion
- Drilling

PRODUCTION

- Production
- Reservoir
- Well
- Completion
- Drilling
- Production
- Reservoir
- Well
- Completion
- Drilling

RESERVOIR

- Production
- Reservoir
- Well
- Completion
- Drilling

TYPES OF DATA

- **EXPLORATION AND APPRAISAL**
 - Joint Operating Agreements
 - Work Programs and Budgets
 - Seismic
 - Daily Drilling Reports
 - Logs
 - Well tests
 - Geological Models and Maps

- **DEVELOPMENT**
 - Development Plans with Opex and Capex Projections
 - Contracts
 - Construction Progress Reports
 - Drilling Reports
 - Reservoir Characterization

- **PRODUCTION**
 - Work Programs and Budgets
 - Sales, Revenues and Pricing
 - Transportation Agreements
 - Sales Contracts
 - Production
 - Injection
 - Opex (as spent and forecast)
 - Capex (as spent and forecast)
 - Facility Maps and Studies
 - Safety and Environmental reports
 - Training and Development

- **ABANDONMENT**
 - Abandonment Plan and Budget
 - Progress Reports
 - Environmental Clean-up Assessment



**Appendix II:
UK Detail**



Figure 4: UK North Sea Expenditure 1970-2006

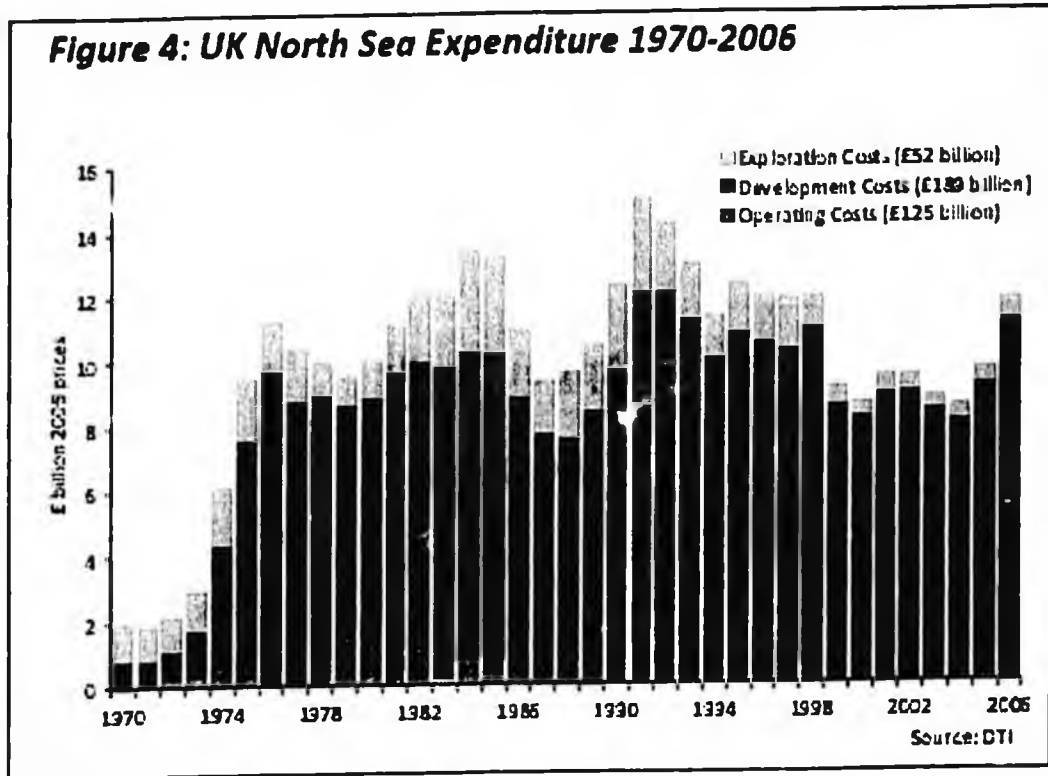


Figure 6: UKCS Taxes 1991-2008

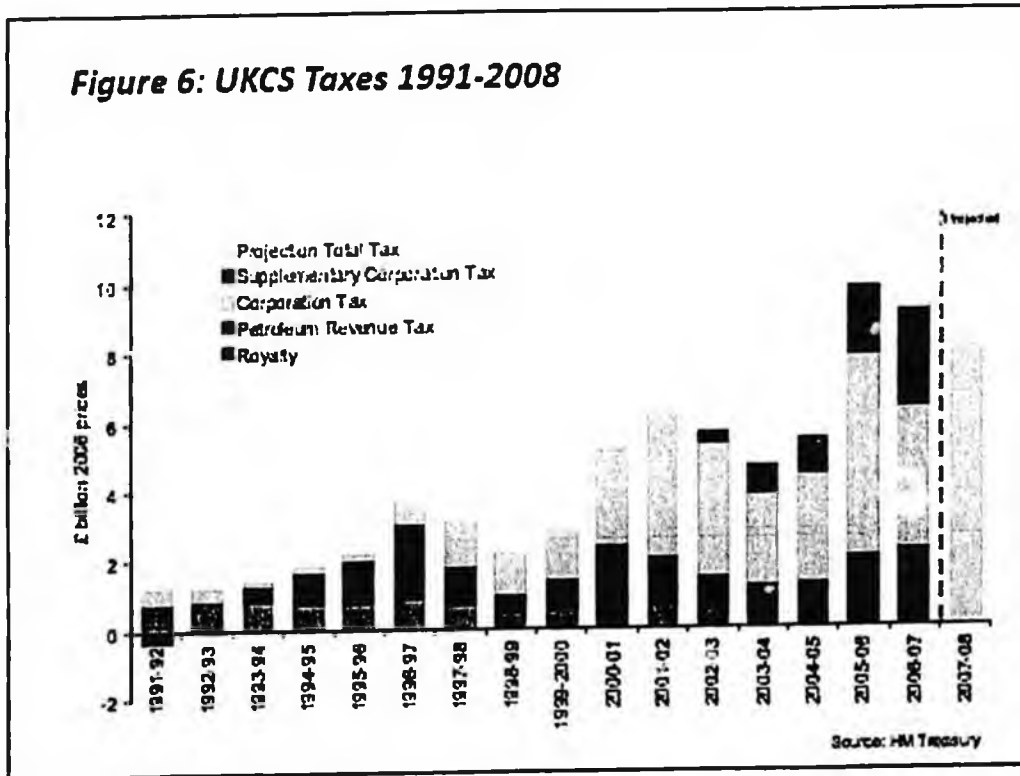
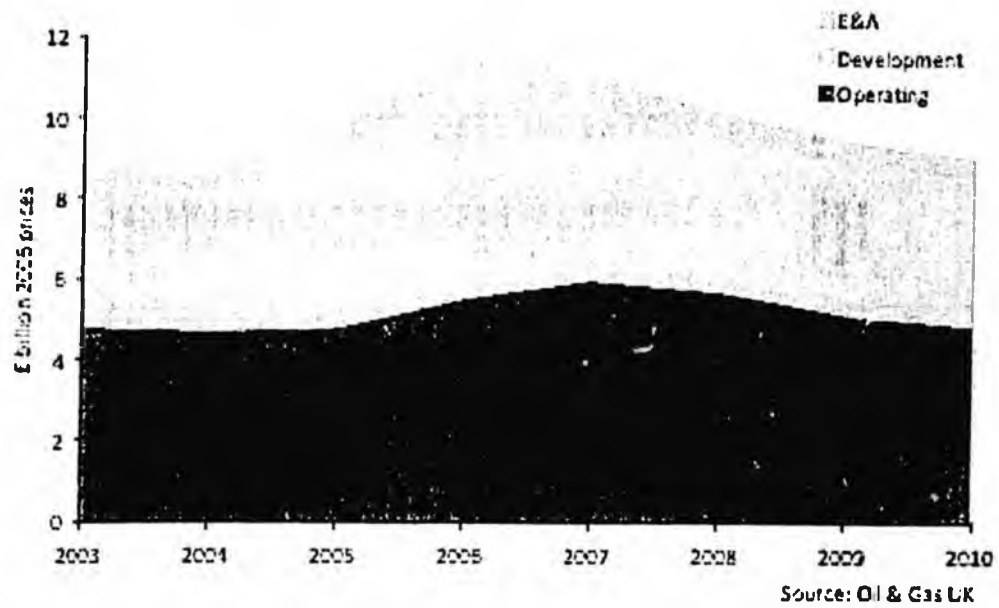


Figure 30: UKCS Expenditure Forecast 2003-2010



Income from and Expenditure on UK Continental Shelf Exploration, Development and Operating Activities
 (£ million)

	Income				Total Income	Expenses				Gross Operating Surplus ⁽³⁾	Capital Expenditure			Prices		GDP Deflator (2005=100)	
	Oil Sales	NGL Sales	Gas Sales	Other Income ⁽¹⁾		Operating Costs	of which decom- missioning costs	Other expenses ⁽²⁾	Total Expenses		EBA ⁽⁴⁾	of which relating to EBA	Investment other than EBA	Total	Average Oil Price (\$/barrel)		Average Gas Price (\$/therm)
1970	0	0	3	4	6	6	n/a	0	6	-2	33	n/a	53	78	n/a	n/a	9.8
1971	0	0	53	8	60	17	n/a	0	17	78	57	n/a	72	120	n/a	n/a	10.8
1972	0	0	114	3	124	15	n/a	0	15	110	43	n/a	112	164	n/a	n/a	11.7
1973	0	2	133	11	146	18	n/a	0	18	128	59	n/a	216	264	n/a	n/a	12.8
1974	0	3	166	21	190	20	n/a	0	20	170	153	n/a	584	787	n/a	n/a	14.4
1975	43	16	192	29	277	46	n/a	0	46	231	242	n/a	1,374	1,810	n/a	n/a	18.3
1976	524	21	238	21	824	130	n/a	0	130	794	301	n/a	2,070	2,872	n/a	n/a	21.1
1977	2,187	29	317	23	2,656	237	n/a	0	237	2,366	375	n/a	2,167	2,482	n/a	2.1	24.0
1978	2,371	35	432	12	3,260	346	n/a	0	346	2,904	261	n/a	2,170	2,481	n/a	3.1	26.8
1979	5,641	53	538	44	6,876	532	n/a	18	514	5,787	241	n/a	2,064	2,885	n/a	3.8	30.7
1980	8,719	132	647	82	9,600	692	n/a	34	726	8,854	379	n/a	2,283	3,747	n/a	4.8	36.7
1981	12,205	135	843	114	13,297	1,017	n/a	45	1,062	12,235	553	n/a	2,847	3,887	n/a	5.5	40.8
1982	14,129	312	956	163	15,560	1,338	n/a	73	1,411	14,174	875	n/a	3,059	3,984	142.3	7.4	43.9
1983	16,486	528	1,117	180	18,311	1,495	n/a	67	1,562	16,787	953	n/a	2,853	3,846	148.3	8.4	46.3
1984	19,927	659	1,293	255	22,134	1,733	n/a	52	1,785	20,350	1,355	n/a	3,169	4,584	164.9	10.3	48.4
1985	19,204	692	1,739	384	21,999	2,248	n/a	76	2,324	19,654	1,445	n/a	2,794	4,289	158.3	11.9	51.1
1986	9,909	386	1,927	459	11,681	2,144	n/a	67	2,211	9,470	1,008	n/a	2,419	3,467	73.3	12.4	52.9
1987	9,613	368	1,993	531	12,505	2,107	n/a	55	2,162	10,333	809	n/a	2,044	3,668	81.7	12.4	56.7
1988	7,364	248	2,048	858	10,518	2,053	n/a	59	2,112	8,120	1,129	n/a	2,128	3,288	63.4	13.1	59.2
1989	7,214	272	2,187	547	10,220	2,333	n/a	57	2,390	7,833	1,162	n/a	2,635	3,817	81.1	14.2	61.6
1990	8,432	277	2,377	436	11,491	2,552	n/a	45	2,597	8,552	1,537	n/a	3,478	5,116	94.6	14.3	65.6
1991	7,578	385	2,998	476	11,437	2,285	n/a	59	2,344	8,073	1,955	n/a	5,121	7,067	85.3	15.9	71.0
1992	7,420	383	3,016	625	11,444	3,312	n/a	53	3,365	8,080	1,603	n/a	5,428	6,886	81.9	15.8	76.0
1993	8,110	523	3,559	693	12,885	3,651	n/a	47	3,728	9,150	1,213	n/a	4,661	6,874	85.9	15.0	78.0
1994	8,964	528	3,838	974	14,304	3,863	n/a	40	3,903	10,431	939	150	3,871	4,800	77.3	16.3	79.2
1995	9,881	614	4,141	1,155	15,802	3,913	n/a	37	3,950	11,852	1,056	234	4,355	5,400	81.1	16.3	81.4
1996	11,850	749	5,295	1,243	19,137	3,978	n/a	31	4,009	15,127	1,057	190	4,364	6,461	97.3	16.6	84.2
1997	13,327	793	6,214	1,279	21,613	4,153	n/a	34	4,187	17,377	1,194	191	4,263	6,467	87.4	16.7	86.4
1998	7,487	551	5,313	1,453	14,804	4,193	n/a	111	4,304	10,503	762	129	4,555	5,760	58.9	16.2	88.9
1999	10,257	727	5,031	1,435	17,450	4,249	n/a	282	4,531	12,920	457	55	3,083	3,820	83.3	13.7	90.9
2000	15,275	1,117	6,836	1,468	25,496	4,363	n/a	109	4,472	21,024	349	49	2,750	3,008	138.1	18.8	92.1
2001	13,546	953	6,143	1,435	22,077	4,357	n/a	49	4,406	18,789	423	34	3,570	3,900	125.7	19.0	94.1
2002	13,629	834	6,189	1,397	22,139	4,596	n/a	48	4,644	19,475	329	45	3,598	3,888	123.8	15.4	97.0
2003	12,355	1,105	7,534	1,539	22,533	4,432	n/a	8	4,440	19,368	314	42	3,412	3,740	123.3	17.4	100.0
2004	13,477	1,255	7,443	1,178	23,353	4,564	n/a	57	4,621	18,613	358	57	3,302	3,886	154.3	21.3	102.8
2005	15,656	1,694	8,922	1,451	27,723	5,113	n/a	128	5,241	23,452	463	34	4,371	4,891	215.8	27.8	104.9

Notes

(1) Revenues from pipelines and terminals, and other revenues of operators and production licensees.

(2) Other costs of operators and production licensees not attributable to oil or gas fields.

(3) Gross Operating Surplus = Total Income less Total Expenses.

(4) EBA costs include Exploration and the cost of Appraisals, well drilled prior to development approval. The figures exclude change in stocks and book value of stocks.

Well No:	Field Name:	Operator:	Company contact:	Date:	CONVERSION FACTOR		Please indicate barrels and suffix conversion factor																
	Type of development:	Contact details:			Oil																		
Discovery date:					NGL																		
Depth:					Gas																		
	Costs (\$ million constant 2007 prices)										TARIFF												
	Production			Sales			Other oil/gas uses			CAPEX			OPEX			1st \$ expenditure/income							
Year	Oil 000 tonnes	NGL 000 tonnes	Gas million barrels	Oil 000 tonnes	NGL 000 tonnes	Gas million barrels	Gas Flaring million barrels	Re-injection million barrels	Fuel use 000 tonnes	Other oil/gas usage spent from sales (please specify)	Exploration and Appraisal Drilling	Development Drilling expenditure	Other Capital expenditure	Operating expenditure (excluding tariff payments and lease costs)	Lease Costs (FPSOs etc)	Decommissioning Costs	Oil \$/tonne	NGL \$/tonne	Gas p/therm	Tariff payment in field per barrel \$ million	Tariff receipts from old fields \$ million	Tariff receipts from new fields \$ million	
Previous spend 1997																							
Previous spend 1998																							
Previous spend 1999																							
Previous spend 2000																							
Previous spend 2001																							
Previous spend 2002																							
Previous spend 2003																							
Previous spend 2004																							
Previous spend 2005																							
Previous spend 2006																							
Already committed in 2007																							
other 2007																							
2008																							
2009																							
2010																							
2011																							
TOTAL																							
List Licenses and give % holding within field		Gas Contract Information:																					
EXPORT ROUTE		Premium/discount to Brent Crude:																					
Oil		Please indicate using plus or minus \$ per barrel or p/therm																					
NGL		Notes:																					
Gas																							
Once complete please send to field team coordinator by email																							

Example of spreadsheet form of data to be submitted with Field Development Plan or update.

**Appendix III:
Denmark Detail**

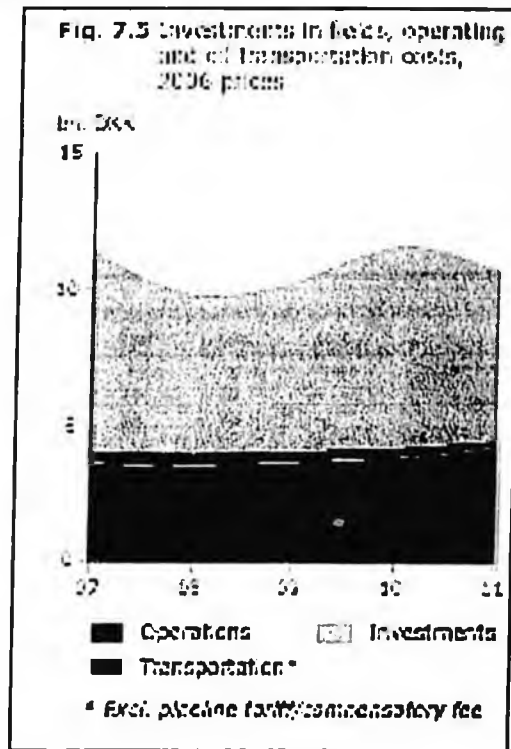
Table 7.4 Investments, DKK million, nominal prices

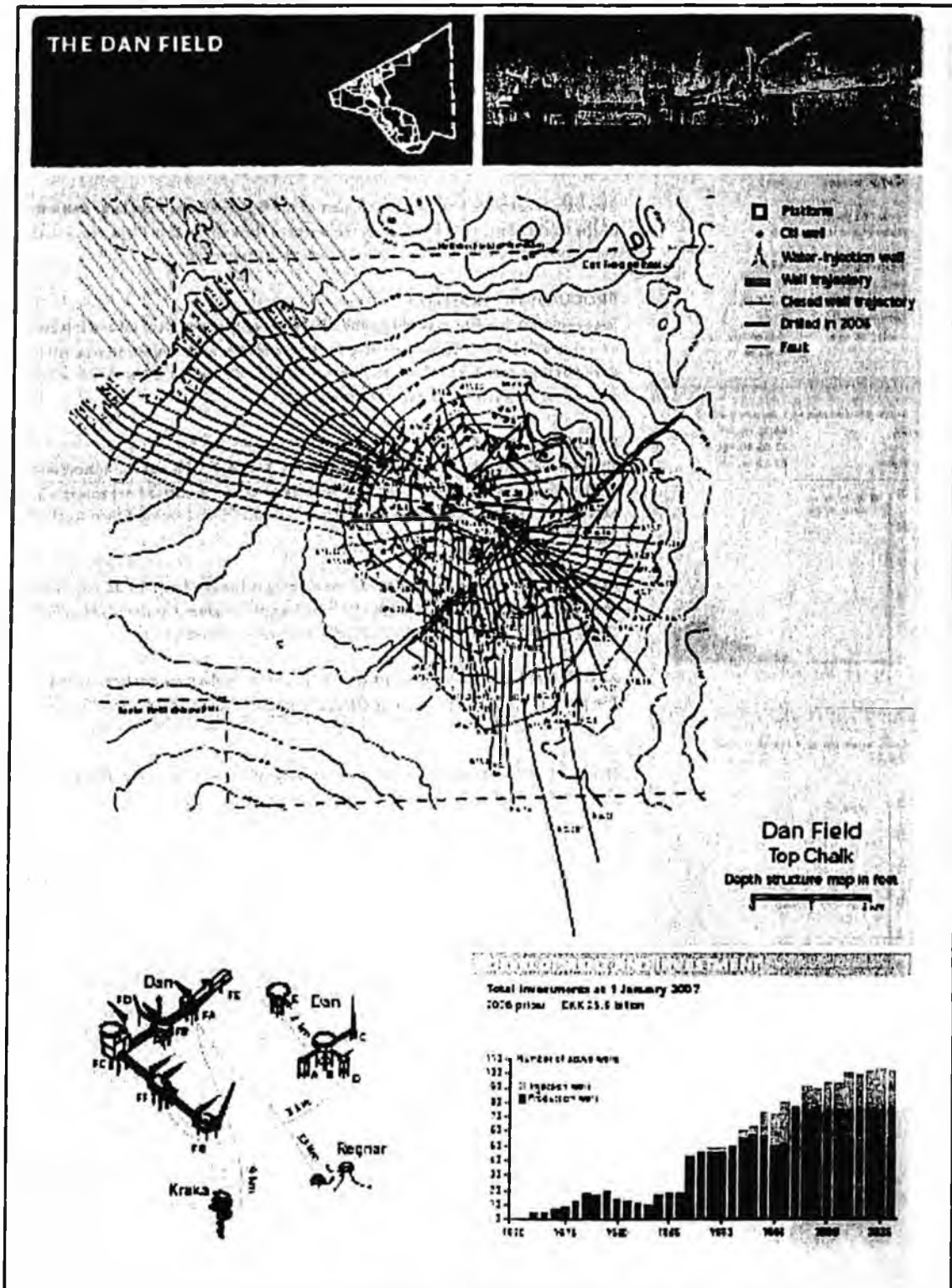
	2002	2003	2004	2005	2006*
Cecille	221	660	309	(16)	4
Dagmar	-	-	-	-	148
Dan	437	943	750	750	684
Gorm	242	107	108	291	304
Halldan	1,412	1,779	1,124	683	1,290
Harald	0	4	21	53	3
Kraka	3	-	2	-	-
Mini	265	1,253	319	163	19
Roar	-	-	-	-	-
Rolf	-	37	4	-	1
Sni	111	406	415	73	140
Skjold	5	77	8	11	4
South Arne	849	764	762	310	451
Svend	223	-	-	-	-
Tyra	85	305	459	1,050	1,510
Tyra Southeast	569	82	96	45	-
Valdemar	(1)	200	52	553	992
NOGAT pipelines	-	766	664	11	-
Not allocated	31	(31)	2	5	97
Total	5,475	7,386	6,105	3,951	6,658

* Estimate

Table 7.5 Estimated investments in development projects, 2007-2011, DKK billion, 2016 prices

	2007	2008	2009	2010	2011
Ongoing and approved					
Adda	-	0.1	0.6	-	-
Alma	-	0.6	0.5	-	-
Boje	-	-	-	0.9	-
Cecille	-	-	-	-	-
Dagmar	-	-	-	-	-
Dan	0.9	0.6	-	-	-
Ely	0.3	1.6	-	-	-
Gorm	0.1	0.0	-	-	-
Halldan	1.0	0.9	0.1	-	-
Harald	0.0	0.1	-	-	-
Kraka	0.3	-	-	-	-
Lulita	-	-	-	-	-
Mini	0.1	-	-	-	-
Regnar	-	-	-	-	-
Roar	-	-	-	-	-
Rolf	-	-	-	-	-
Sni	0.3	-	-	-	-
Skjold	-	-	-	-	-
South Arne	0.8	-	-	-	-
Svend	-	-	-	-	-
Tyra	0.4	0.4	0.4	0.0	1.3
Tyra Southeast	0.5	-	-	-	-
Valdemar	1.6	0.7	-	-	-
Total	7.3	6.1	1.6	0.8	1.3
Planned	-	-	-	-	0.8
Possible	-	0.7	4.7	6.6	4.0
Expected	7.3	6.8	6.3	7.4	6.1





FIELD DATA as of January 2007

Project: Abby
 Location: Block 5124/17
 Licence: F - Concession
 Operator: Norsk O&G AS
 Reservoir: 1991
 Year in service: 1973

Producing well: 54
 Water injection wells: 20

Water depth: 40 m
 Field area: 121 km²
 Reservoir depth: 1,820 m
 Reservoir rock: Chalk
 Geological age: Cretaceous

PRODUCTION

Cum. production as of 1 January 2007
 Oil: 88.35 m. m³
 Gas: 21.26 bn. Nm³
 Water: 81.19 m. m³



INJECTION

Cum. injection as of 1 January 2007
 Water: 197.36 m. m³



ACCUMULATED GAS IN RESERVOIR

Oil: 23.8 m. m³
 Gas: 6.3 bn. Nm³



REVIEW OF GEOLOGY

The Dan Field is an anticlinal structure, induced partly due to salt tectonics. A major fault divides the field into two reservoir blocks, which, in turn, are intersected by a number of minor faults. The chalk reservoir has high porosity, although low permeability. There is a gas cap in the field.

Recovery takes place from the central part of the Dan Field and from large sections of the flanks of the field. Particularly the western flank of the Dan Field, close to the Halfdan Field, has demonstrated good production properties.

PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water. Water injection was initiated in 1983, and later water injection was introduced in large sections of the field. The recovery of oil is optimized by flooding the reservoir with water to the extent possible.

PRODUCTION FACILITIES

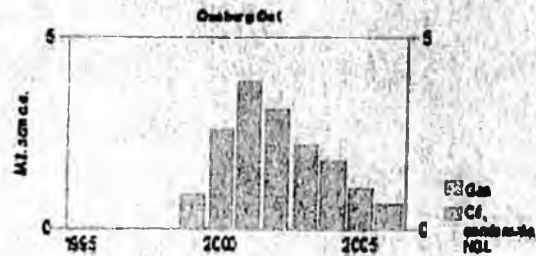
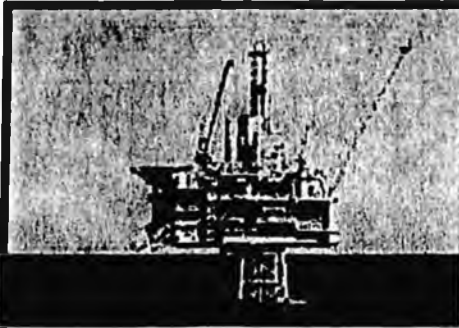
The Dan Field comprises six wellhead platforms, A, D, E, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FC, two processing and accommodation platforms, B and G, and two gas flare stacks, C and FD.

At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Ragnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

After final processing, the oil is transported to shore via the riser platform, Gorm E. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

The Dan Field has accommodation facilities for 97 persons on the FC platform. The B platform has accommodation facilities for five persons.

**Appendix IV:
Norway Detail**



Oseberg Øst

Block and production license	Block Øst-6, production license OGI, awarded 1979												
Discovery	1961												
Development approved	11.10.1988 by the King in Council												
On stream	01.05.1996												
Operator	Norsk Hydro Produksjon AS												
Licensees	<table border="0"> <tr> <td>Mobil Development Norway AS</td> <td>4.70 %</td> </tr> <tr> <td>Norsk Hydro Produksjon AS</td> <td>34.00 %</td> </tr> <tr> <td>Norsk ConocoPhillips AS</td> <td>3.40 %</td> </tr> <tr> <td>Petoro AS</td> <td>23.00 %</td> </tr> <tr> <td>Statol ASA</td> <td>13.00 %</td> </tr> <tr> <td>Total E&P Norge AS</td> <td>18.00 %</td> </tr> </table>	Mobil Development Norway AS	4.70 %	Norsk Hydro Produksjon AS	34.00 %	Norsk ConocoPhillips AS	3.40 %	Petoro AS	23.00 %	Statol ASA	13.00 %	Total E&P Norge AS	18.00 %
Mobil Development Norway AS	4.70 %												
Norsk Hydro Produksjon AS	34.00 %												
Norsk ConocoPhillips AS	3.40 %												
Petoro AS	23.00 %												
Statol ASA	13.00 %												
Total E&P Norge AS	18.00 %												
Reserves reserves	<table border="0"> <tr> <td>Original:</td> <td>Participating as of 31.12.2006</td> </tr> <tr> <td>27.8 million scm oil</td> <td>11.7 million scm oil</td> </tr> <tr> <td>0.4 billion scm gas</td> <td>0.2 billion scm gas</td> </tr> </table>	Original:	Participating as of 31.12.2006	27.8 million scm oil	11.7 million scm oil	0.4 billion scm gas	0.2 billion scm gas						
Original:	Participating as of 31.12.2006												
27.8 million scm oil	11.7 million scm oil												
0.4 billion scm gas	0.2 billion scm gas												
Production	<table border="0"> <tr> <td>Estimated production in 2007:</td> <td></td> </tr> <tr> <td>Oil: 10,000 barrels/day</td> <td>Gas: 0.02 billion scm</td> </tr> </table>	Estimated production in 2007:		Oil: 10,000 barrels/day	Gas: 0.02 billion scm								
Estimated production in 2007:													
Oil: 10,000 barrels/day	Gas: 0.02 billion scm												
Investment	<table border="0"> <tr> <td>Total investment is expected to be NOK 1.02 billion (2007 values)</td> </tr> <tr> <td>NOK 0.9 billion have been invested as of 31.12.2006 (2007 values)</td> </tr> </table>	Total investment is expected to be NOK 1.02 billion (2007 values)	NOK 0.9 billion have been invested as of 31.12.2006 (2007 values)										
Total investment is expected to be NOK 1.02 billion (2007 values)													
NOK 0.9 billion have been invested as of 31.12.2006 (2007 values)													
Operating status	In operation												
Main supply base	Mongstad												

Development:

Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is 100 metres.

Reserves:

The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil-bearing layers of varying reservoir characteristics within the Middle Jurassic Brent group.

Recovery strategy:

The field is produced with pressure maintenance using both water injection and WAG (water alternating gas) injection.

Transport:

The oil is sent by pipeline to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) to the Sævi terminal. The gas is mainly used for injection, gas lift and fuel.

Status:

Various measures for increased oil recovery are being evaluated in an ongoing process. A new drilling campaign is expected to yield increased production. The first well in the new drilling campaign is planned to be on stream in February 2008.

Appendix V:

Nova Scotia Detail

(from Deep Panuke Development Plan)

Year	P90		P50		P10		Mean	
	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)
2010	5.7	202	5.7	201	5.7	202	5.7	201
2011	8.5	300	8.4	300	8.5	300	8.5	300
2012	7.0	249	8.5	300	8.4	300	8.2	291
2013	4.5	159	6.4	228	8.4	300	6.2	219
2014	3.1	110	4.8	171	7.7	275	5.0	177

6.3.1 Development Phase Expenditures

Estimates for the development phase include costs incurred by EnCana, as operator of the Project, from the fourth quarter 2006 to first gas production, scheduled to occur in the fourth quarter of 2010.

The costs shown in Table 6.2 are for the M&NP option, and exclude any costs associated with the MOPL, which will be included as operating costs payable during the production life of the Project.

The SOEP Subsea Option would see a reduction in the cost of the export pipeline during the Development Phase. However, there would be an increase in operating costs for tariffs charged as a result of using the SOEP pipeline. At this time, these costs are not defined.

	CS Millions 2006
EnCana Project Management & Engineering	115
Subsea	135
Export Pipeline	200
Drilling and Completions	160
<i>Subtotal:</i>	610
<i>Contingency:</i>	90
Total Cost to First Gas	700

Appendix VI:

Newfoundland-Labrador Detail

3.14 GUIDELINES FOR DEVELOPMENT PLAN (PART II)

Part II of the Development Plan should consist of the studies, analyses and evaluations, or other information and proposals, in support of Part I of the Plan. In accordance with the Acts, proprietary information provided in Part II will not be disclosed without the proponent's consent.

The Acts also require that petrophysical, fluid, core and well testing data, analyses and evaluations, be provided to the Board for reasons other than as part of the Development Plan submission. If the proponent wishes to rely on this material to support the Development Plan, the material should be referenced explicitly but need not be resubmitted. The confidentiality status of such information will be determined in accordance with the relevant provisions of the Acts.

The following are to be provided where applicable and when available:

- geological studies;
- geophysical studies;
- petrophysical studies;
- reservoir engineering studies, including rock and fluid data and analyses, and reservoir simulation studies;
- original oil and gas-in-place and recoverable reserves studies;
- production engineering information and studies;
- field hydraulic studies;
- production and transportation systems studies;
- environmental studies and analyses;
- plans for waste treatment and disposal;
- development cost data and economic analyses of alternatives;
- information related to matters of conservation, safety of operations and pollution prevention; and,
- any other studies that were used in support of the Development Plan.

C. Huggins
31 October
marked copy

Alaska's Equitable Share

Some Further Thoughts
31 October 2007



Topics

- **What is the risk of raising state revenue share on the existing producing reservoirs?**
 - Look at AOGA, BP and other industry data
- **What are the goals or drivers for Alaska's Petroleum Fiscal System?**
 - List what we have discerned since arriving in Juneau
- **From a 50,000 foot viewpoint, what fiscal system structure accomplishes the above goals with a minimal need for intervention?**

The Tipping Point



Where is the tipping point?

- **Quite legitimately several legislators have asked their advisors and the companies how far is just right and how far is too far?**
 - The companies have complex decision making processes with many external factors at play and can't articulate what impact a change in Alaska taxes will have
 - Rock (Prospectivity) trumps Scissors (Fiscal) - Chevron
 - *Scissors (Fiscal) cut Paper (Profit)*
 - *Paper (Buy Reserves) covers Rock (Develop Reserves)*
 - Consultants acknowledge that taxes are but one of many factors that control decision making, and cannot say with certainty what tax rate is just right



Testing the Tipping Point

- **We can read lines, and between the lines, of industry testimony to construct a picture of the Alaskan investment climate**
 - AOGA letter which reflects “the full consensus of the members of the AOGA Tax Committee, with no dissent”
 - BP’s very detailed presentation on Prudhoe Bay area
 - Conoco’s useful insight on project economics
 - And other information supplied by Anadarko, Chevron, Exxon and Pioneer.
- **Details presented were then double checked against annual reports, SEC filings, analyst presentations and other company press releases where available**



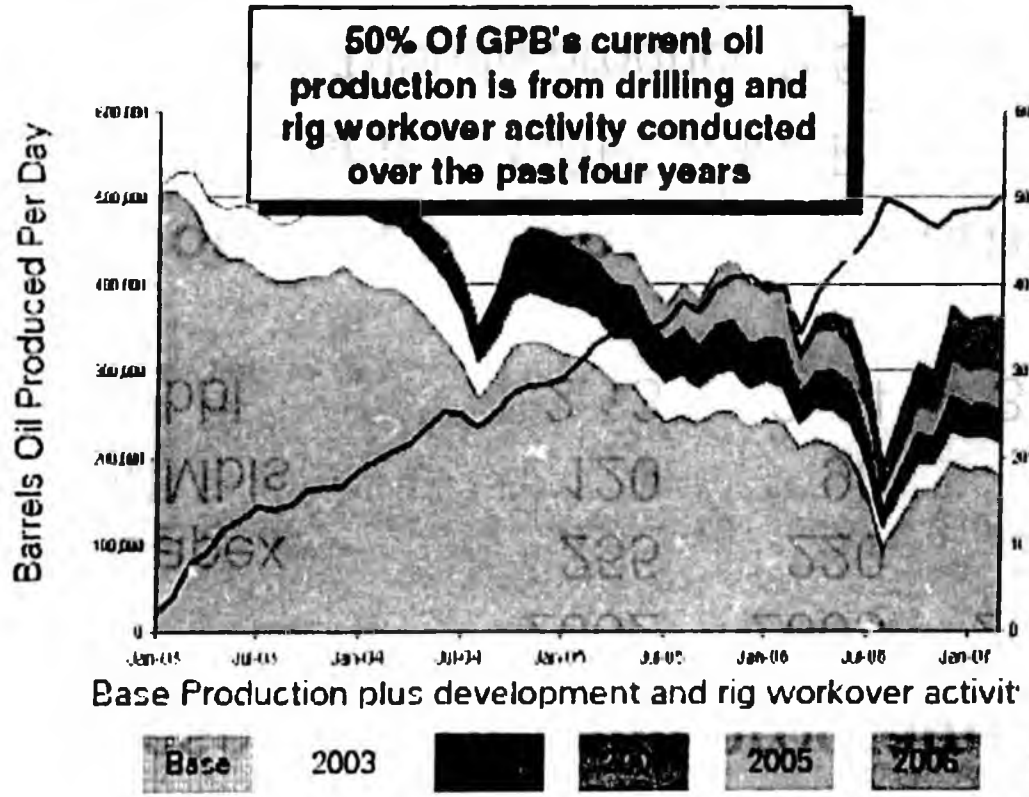
Overall Observations

- **We agree with industry that there is significant upside in reducing the decline from existing producing assets**
- **The economics of reinvestment in producing assets on the North Slope are extremely profitable**
 - Evaluated with actual costs, production and prices as reported by BP
 - Profitable even when tested against various stress points



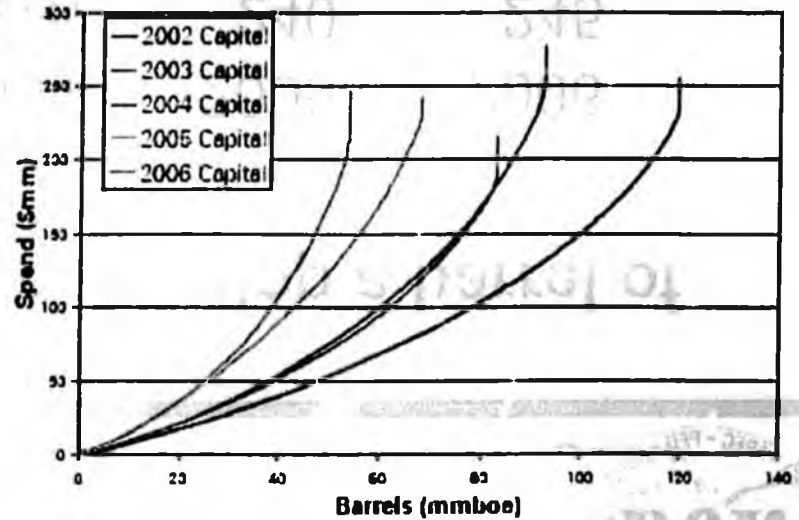
BP's infill drilling program

50% Of GPB's current oil production is from drilling and rig workover activity conducted over the past four years



Observations?

GPB Well Investments 2002-2006



BP House testimony page 12



Costlier Development

- It is getting more expensive to develop a barrel of reserves (BP Infill program)

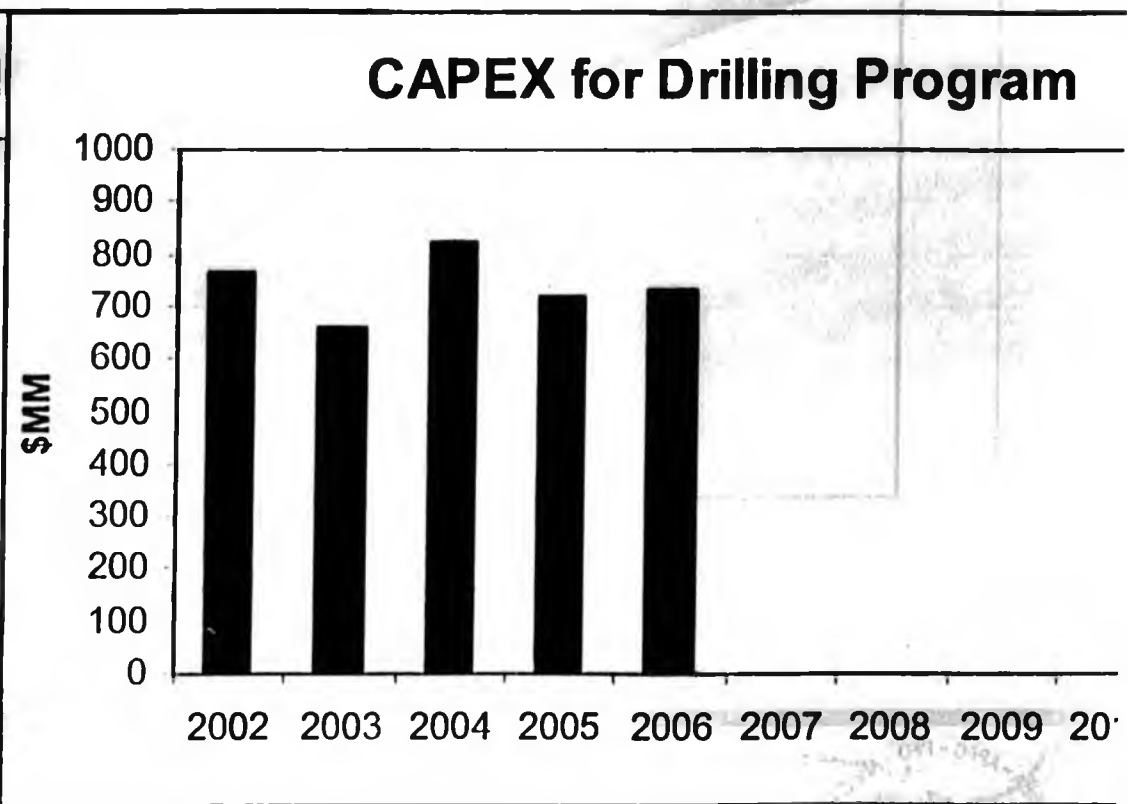
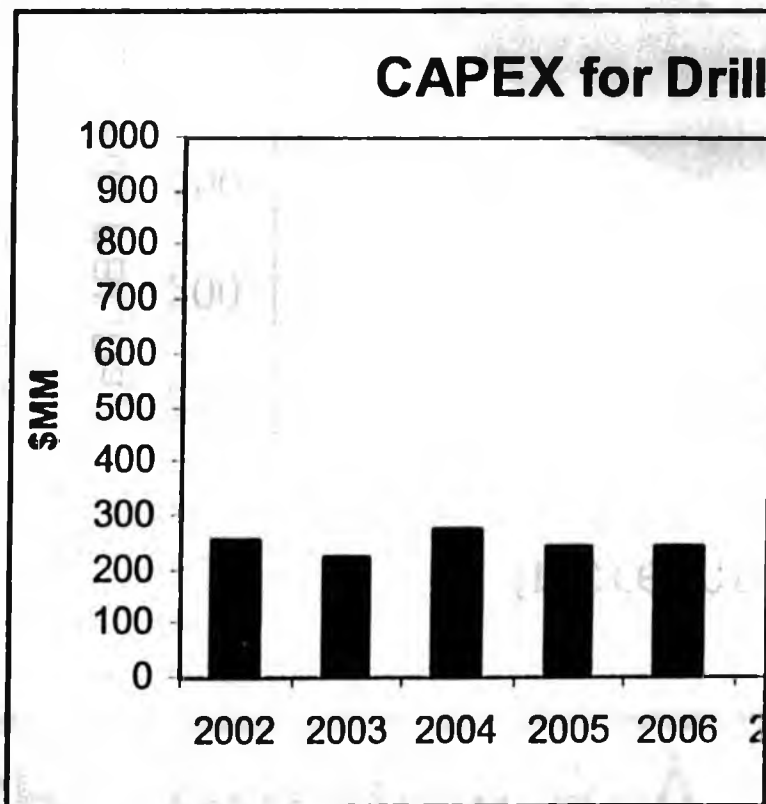
	2002	2003	2004	2005	2006
Capex	255	220	275	240	245
MMbbls	120	90	80	60	50
\$/bbl	2.13	2.44	3.44	4.00	4.90

- Contrast the above per barrel F&D costs with:
 - \$2 or less CAPEX for Prudhoe and Kuparuk to date
 - \$19bn to produce 9.5 bn bbls
 - The P/K upside at \$3.5(15%), \$7.7 (6%), \$12 (3%)
 - Pioneer's view of average F&D for Lower-48 of \$14



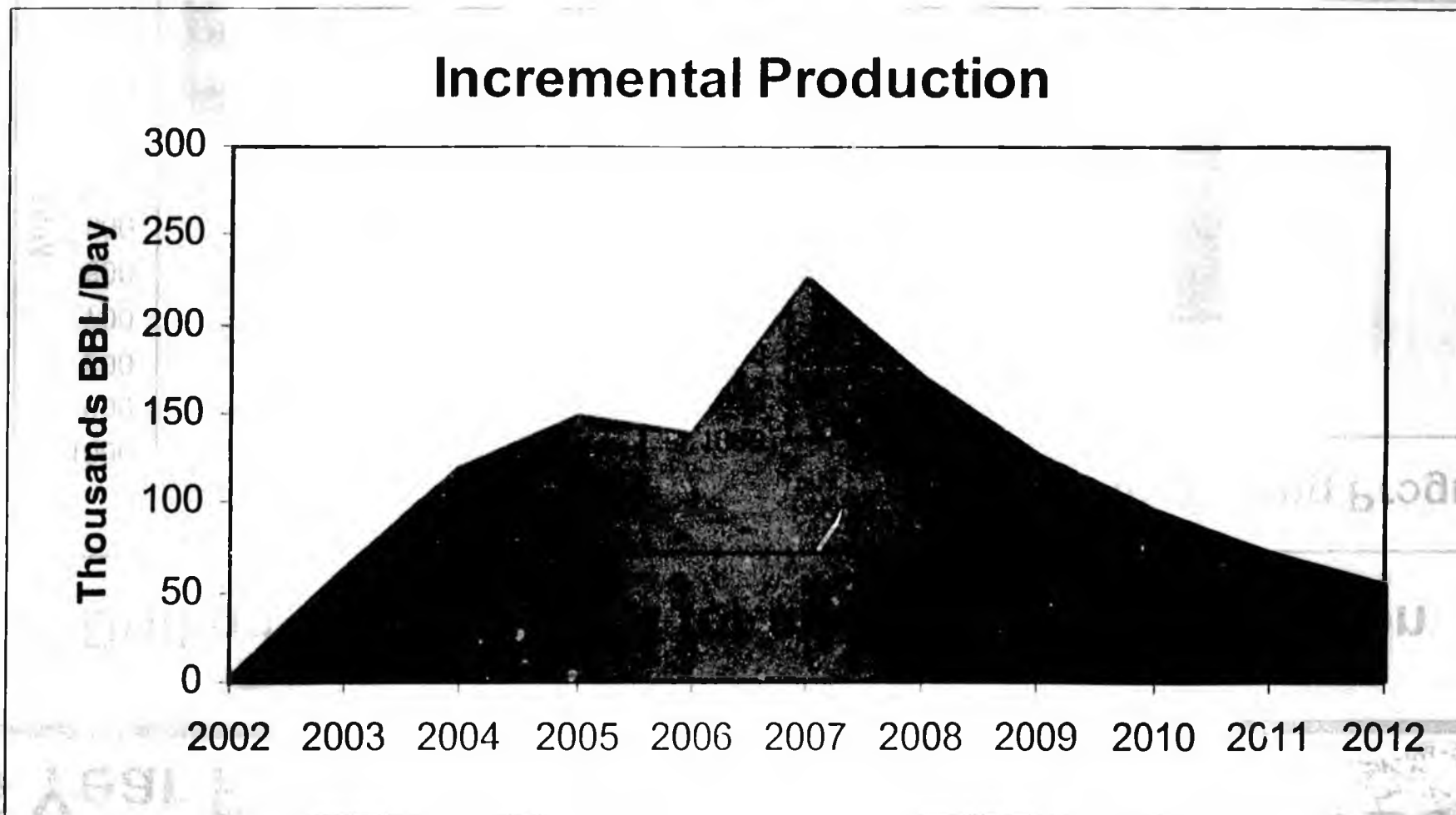
5 Year Prudhoe Drilling Program

- Drilling capex – 300% for added facilities/injection





BP – Prudhoe Bay



Revised from House version to fix plotting error
– underlying financial data/results are unaffected



Robust drilling program

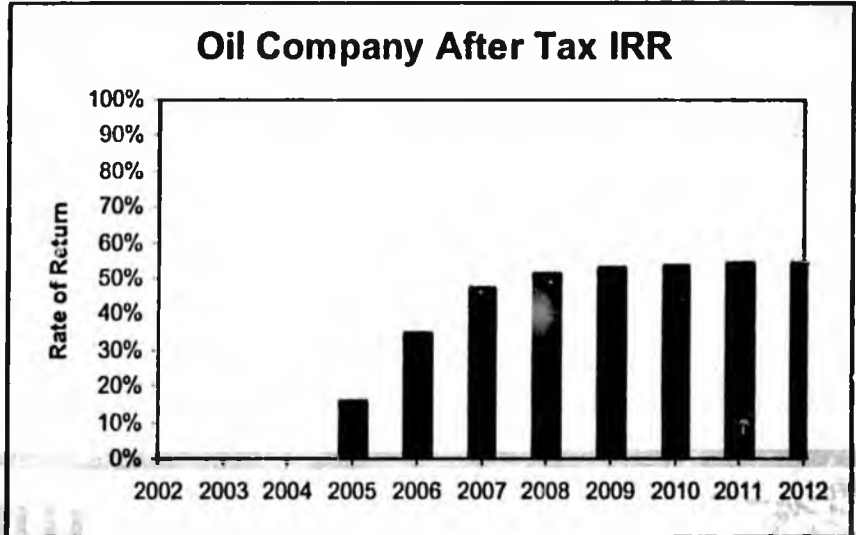
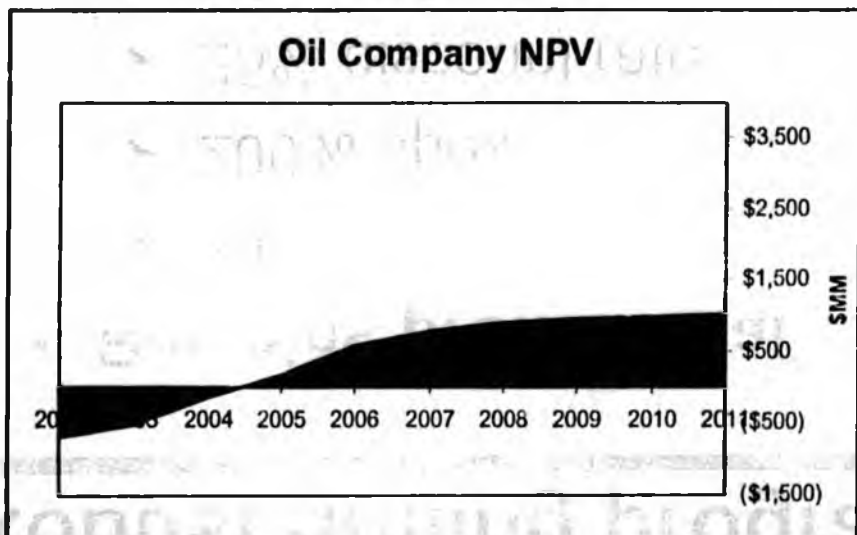
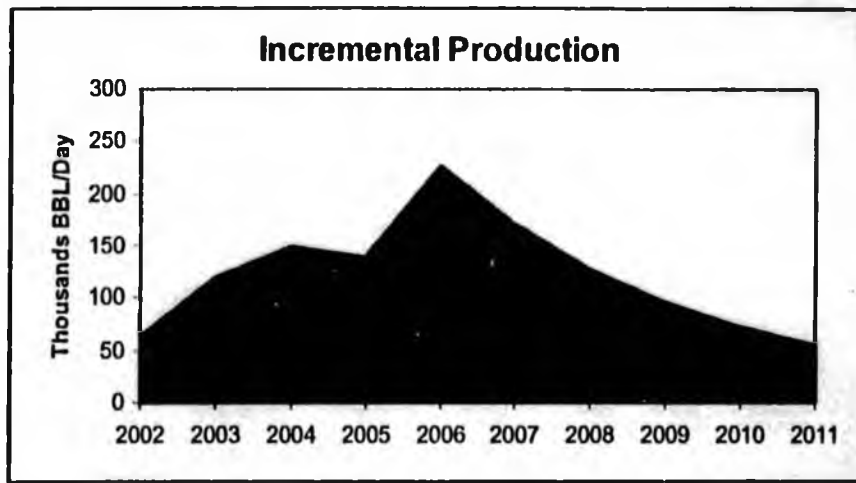
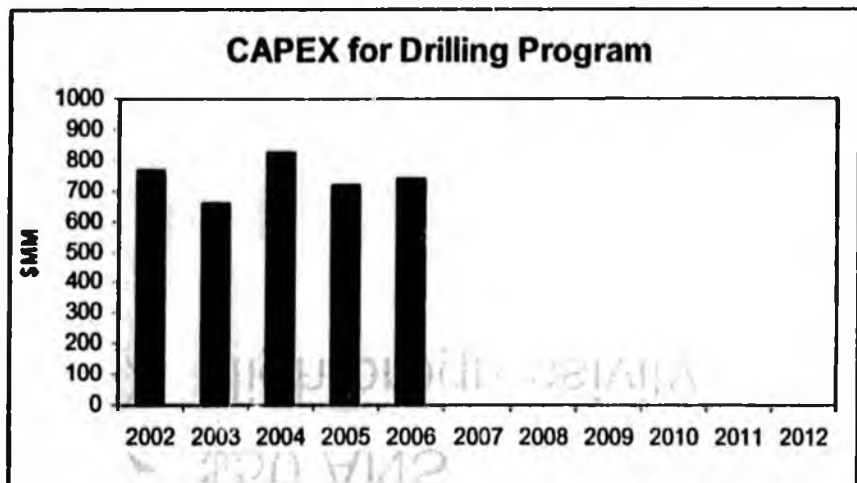
- **Remains profitable at:**
 - 300% capex
 - 200% opex
 - 25% discount rate
 - \$50 ANS
 - High progressivity

overly stressed case





Overly Stressed Case





Model Demonstration

- ▶ 520 000 per abandonment rate
- ▶ Used indicated decline rates and investments
- ▶ Built a generic model based on the above points

	2000	2005	2010
Industry Investment	22 bn	25 bn	27 bn
Produced Barrels	1.3 bn	3.3 bn	1.2 bn
Decline Rate	20%	20%	30%



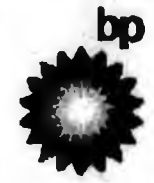
North Slope Potential





North Slope Potential

Production Drives Revenue



Decline Rate	15%	6%	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	\$5 bn	\$25 bn	\$70 bn
		Status quo	

- **Built a generic model based on the above barrels and investments**
 - Used indicated decline rates
 - 250,000 bpd abandonment rate



Under PPT

Production Drives Revenue



Decline Rate	15%	6%	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	\$5 bn	\$25 bn	\$70 bn
		Status quo	

- | | | | |
|-----------------|---------------|---------------|----------------|
| • NPV10 = \$Bn | • \$15 - \$20 | • \$30 - \$40 | • \$35 - \$45 |
| • NPV0 = \$Bn | • \$22 - \$27 | • \$55 - \$75 | • \$90 - \$125 |
| • NPV0 = \$/bbl | • \$15 - \$20 | • \$14 - \$19 | • \$12 - \$17 |

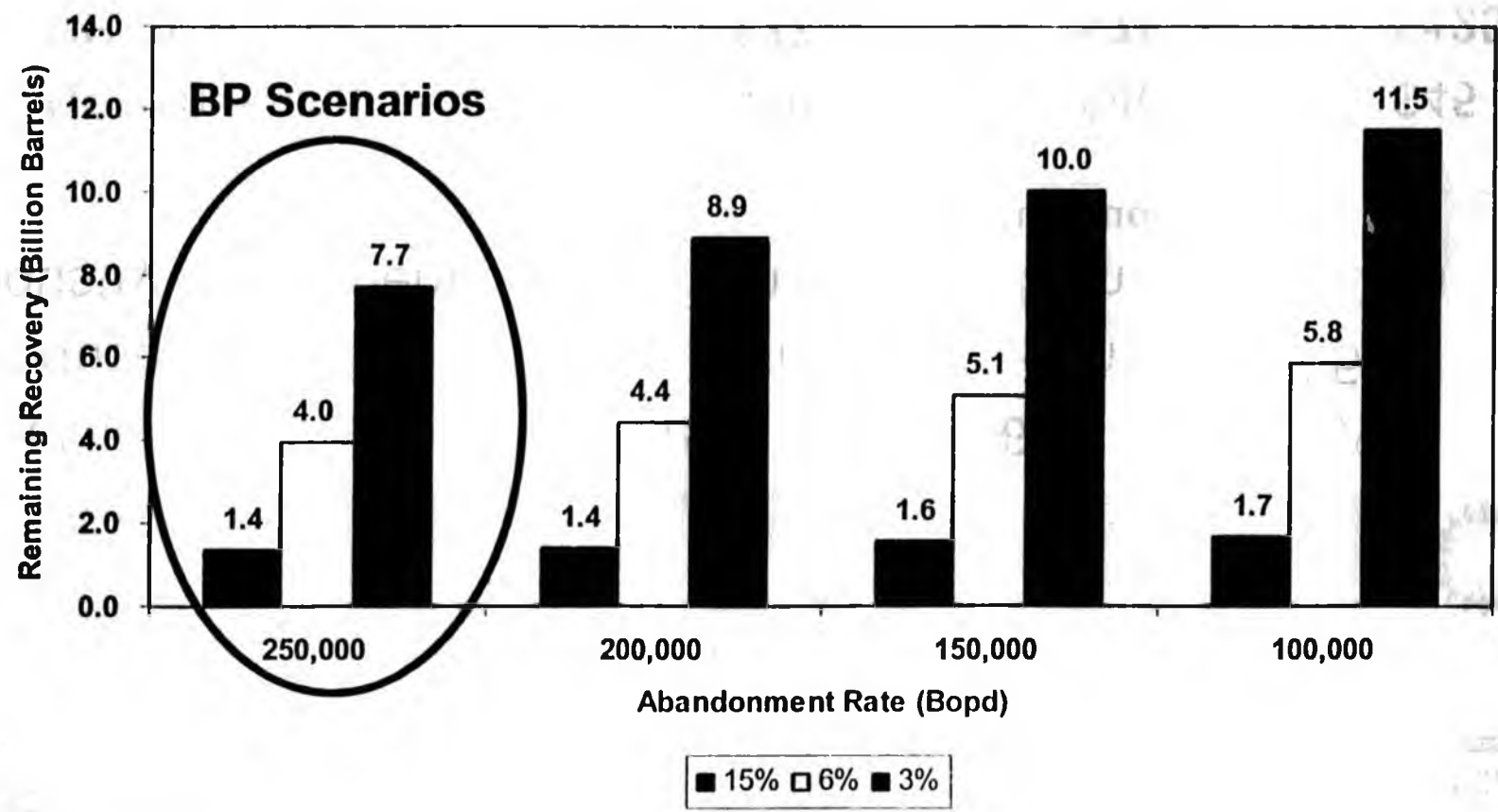
~ \$80/bbl WTI, \$70/bbl NS





North Slope Abandonment

Impact Of Abandonment Rate On North Slope Recovery



Summary

... about future
 ...
 ...
 ... as soon as possible - I ...

analyst growth expectations

If the production volumes associated with the 6% and 3%

Goals

... on booked as proved
 ... the continuing investments
 ...

• Drilling program is so profitable that under even the most
 extreme net tax structure, oil companies would want to
 continue their reinvestment program.



Goals for Fiscal Design

- **Based on hearings, discussions and other dialog we (GCA) see the following as the goals you are trying to achieve in this special session:**
 1. Fields with larger **profitability** should be paying more taxes
 2. Encourage investment in existing units
 - Reinvestment in producing assets
 - Investment in new developments
 - ❖ Conventional
 - ❖ Unconventional (i.e. heavy oil)
 3. Encourage new investment outside legacy units
 - Level playing field for incumbents and new entrants
 4. Durability
 - Don't want to be back 'fixing' things
 5. Build on prior tax dialogue



(3) Encourage New Investment

- **Fiscal system should encourage investment in new fields**

*Mr. Ruggard
"One of best encourage
new investment"*

- Investment credits
- Net Operating Loss credits
 - Aid to new entrants with no existing tax base
- Lower tax rate for fields with higher cost structure
 - More distant from infrastructure
 - Heavy Oil
 - Gas

- **Is base rate low enough?**

Extends Life of TAPS

- Additional barrels down TAPS extends production from existing reservoirs



The Fiscal Design Challenge

- **The Take**

- (1) Fair share of the high margins currently being realized
- Progressive structure to adapt to changes in:

- Price
- Production
- Cost

3/29 57001

- **The Give Back**

- (2) Encouragement to reinvest profits for more development inside legacy units



Key Point Easily Misunderstood

- Development inside projects
- (5) Focus on development to achieve higher quality
- THE GIVE BACK

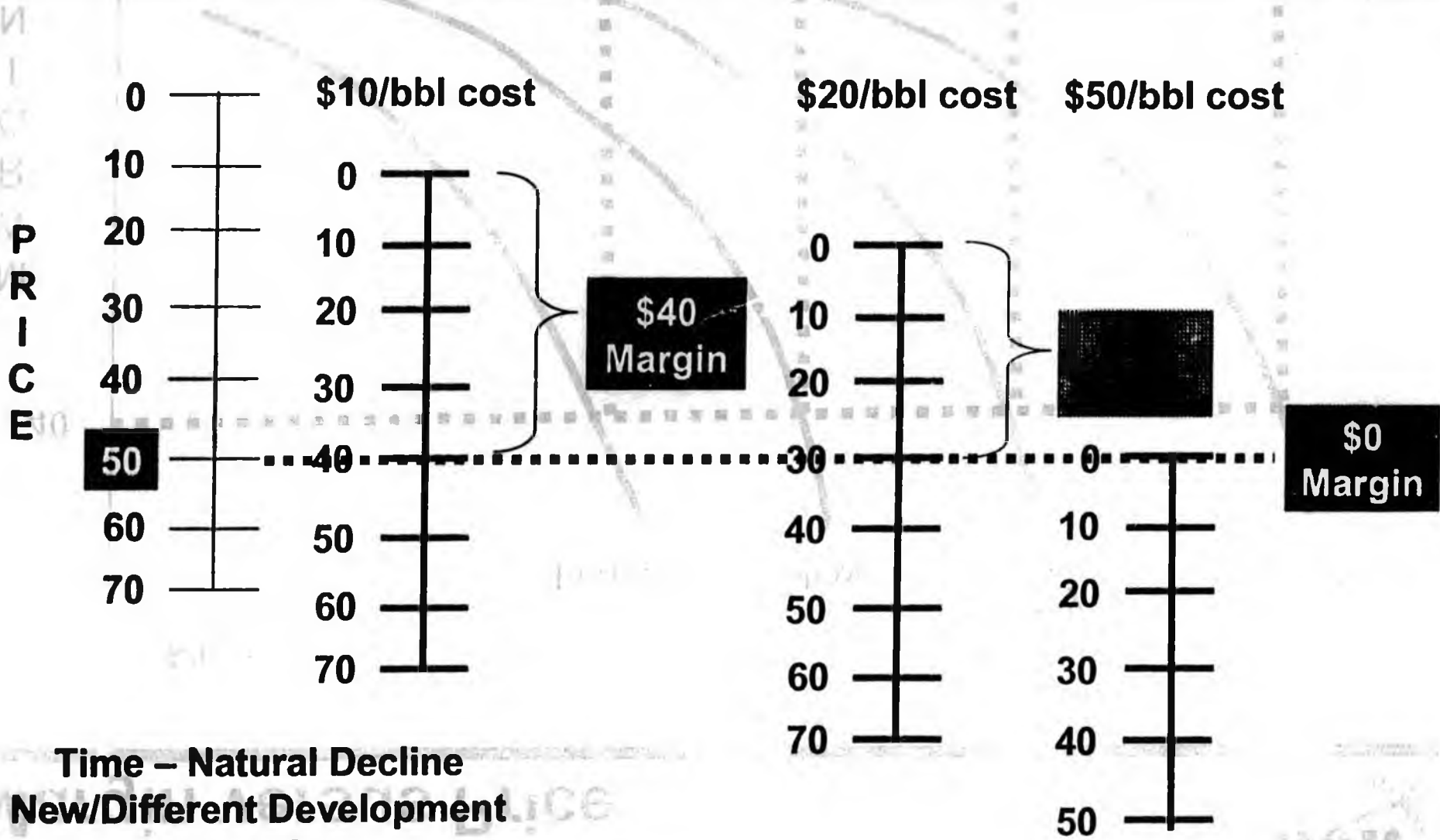
Price \neq Margin

- Price is not the same as margin
- Margin is the difference between price and cost
- Price is what you pay for a product or service
- Margin is what you keep after paying for the cost of the product or service

THE BIGGEST DESIGN CHALLENGE



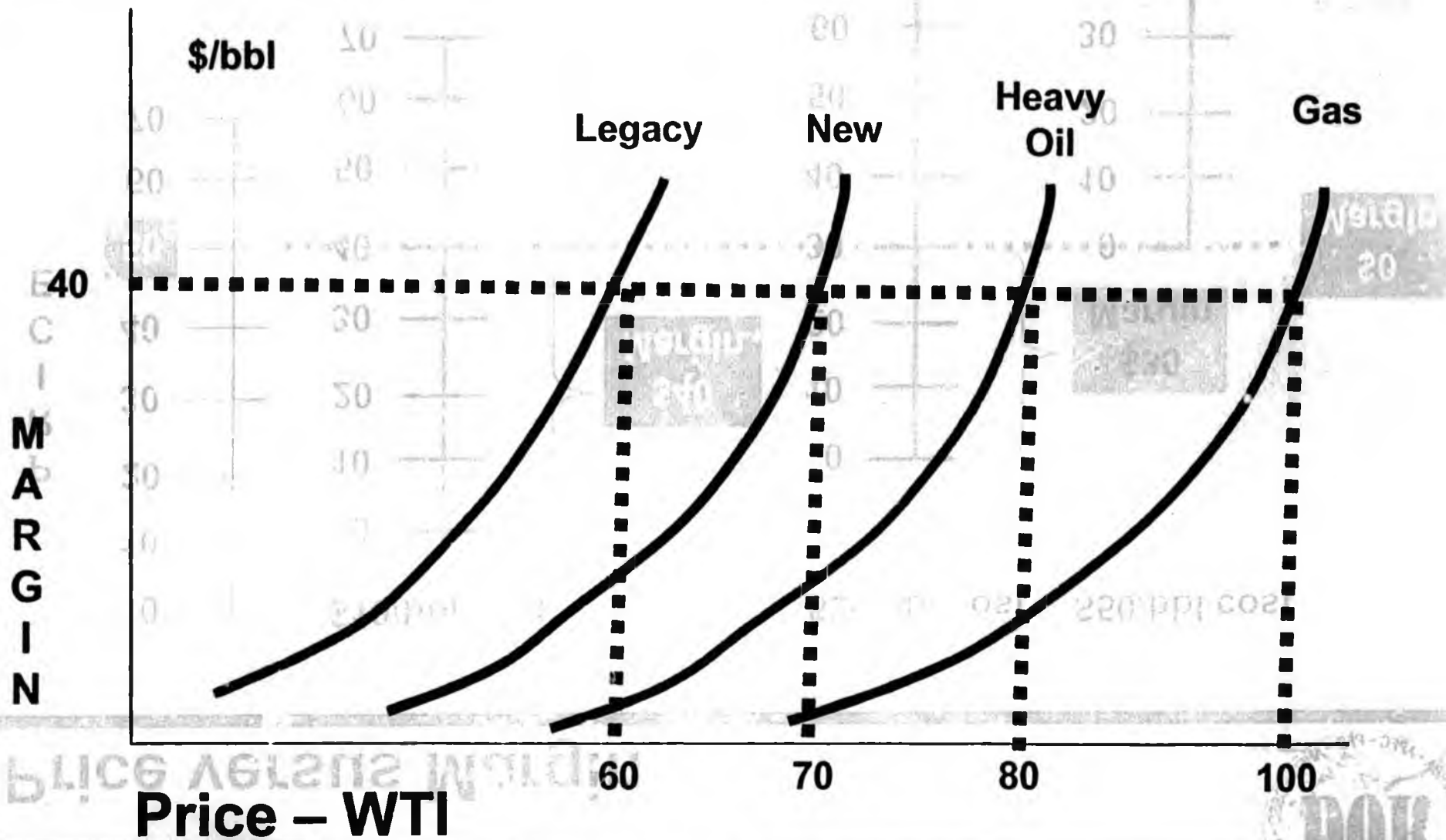
Price versus Margin



Time – Natural Decline
New/Different Development
Oil vs Gas

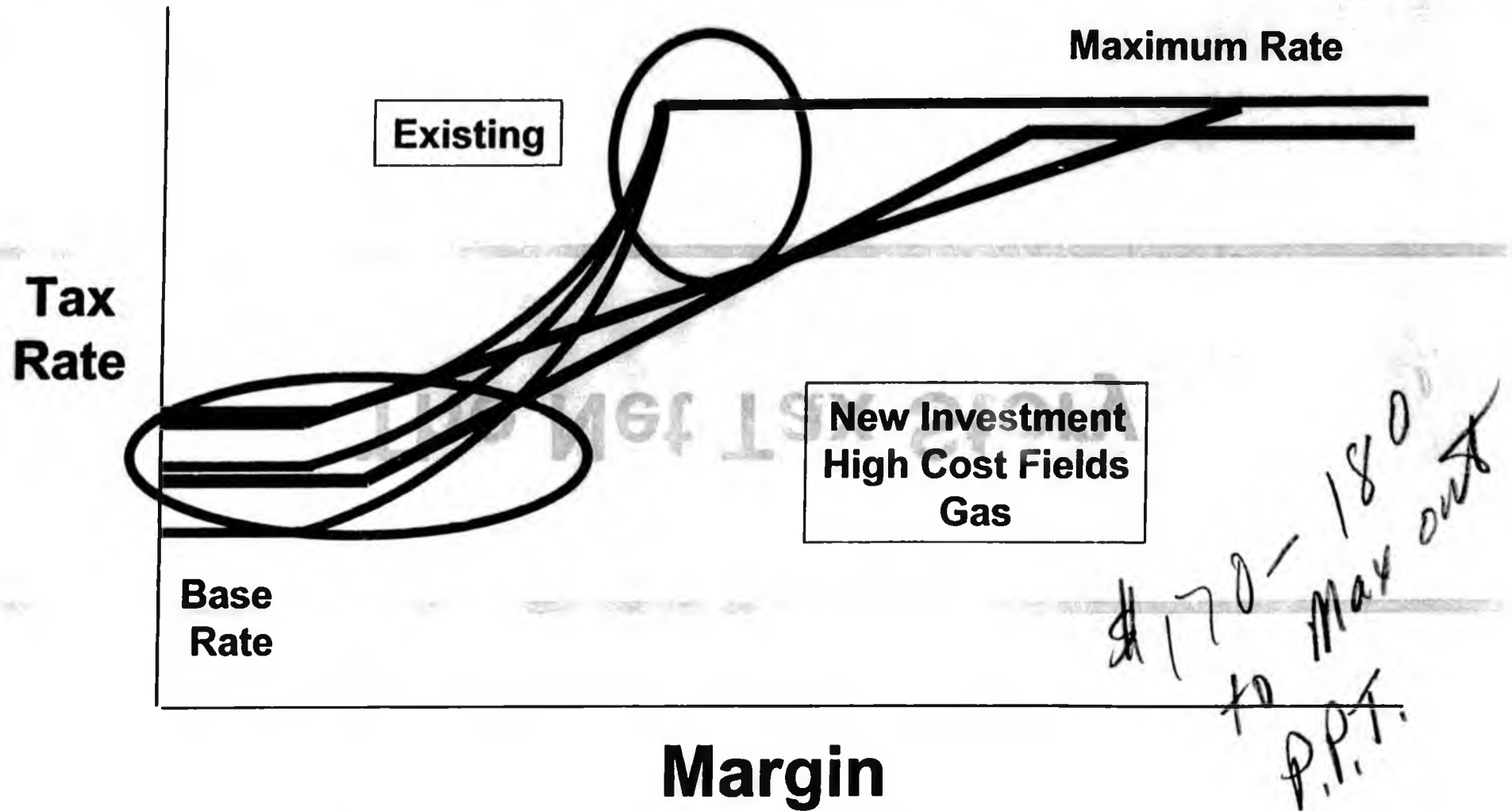


Margin versus Price





Pulled Into a single mechanism



Margin

57%
10/1/01
1/1/02
4/1/02

Rate

Rate

Rate

High Cost Fields

The Net Tax Story

Rate
TAX

EXTENDING

MAXIMUM RATE

Pushed into a single mechanism





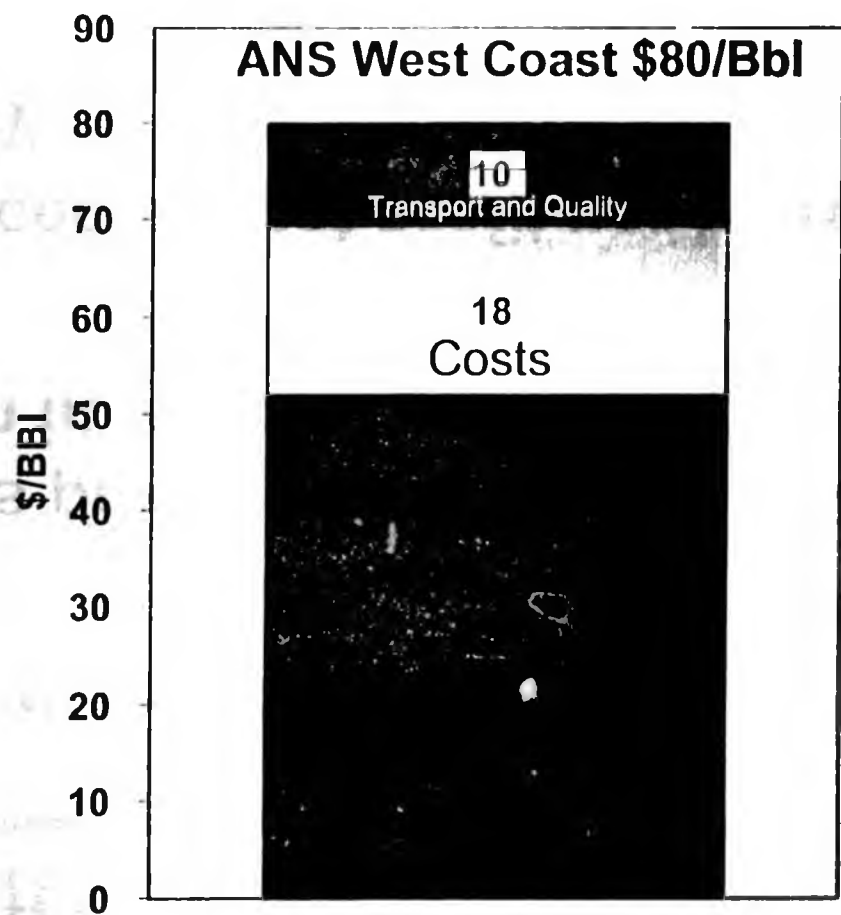
PPT As Often Described

- Tax on net profits
- Contains progressivity feature that increases tax rate with increasing profitability per barrel
- Ringfenced so that profit per barrel reflects a company's entire portfolio



The Information Used

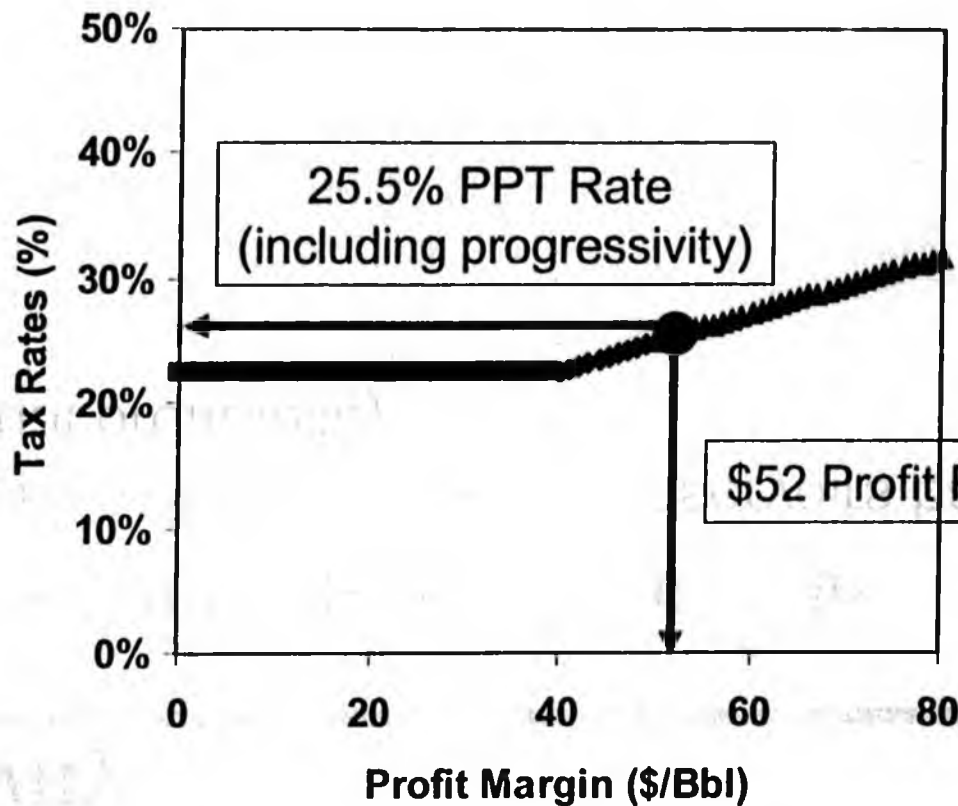
Portfolio Profitability





Based On \$52/Bbl Profit ...

Tax Rate Structure (Incorporating Progressivity)

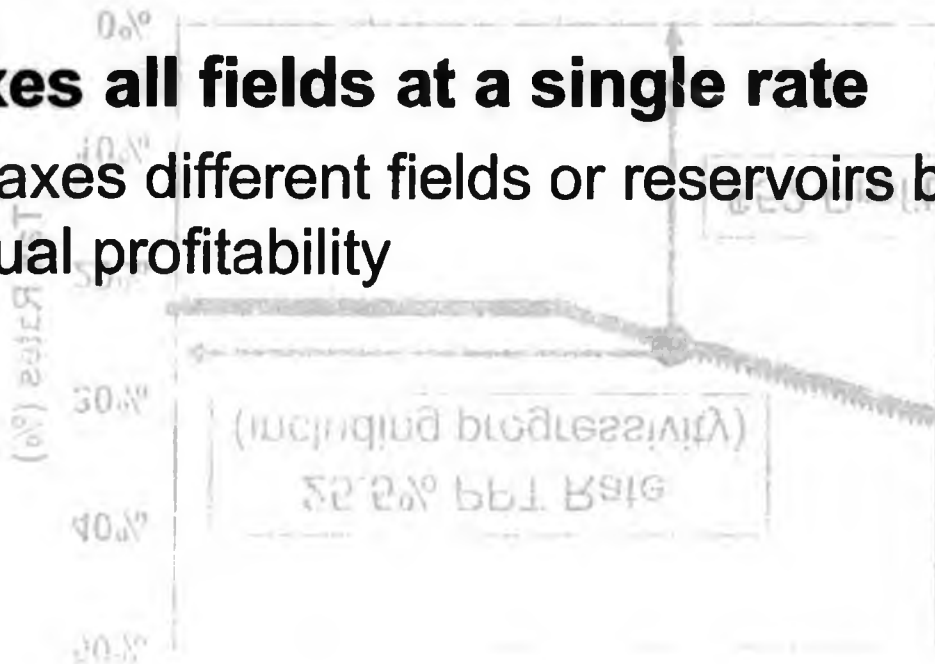




Progressivity

Profit Margin (\$\backslash\$PPI)

- **“Net” taxes all fields at a single rate**
 - No, it taxes different fields or reservoirs based on their individual profitability

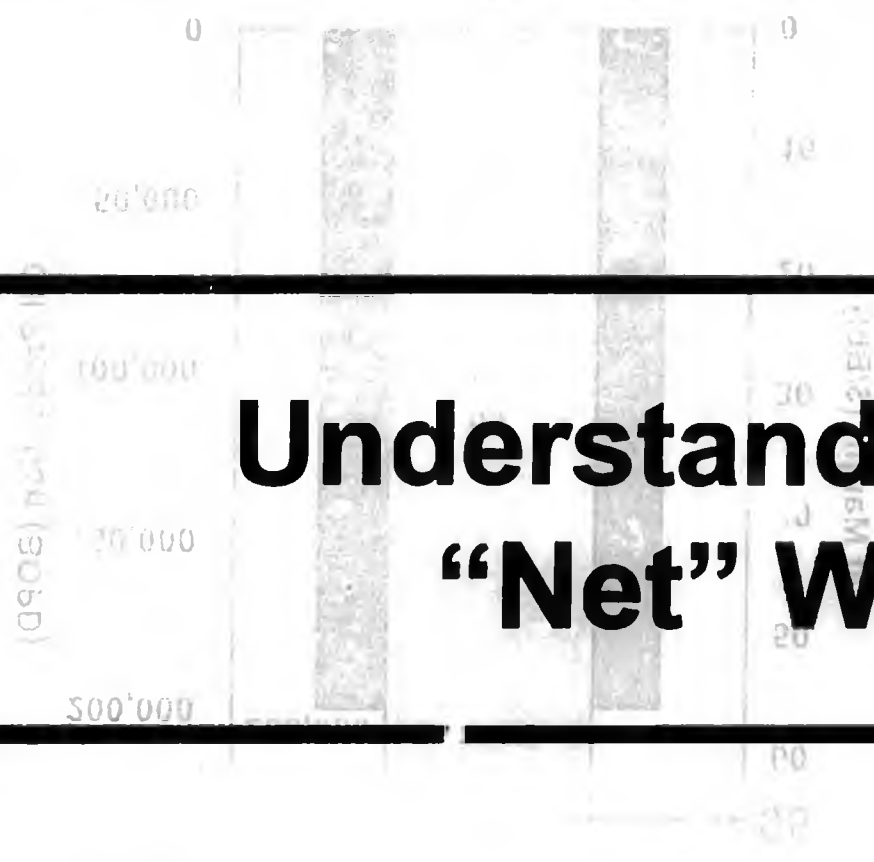


(including progressivity)
32.5% PPT Rate

Based on \$\backslash\$PPI Profit



Existing Reservoirs



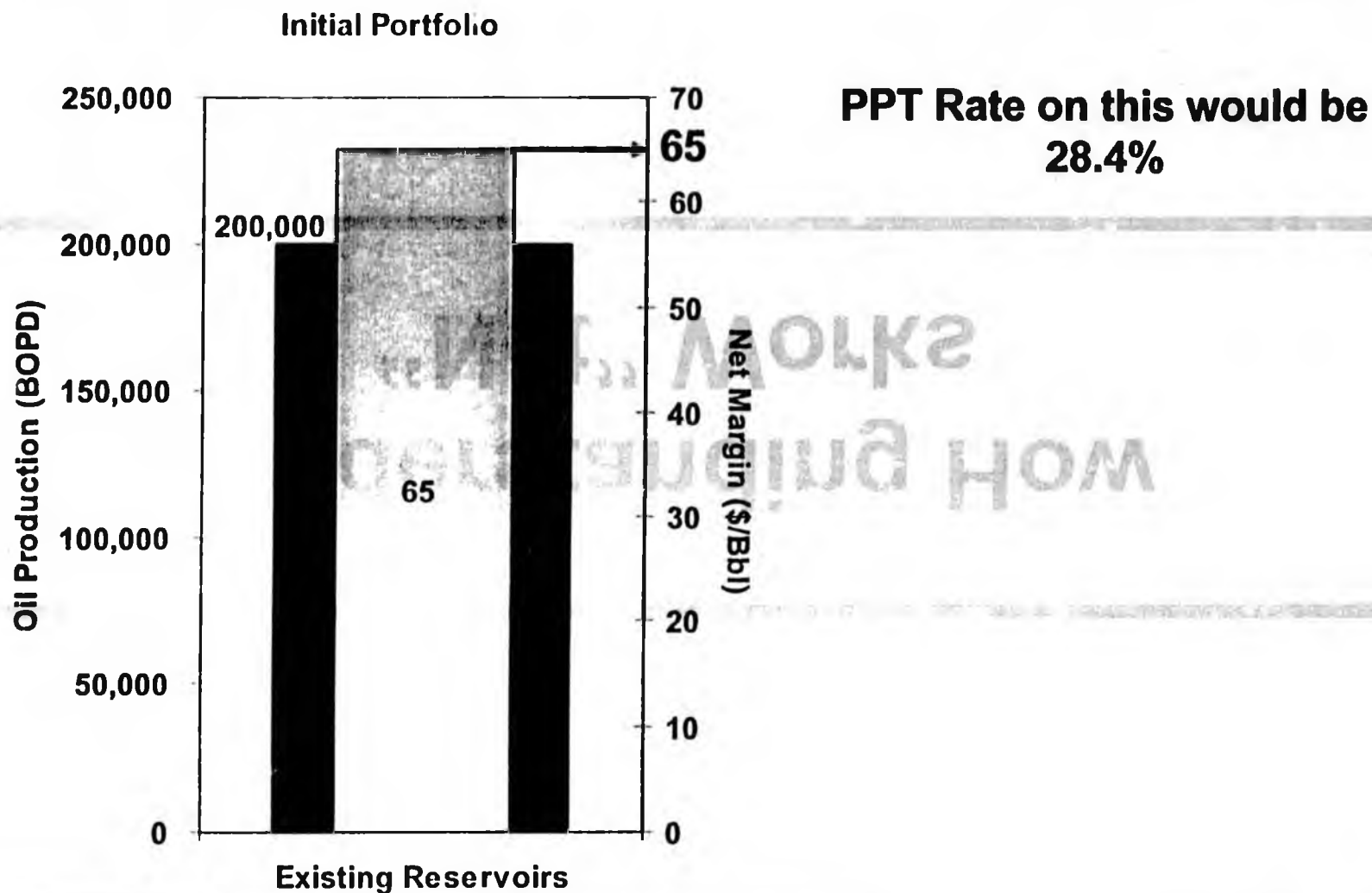
Understanding How "Net" Works

Start with a portfolio of long investment





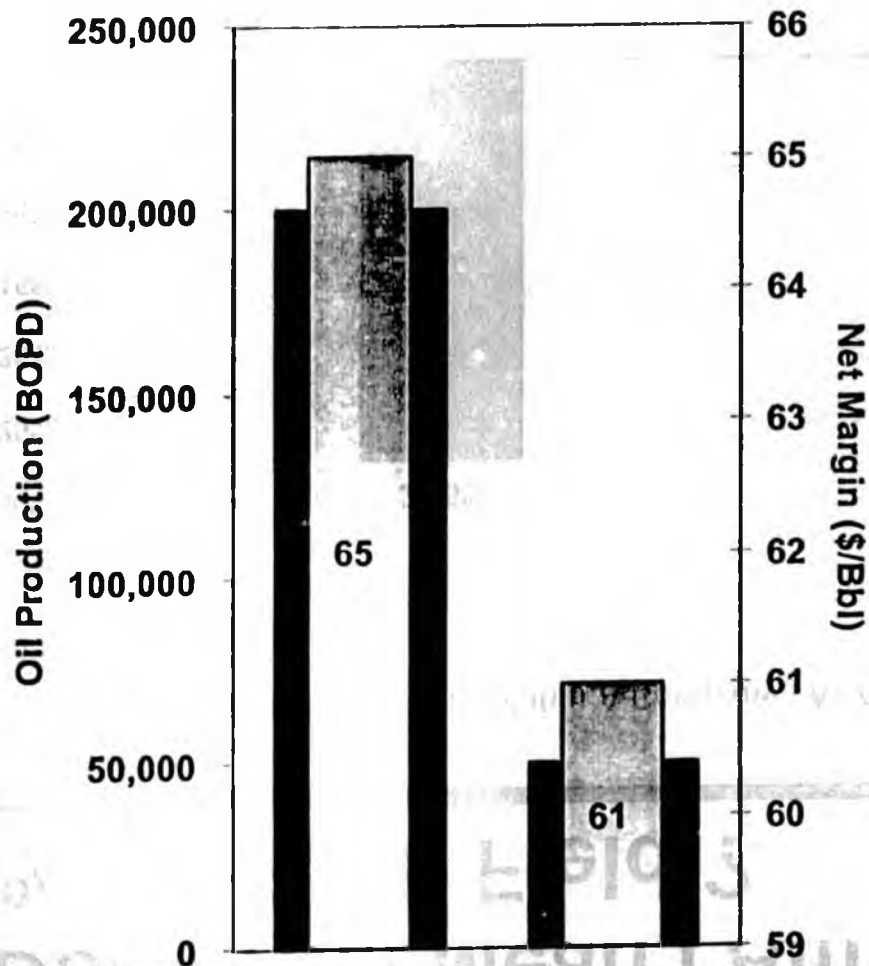
Start With A Portfolio Of One Investment





Now, Add Another Field

Expanded Portfolio



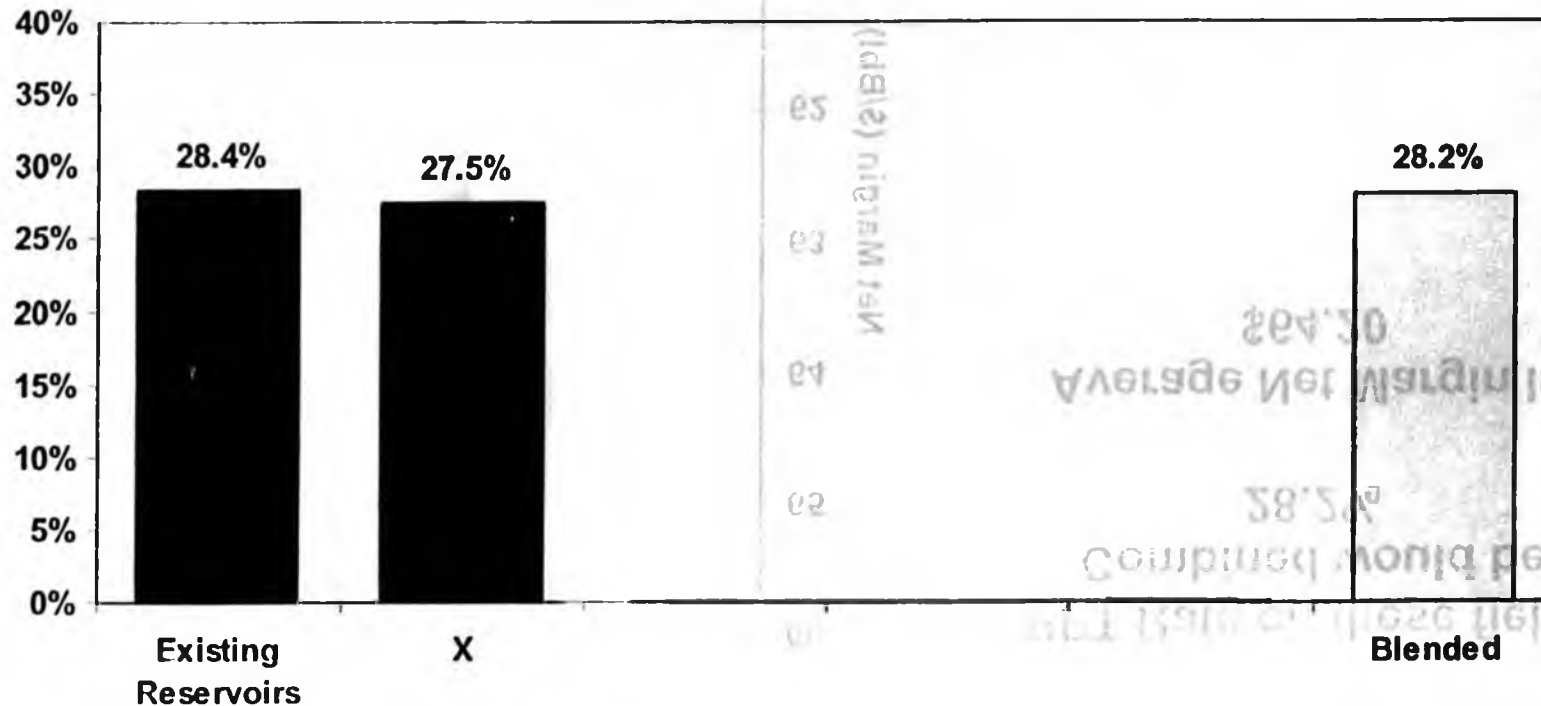
**PPT Rate on these fields
Combined would be
28.2%**

**Average Net Margin Is
\$64.20**

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



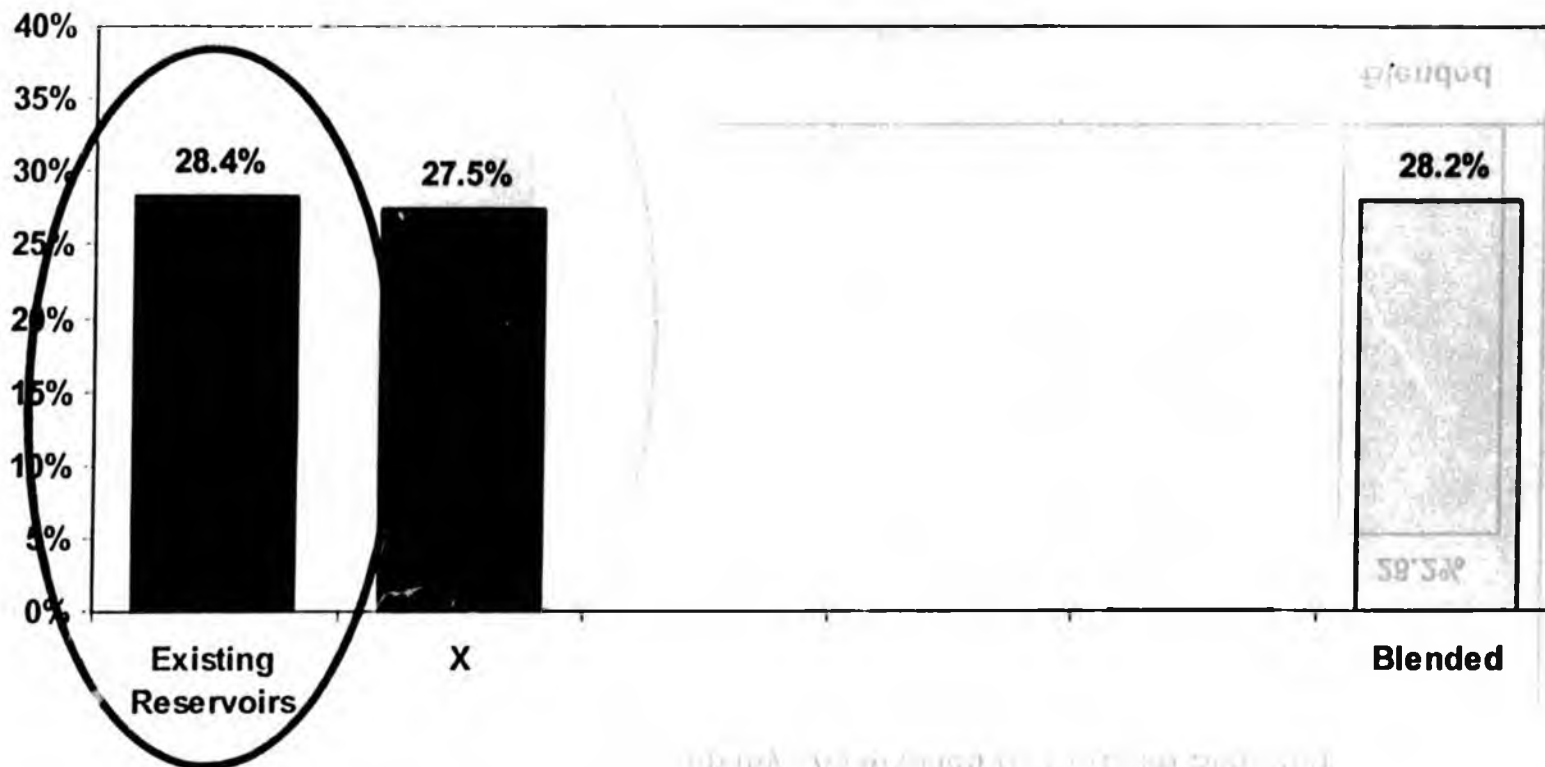
No

Look at this in the way that companies look at it when they make investment decisions

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

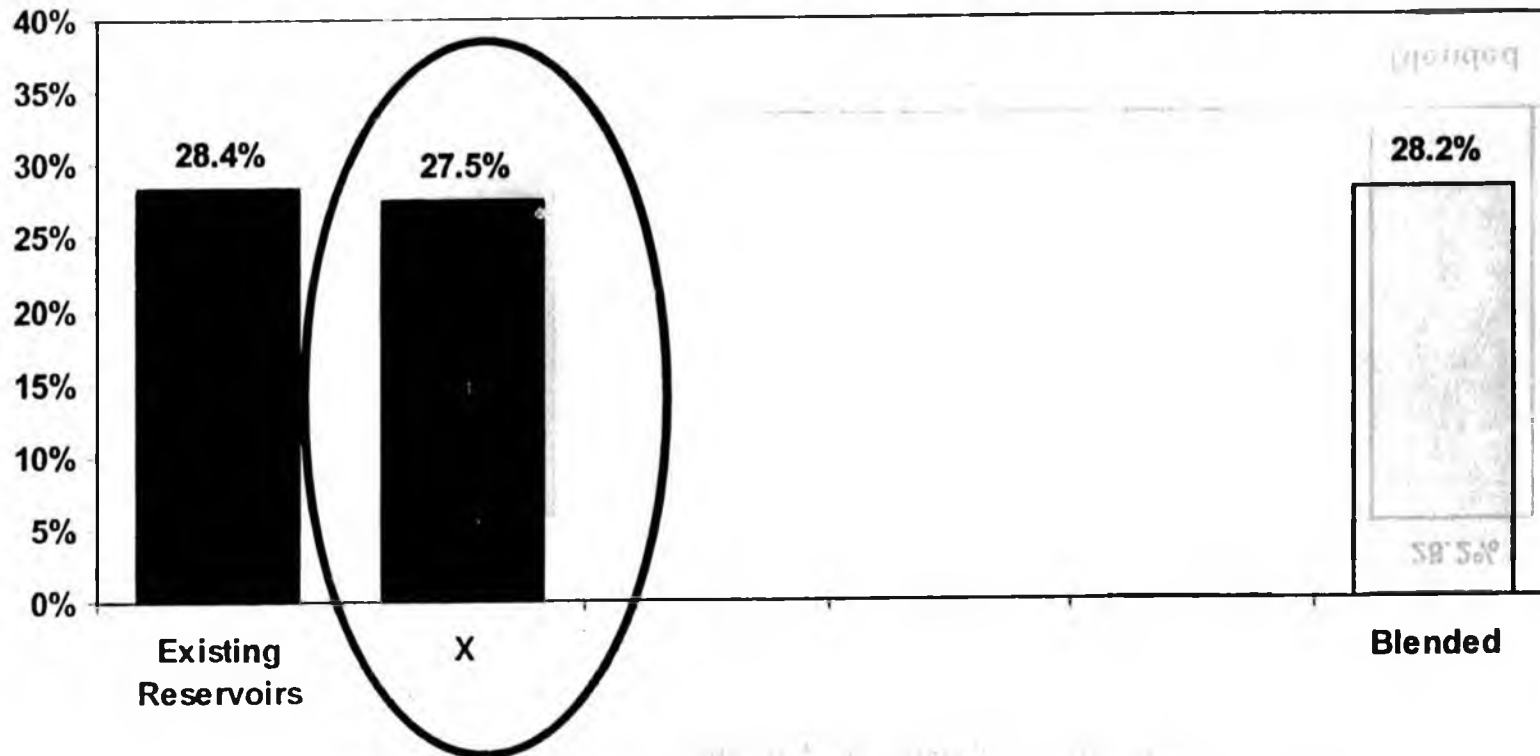


If I had just Existing Reservoirs, and did not develop anything new, I would pay tax on my profits at 28.4%

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

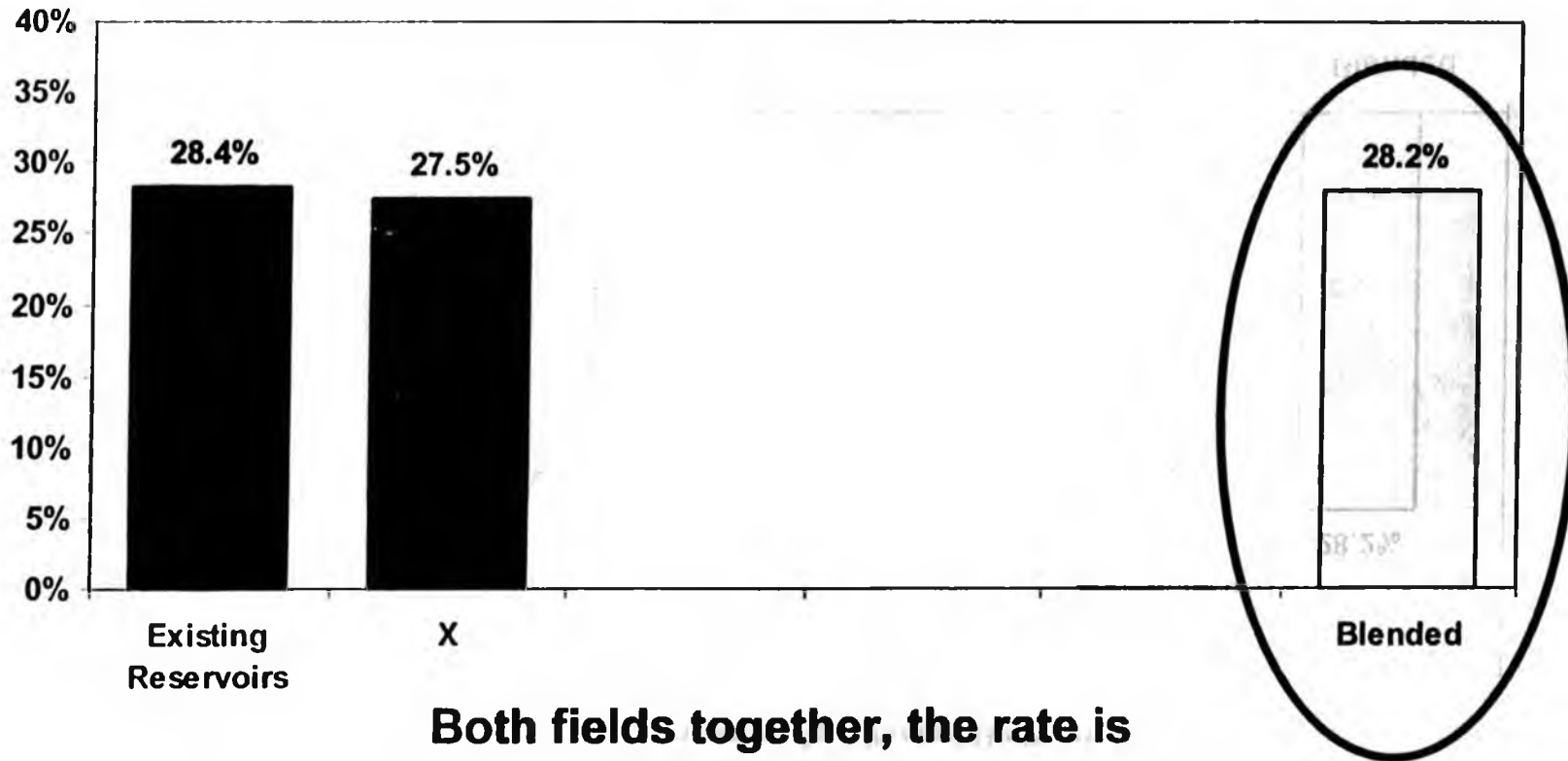


If I had just Field X, I would pay tax on my profits at 27.5% - its margin is slightly lower

So, Does That Mean I Am Paying 28.2% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



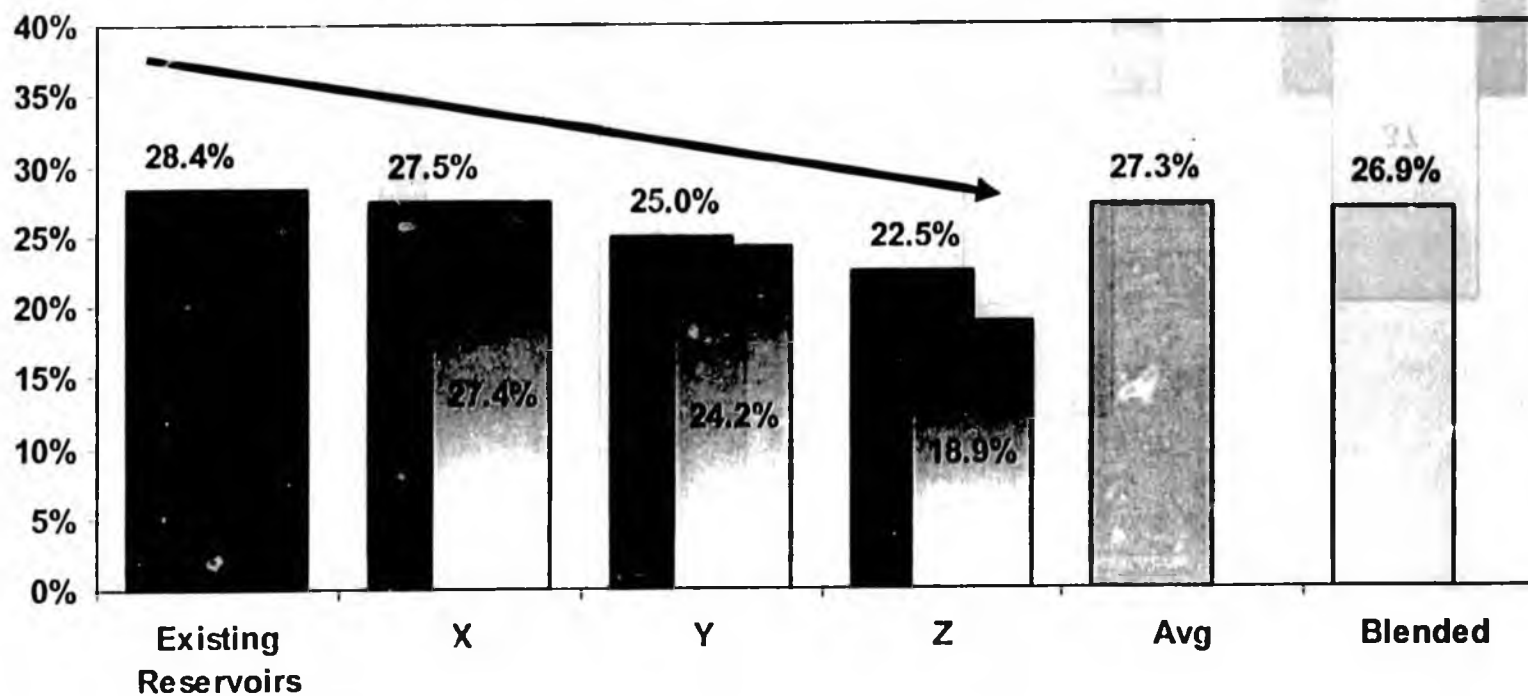
Both fields together, the rate is 28.2%

However, this is not all ...

The Impact On The Lower Margin Fields Is More Noticeable



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

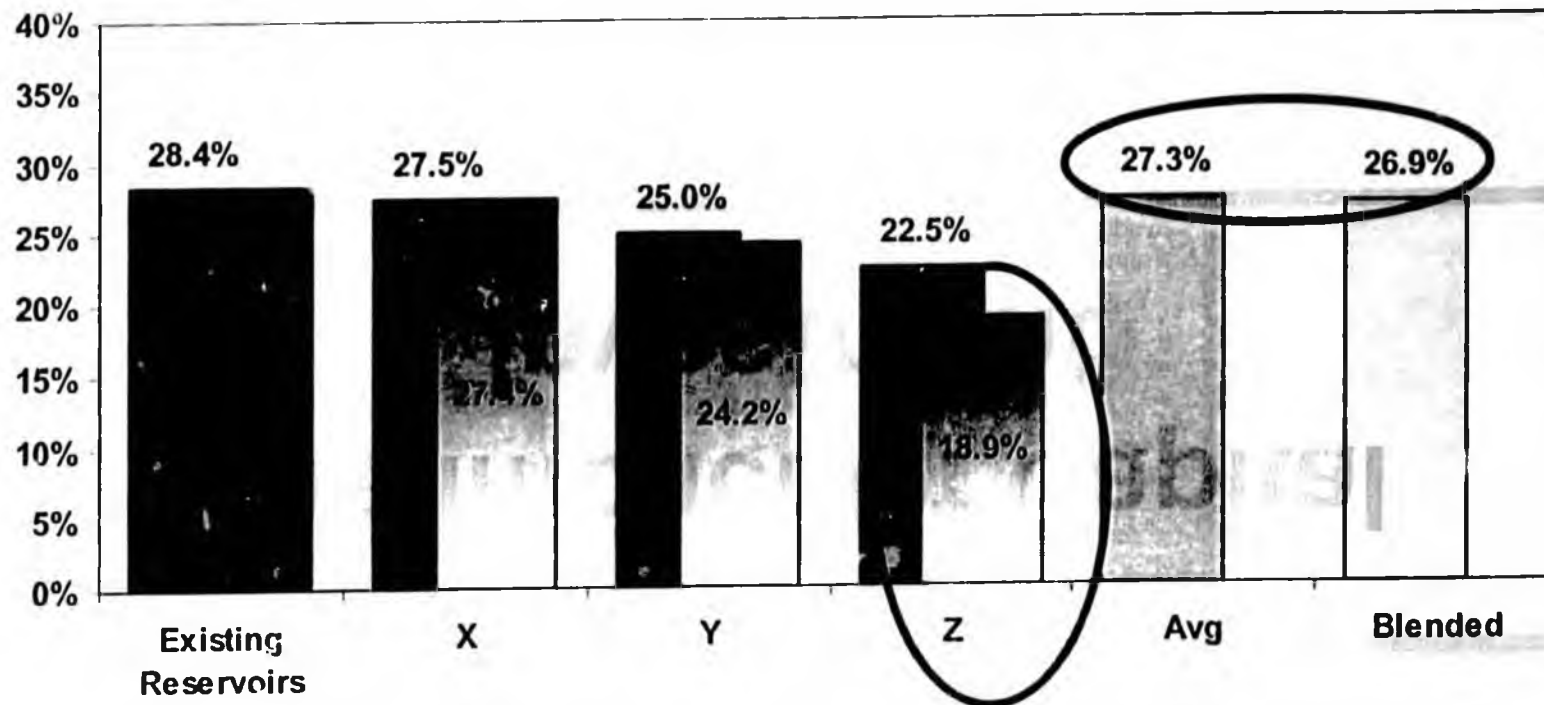


The progressivity can be seen through the lower effective tax rate on lower margin fields

The Impact On The Lower Margin Fields Is More Noticeable



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



The effective rate on some lower-margin fields may even be lower than the basic rate (22.5% in PPT)

This is manifested in the blended rate being lower than the weighted average rate

weighted average rate

This is manifested in the blended rate being lower than the
rate from the bond...
The... rate... will... over...

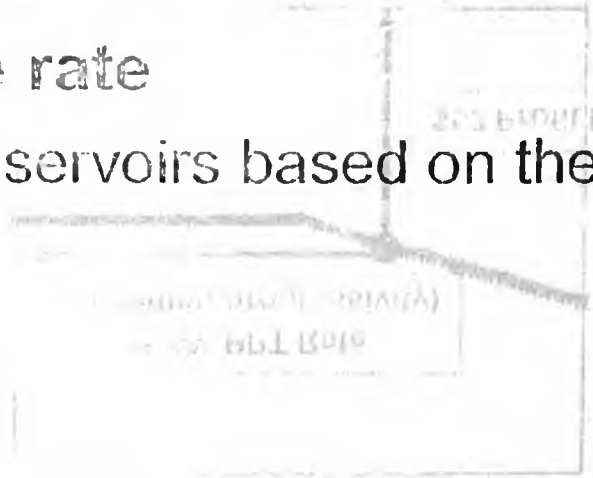
The Impact Of Capital Investment





Cash Flow, Not Profit

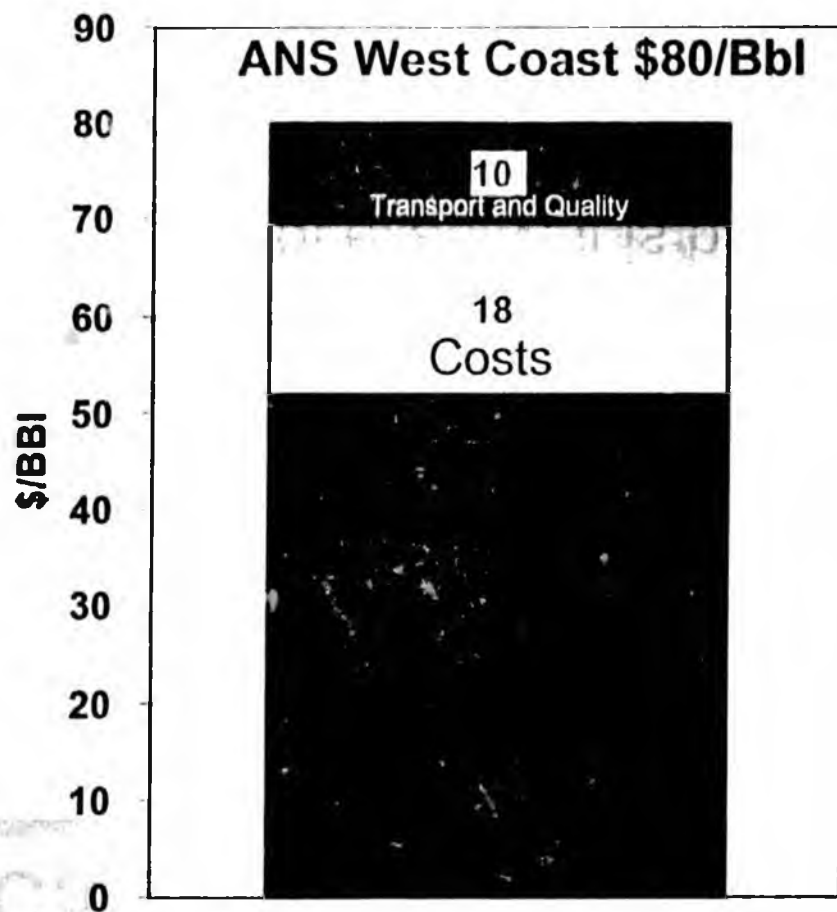
- **PPT taxes all fields at a single rate**
 - No, it taxes different fields or reservoirs based on their individual profitability
- **Is based on profit per barrel**
 - Not exactly, it is based on net cash flow per barrel after capital investment (for future production)





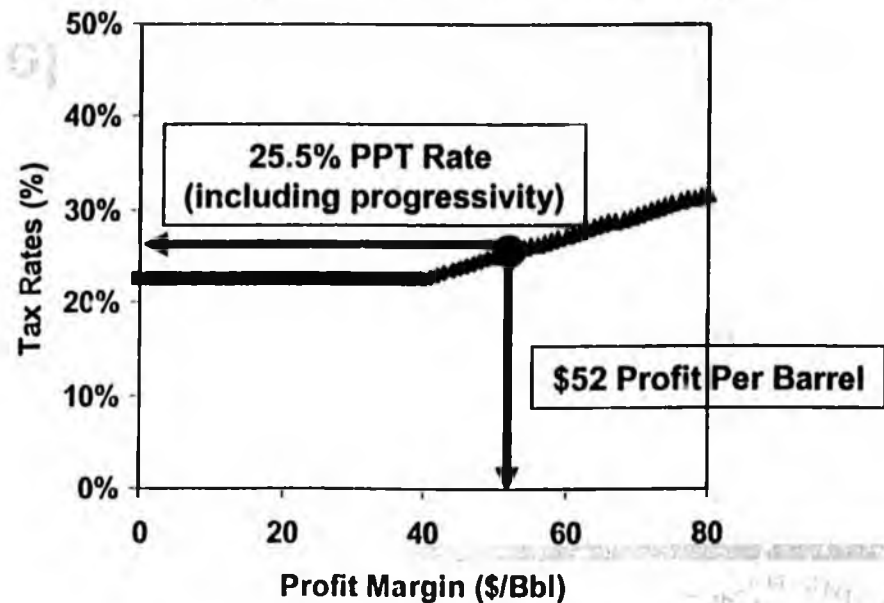
Remember These Slides ?

Portfolio Profitability



The portfolio on the previous slides had a blended rate of 26.9%, not 25.5%

Tax Rate Structure (Incorporating Progressivity)



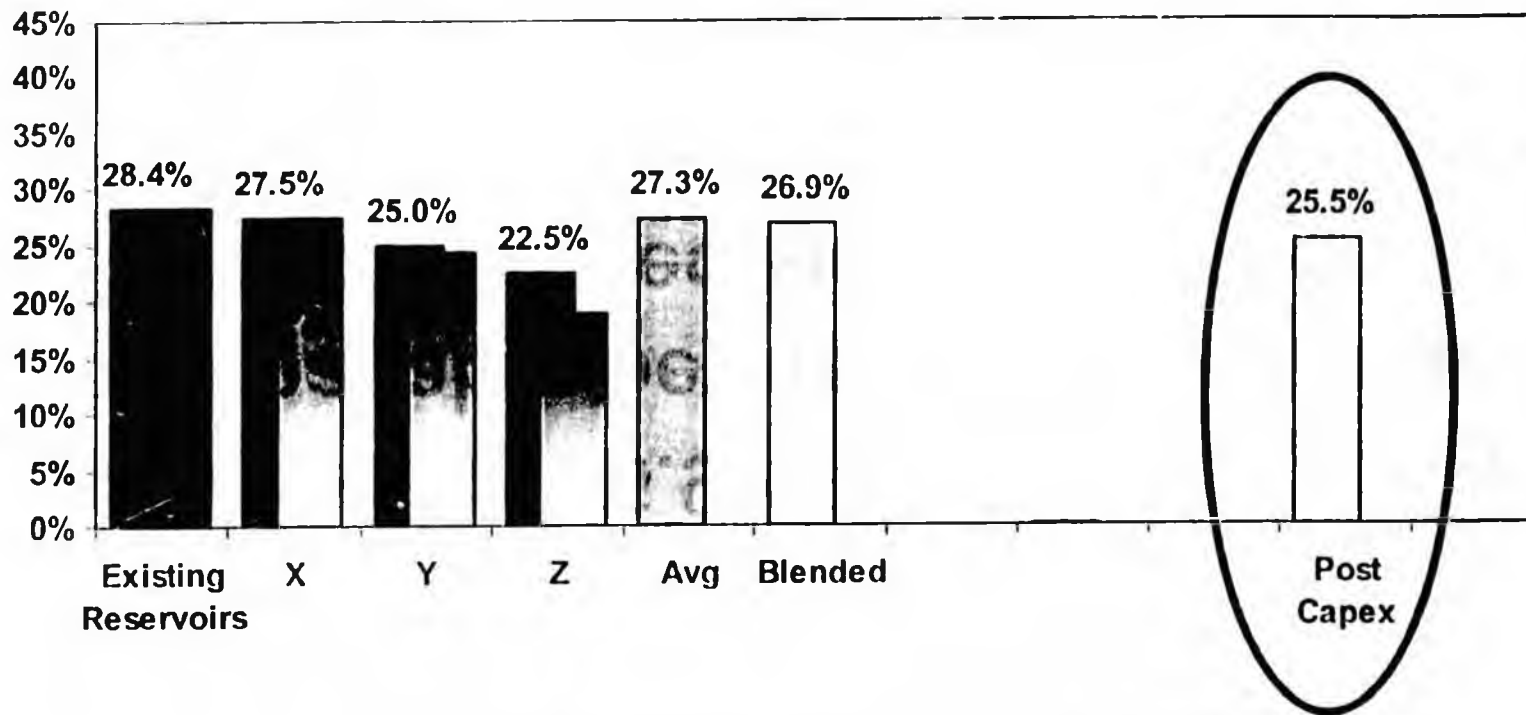
**Assume that 26.9% is the rate that will
be payable before further capital
investment decisions are made ...**

... in this example \$800 million

Capital Spending Has An Impact On Rate, Too



Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



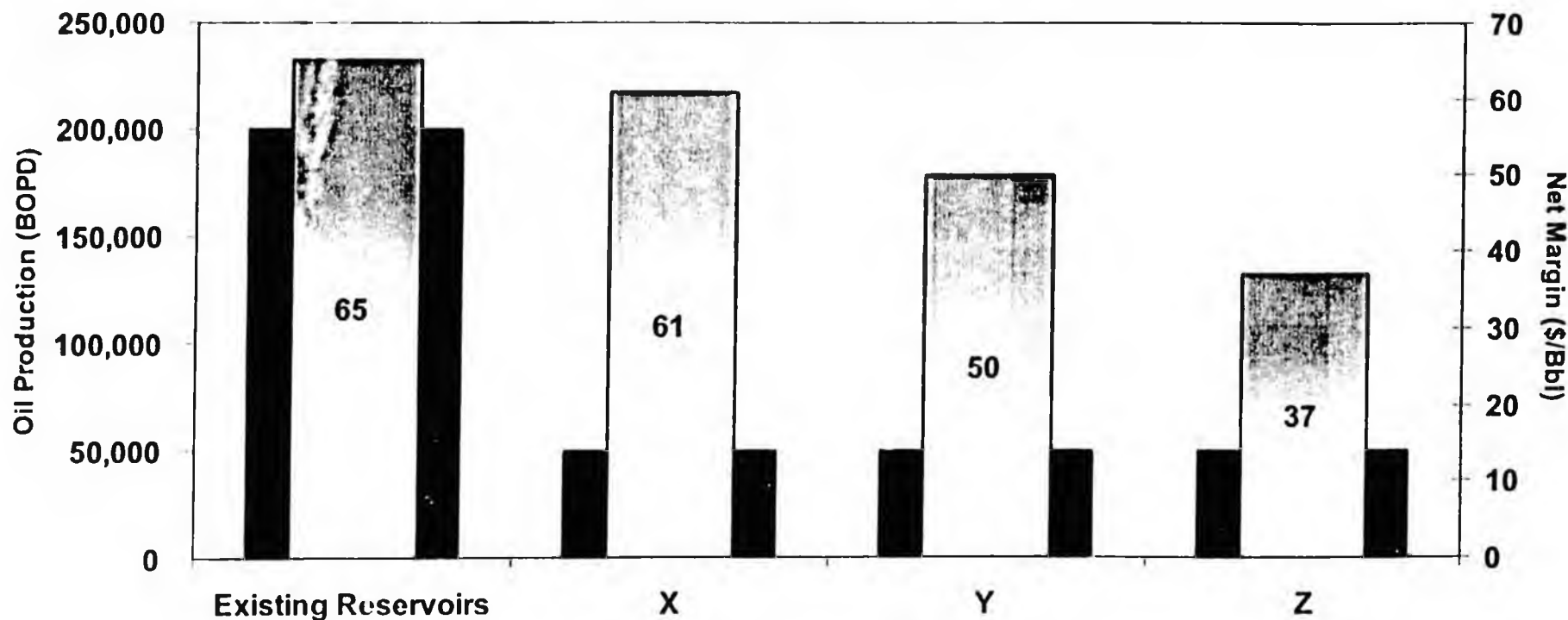
This reduces the rate payable to 25.5%

How ?

\$800 million amounts to \$6.26 Per Barrel Based On This Portfolio



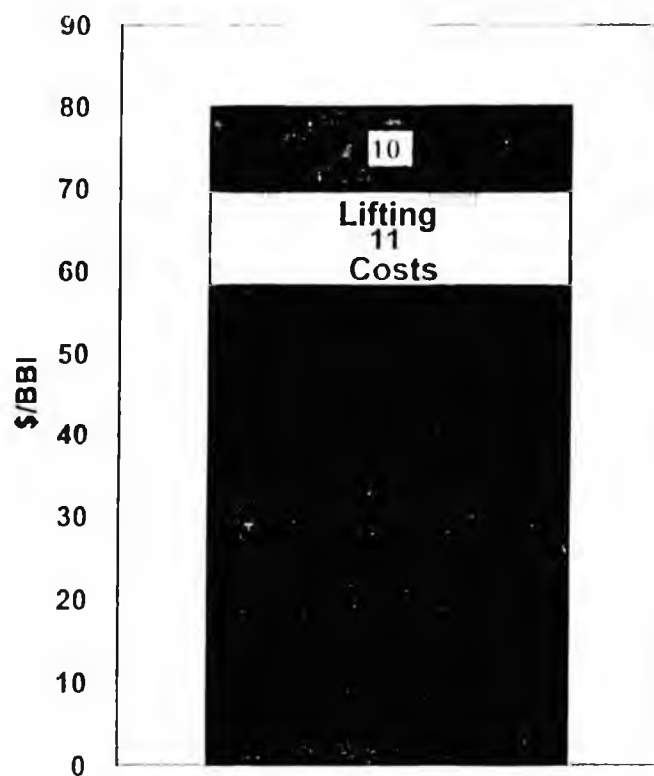
Portfolio Production Rate and Net Margin



The \$6.26 Per Barrel Capital Increases “Costs” And Lowers The Tax Rate

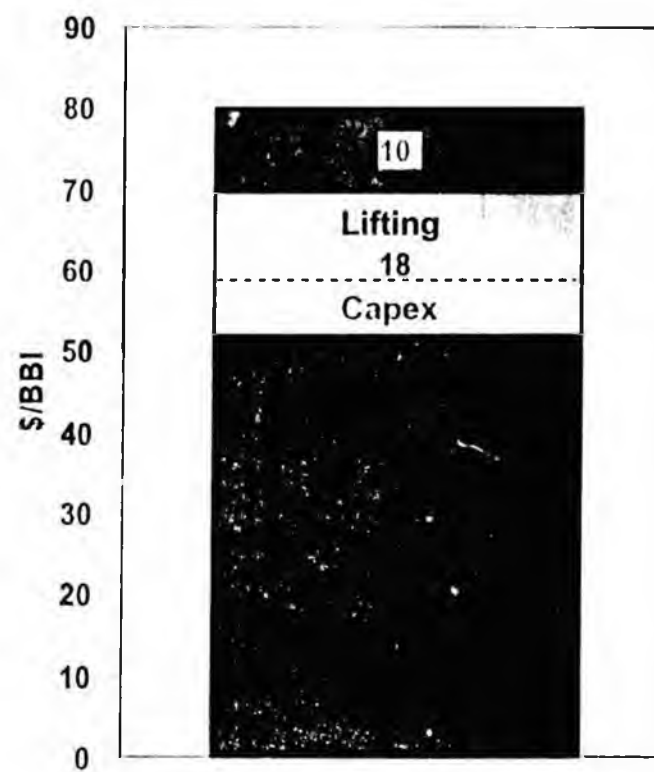


Pre-Capex Margin



Tax Rate
26.9%

Portfolio Profitability

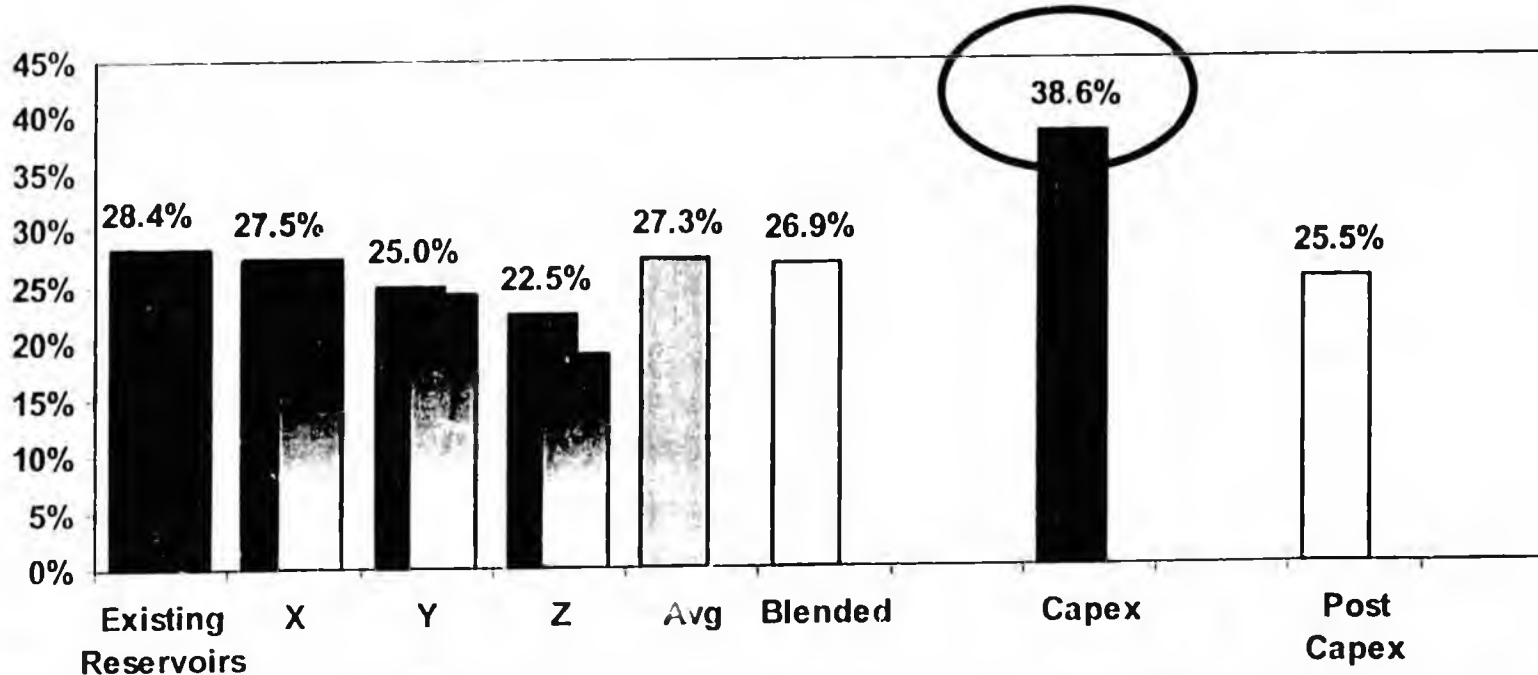


Tax Rate
25.5%

There Is Another Way To Look At This, Though



Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



It is the same as still paying the blended rate of 26.9% on the portfolio production (or having an effective rate of 28.4% on Existing Reservoirs .. down to 18.9% on Field Z) and Alaska paying* 38.6% of that \$800 million capital

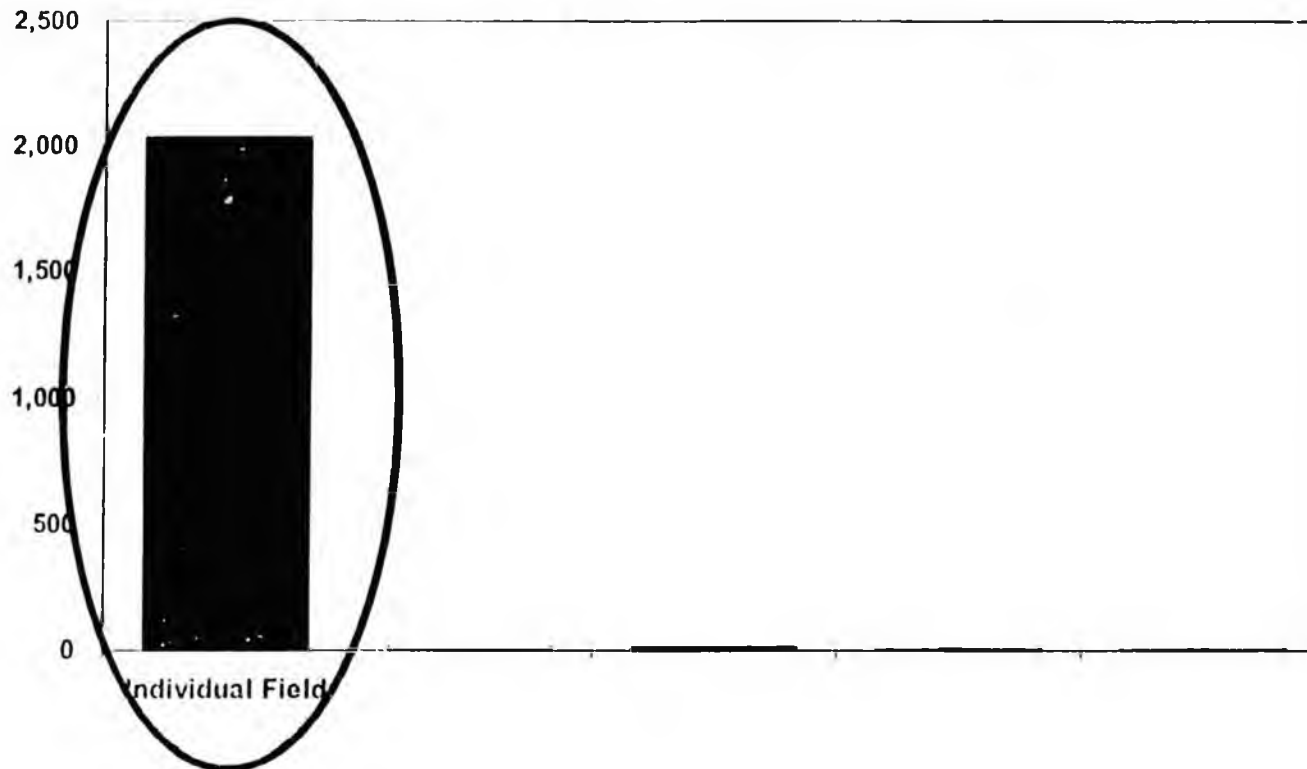
This 38.6% is higher than the Blended tax rate ... and is a function of the capex per barrel and the overall portfolio cost and margin structure

* from PPT only – does not include State and Federal tax effects

Look At The Tax System Through The Amount Of Tax Payable ...



Tax Allocable By Field Within Portfolio



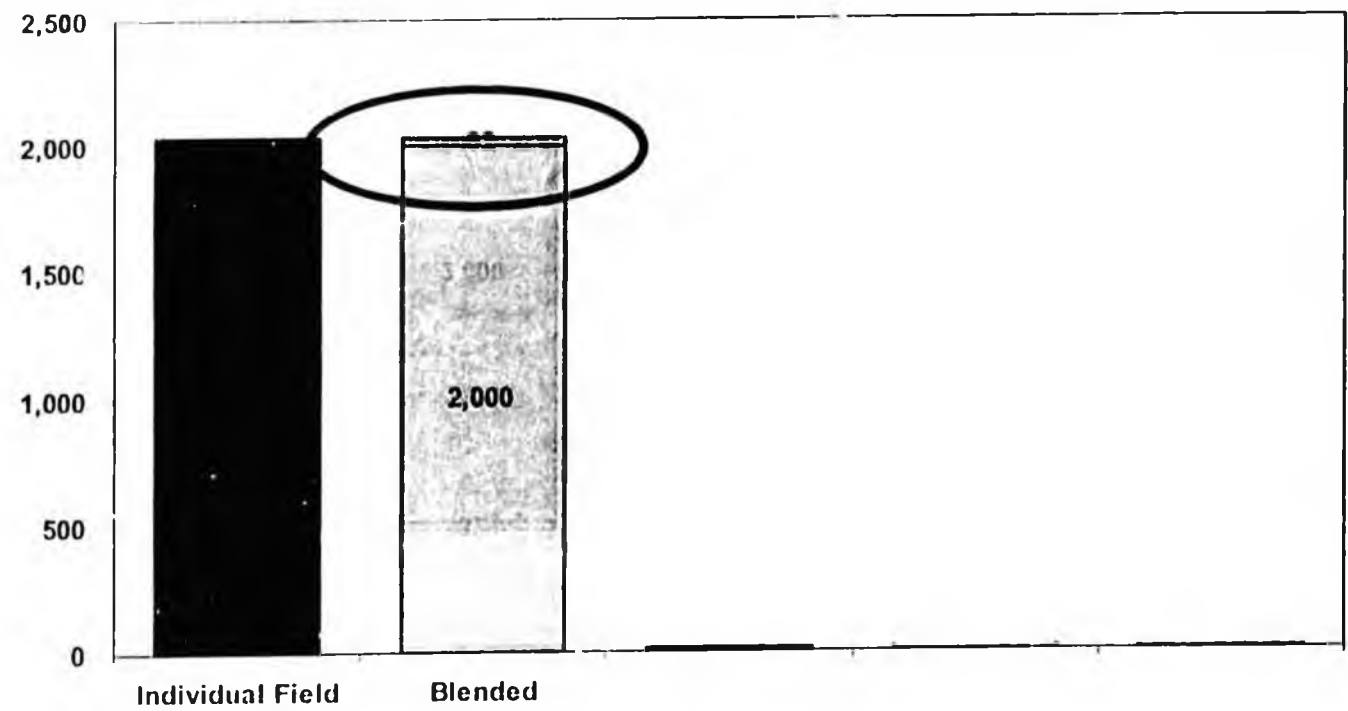
As individual fields, this portfolio would pay just over \$2,032 million in PPT

* from PPT only – does not include State and Federal tax effects



Portfolio Effects Lower Total Tax

Tax Allocable By Field Within Portfolio

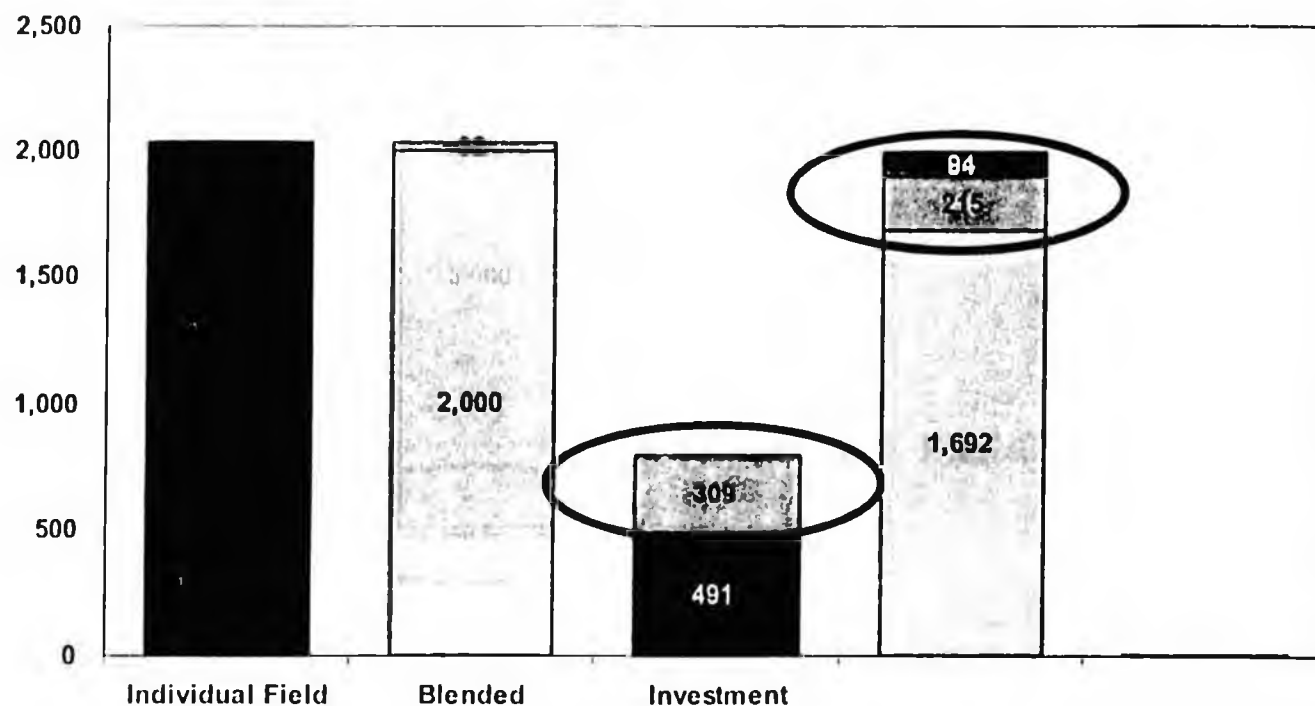


Putting all fields in one portfolio (company) lowers this to \$2Bn ...
... a saving of \$ 32 million



The Big Winner Though Is Capex

Tax Allocable By Field Within Portfolio

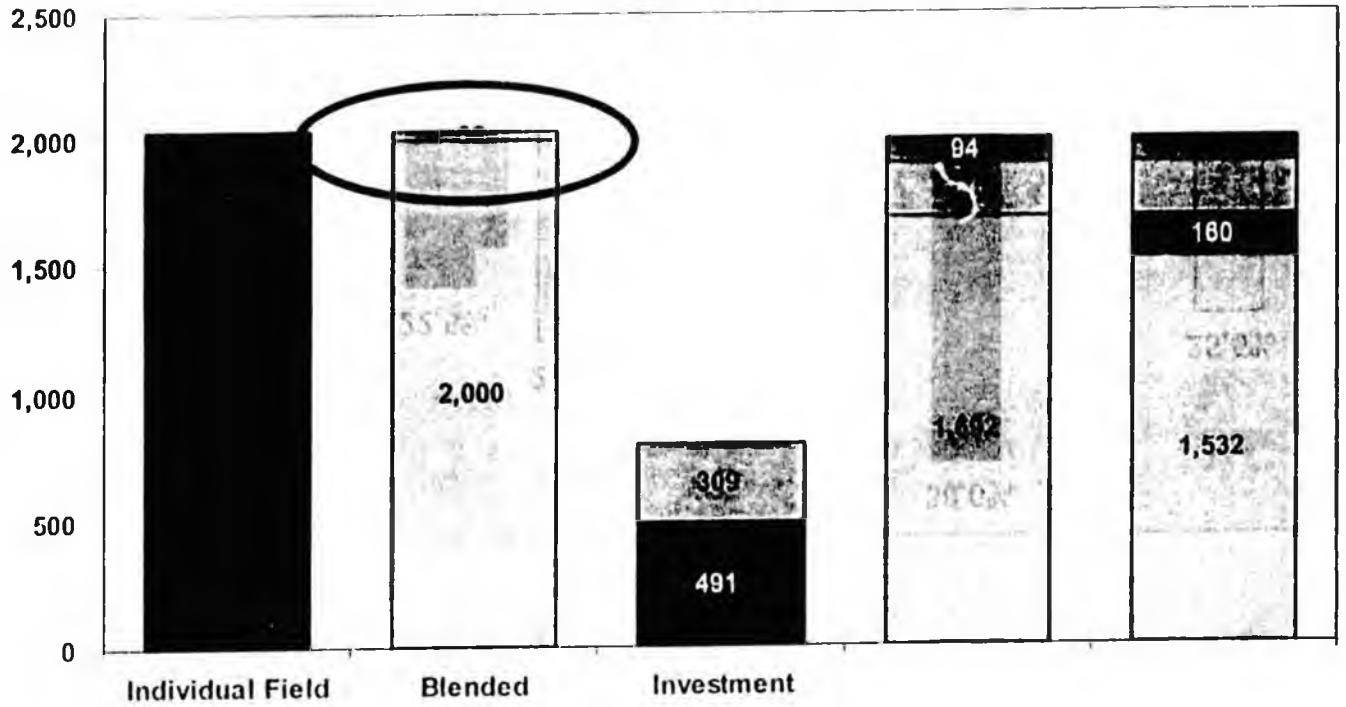


In this example the State pays \$309 million (38.6%) of the capital (the percentage will vary based on overall portfolio net margin per barrel)
The \$309 million can be allocated as \$215 million from reducing taxable income at 26.9% and \$94 million from lowering the rate from 26.9% to 25.5%



But Wait ! That Is Not All

Tax Allocable By Field Within Portfolio

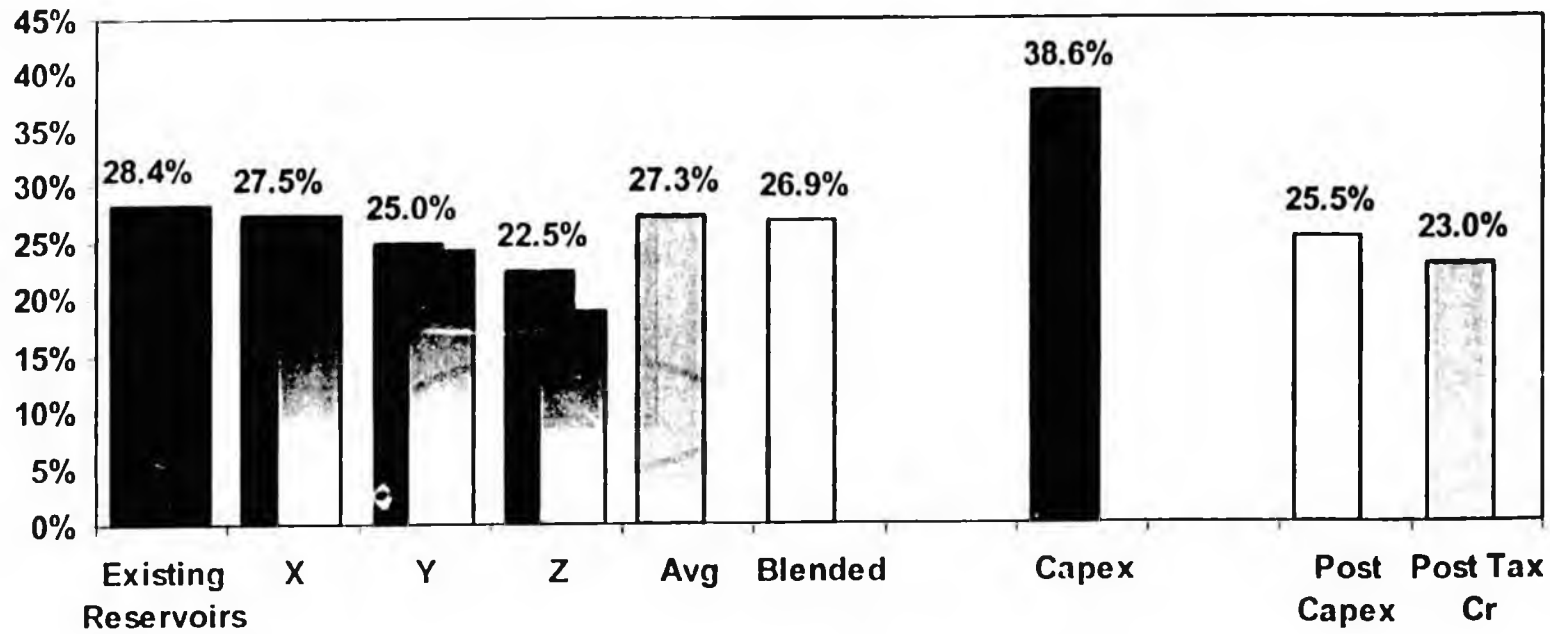


Investment Credits Take a further \$160 million (20% of \$800 million) from the tax payable



After Investment Credits ...

Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



... the effective tax rate is lowered further to 23%*

* In this example

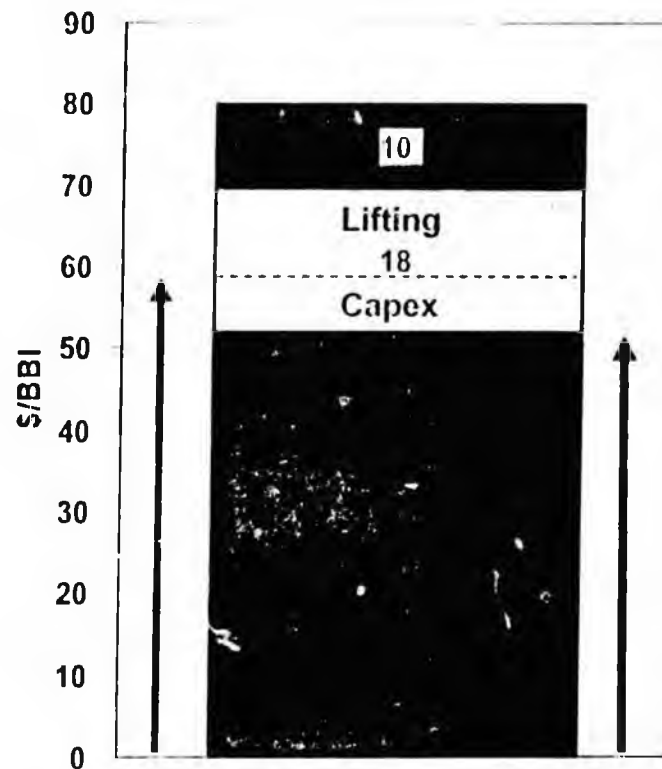
PPT Is Really A Tax On Net Cash Flow Per Barrel



... or, a tax on net revenues that are not reinvested ...

**Operating Margin
Per Barrel**

\$58



**Net Cash Flow
Per Barrel
(after
reinvestment)**

\$52

**Tax Rate
25.5%**

House Oil & Gas Committee

Gross Progressivity Amendment



Progressivity

- **PPT**

- Tax rate increases 0.25% for every dollar that net cash flow per barrel exceeds \$40 (Margin)

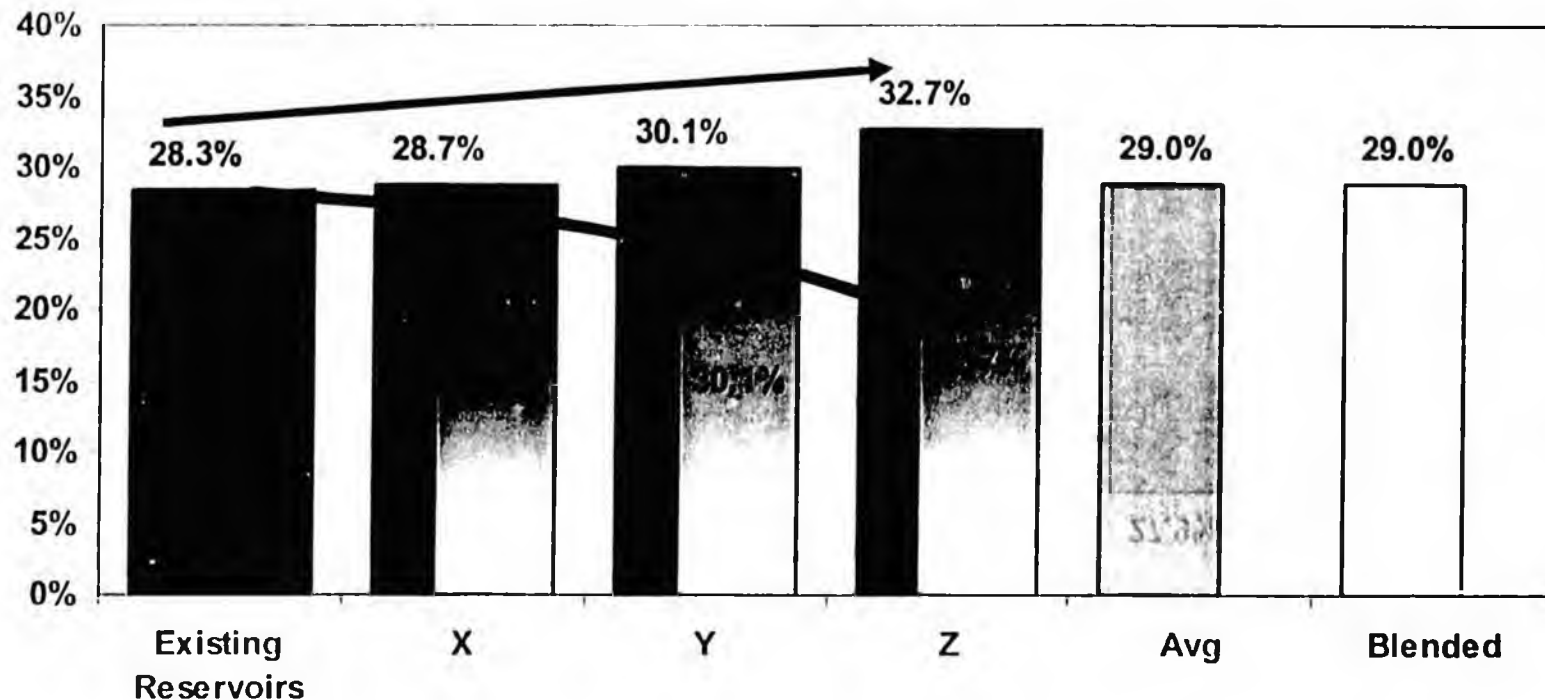
- **House O&G Amendment**

- Maintains the PPT basic rate of 22.5%
- Adds a tax of 0.225% for every dollar that the gross value at the point of production exceeds \$50 (Price)
- Applied to the gross value at the point of production



House Oil & Gas Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

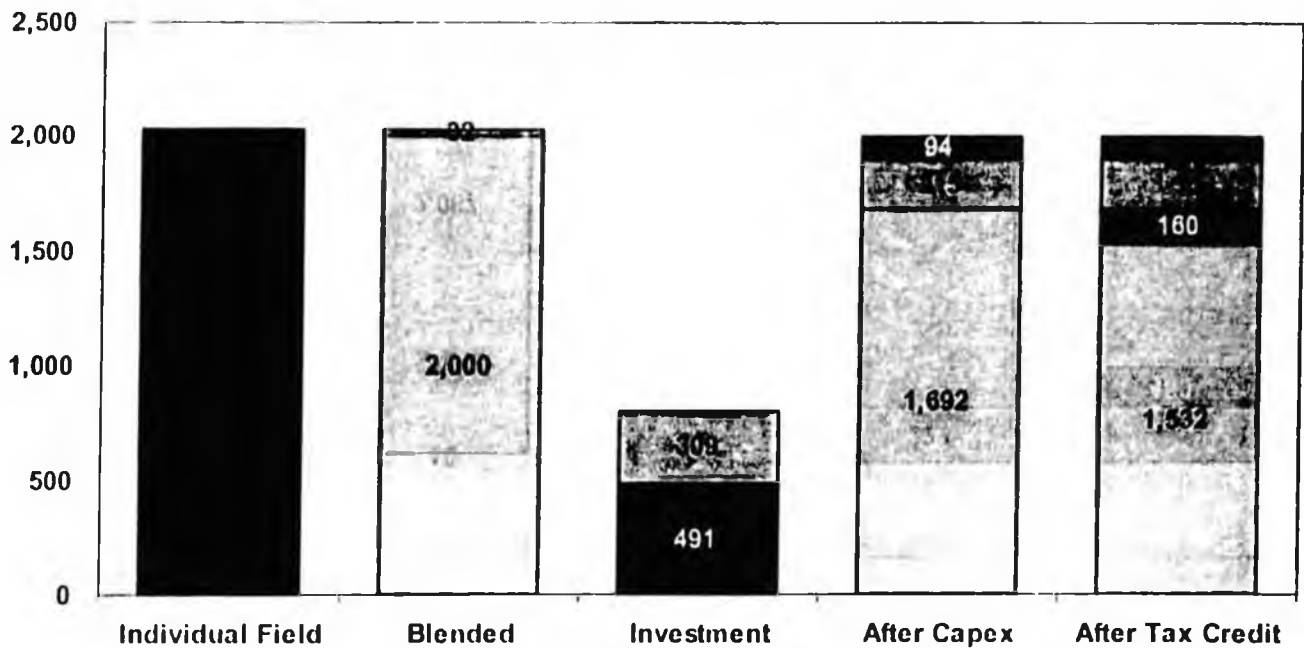


If all of the lower margin results from higher field operating costs then clear regressivity can be seen as more tax is collected and lower margin fields are actually taxed at a higher effective rate than higher margin fields



PPT Progressivity

Tax Allocable By Field Within Portfolio

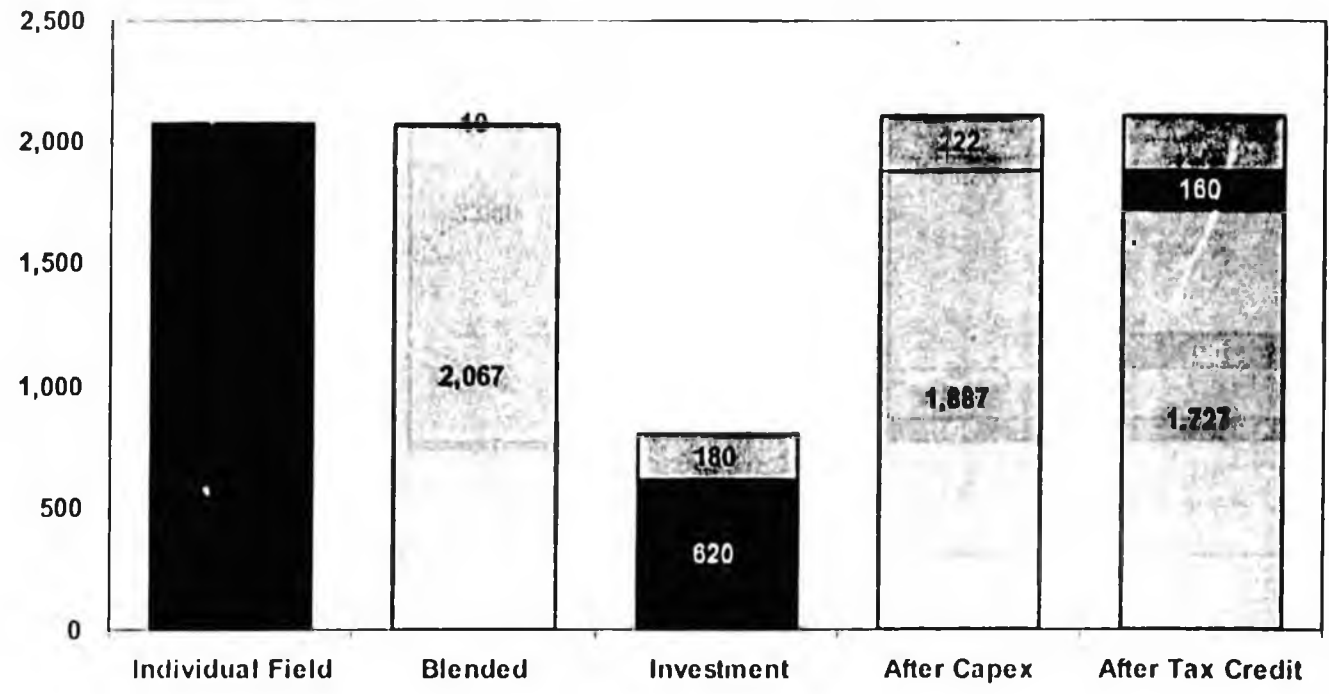


Under PPT progressivity this portfolio would pay **\$1,532 million**
at \$80 ANS West Coast
\$2 Bn before the capital investment



House Oil & Gas Progressivity

Tax Allocable By Field Within Portfolio



**Under House O&G progressivity this portfolio would pay \$1,727 million
-only \$67 million before the capital investment
The net cost of the investment rises from \$331 million to \$460 million***

* Before State and Federal tax impacts



Conclusions

- **A net tax on the margin is a tax on the retained cash flow and not just a tax on simple profitability**
- **Corporate ring fence for production tax allows the effective rate to vary between more, and less, profitable fields**
- **More aggressive net progressivity provides a greater differentiation on the effective rate than simple gross progressivity**
 - Less/lower taxes at low margins
 - More/higher taxes at high margins



Conclusions - Progressivity

- **Progressivity, based on “net”, as manifested in the PPT/ACES structure is more responsive to individual field profitability than that in a “gross” structure**
- **Greater progressivity (raising the maximum rate and / or slope) can achieve even greater differentiation**
 - More tax on legacy investments benefits from current higher prices – that will drop back if prices drop back
 - Lower tax rates on higher cost / lower margin new investments