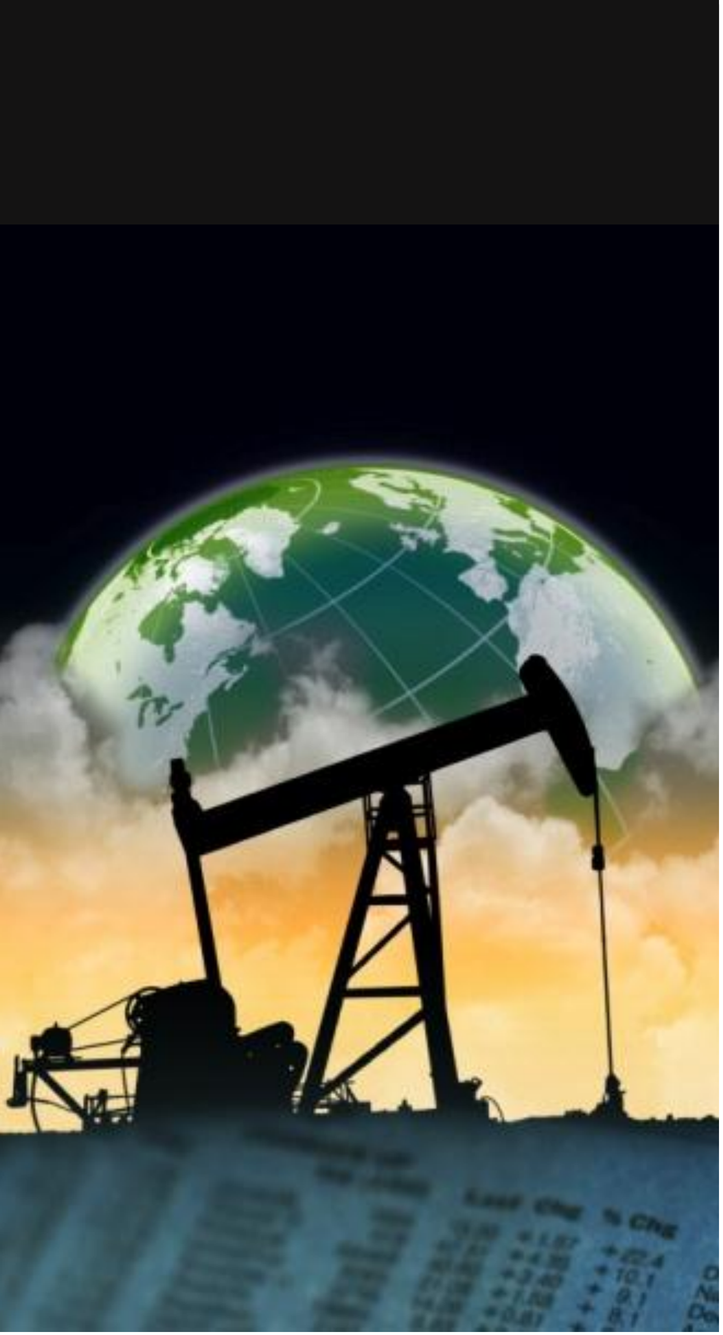


House Resources Committee

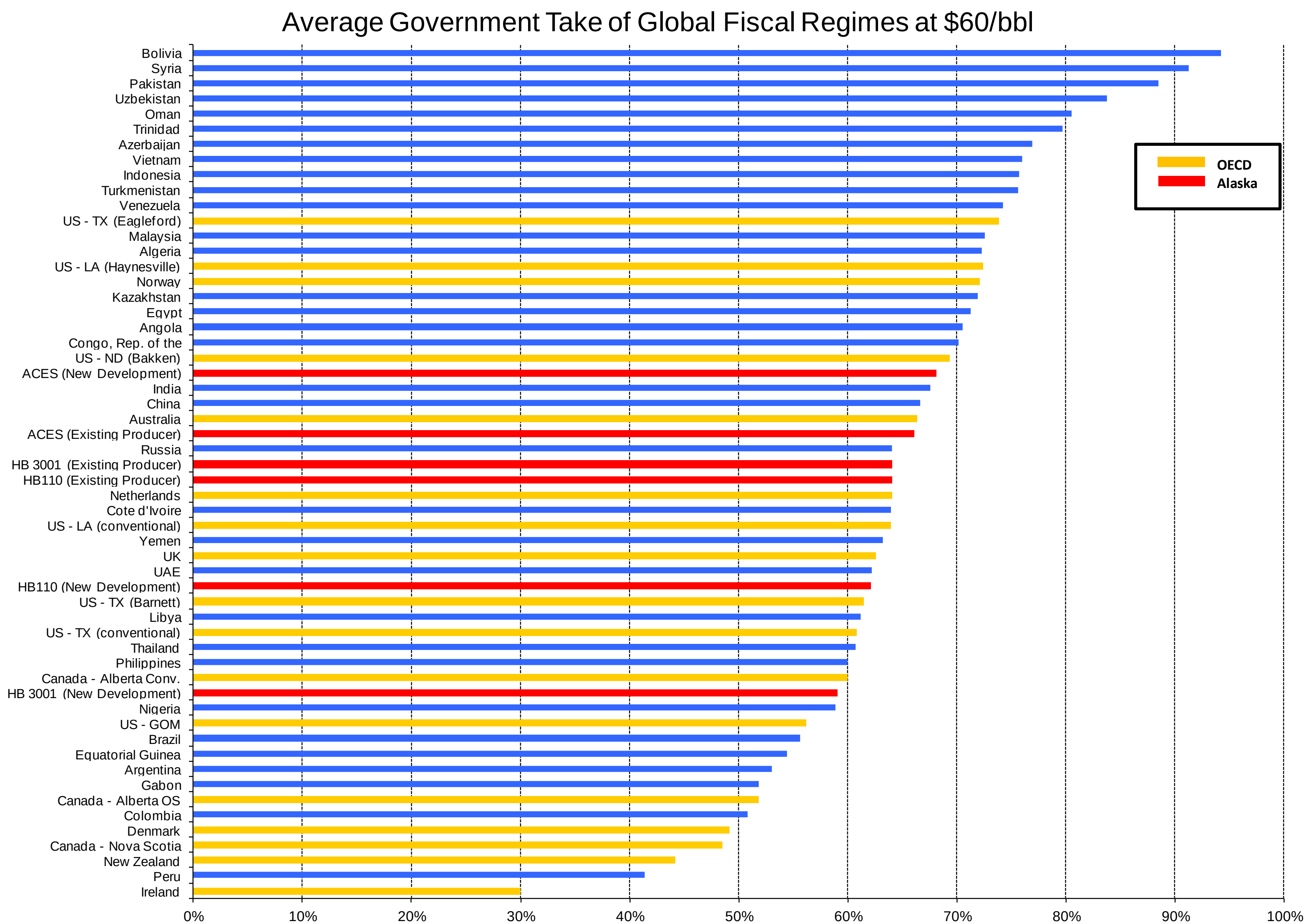
Post-session responses to additional committee questions

June 2012

Janak Mayer
Manager, Upstream
PFC Energy

Alaska's Fiscal Regime in a Global Competitive Context

Regime Competitiveness: Average Government Take at $60/bbl



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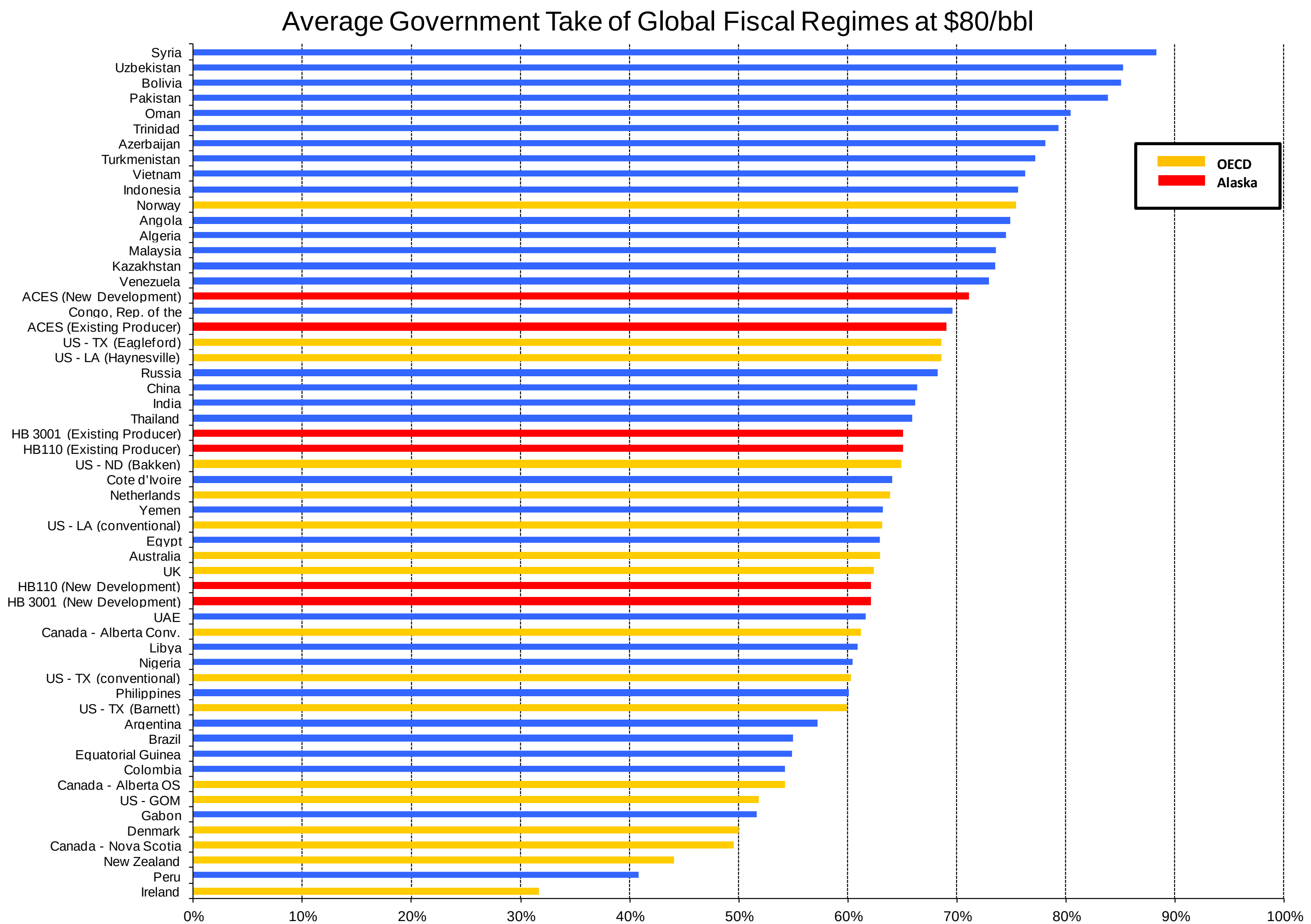
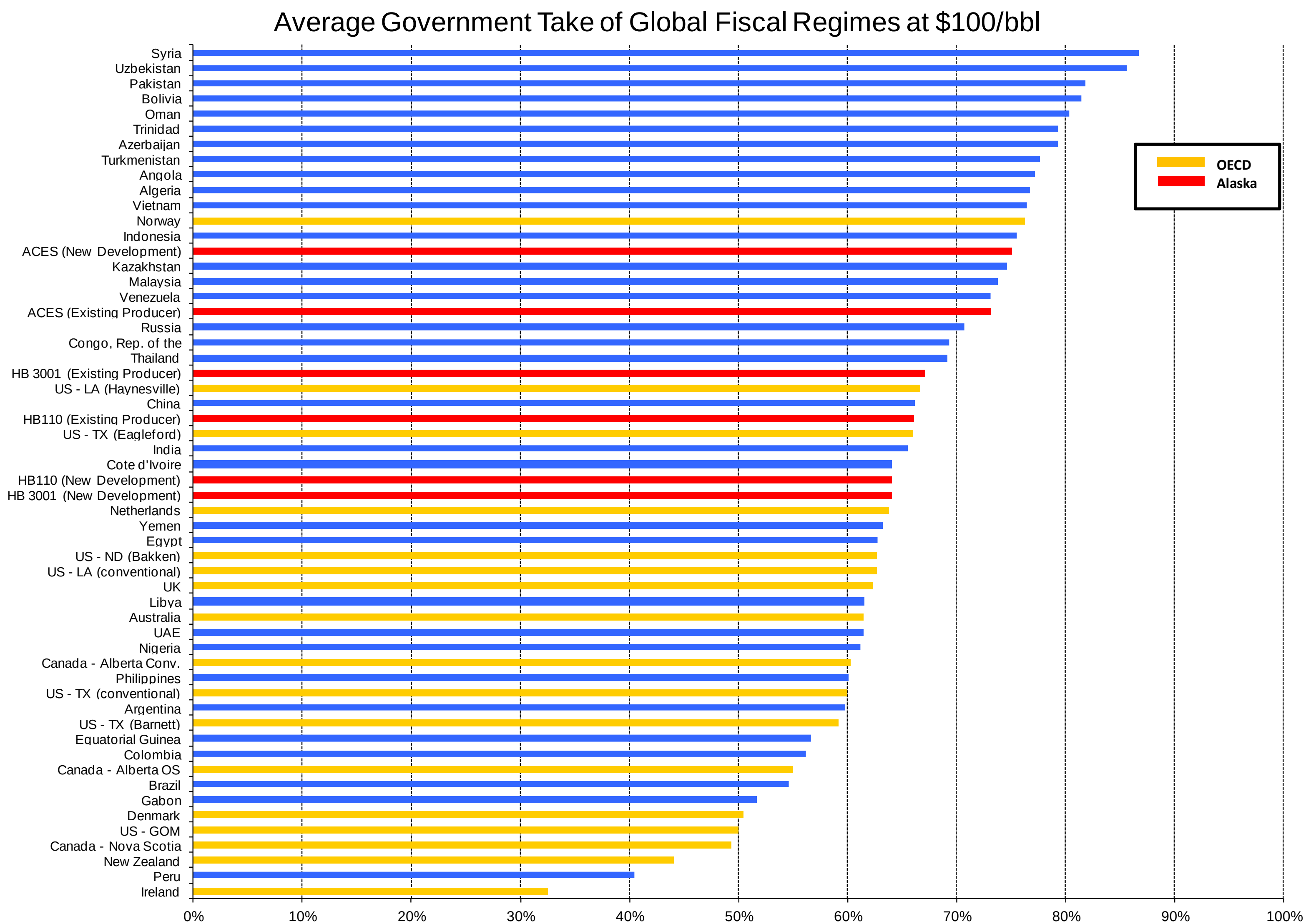
Regime Competitiveness: Average Government Take at $80/bbl



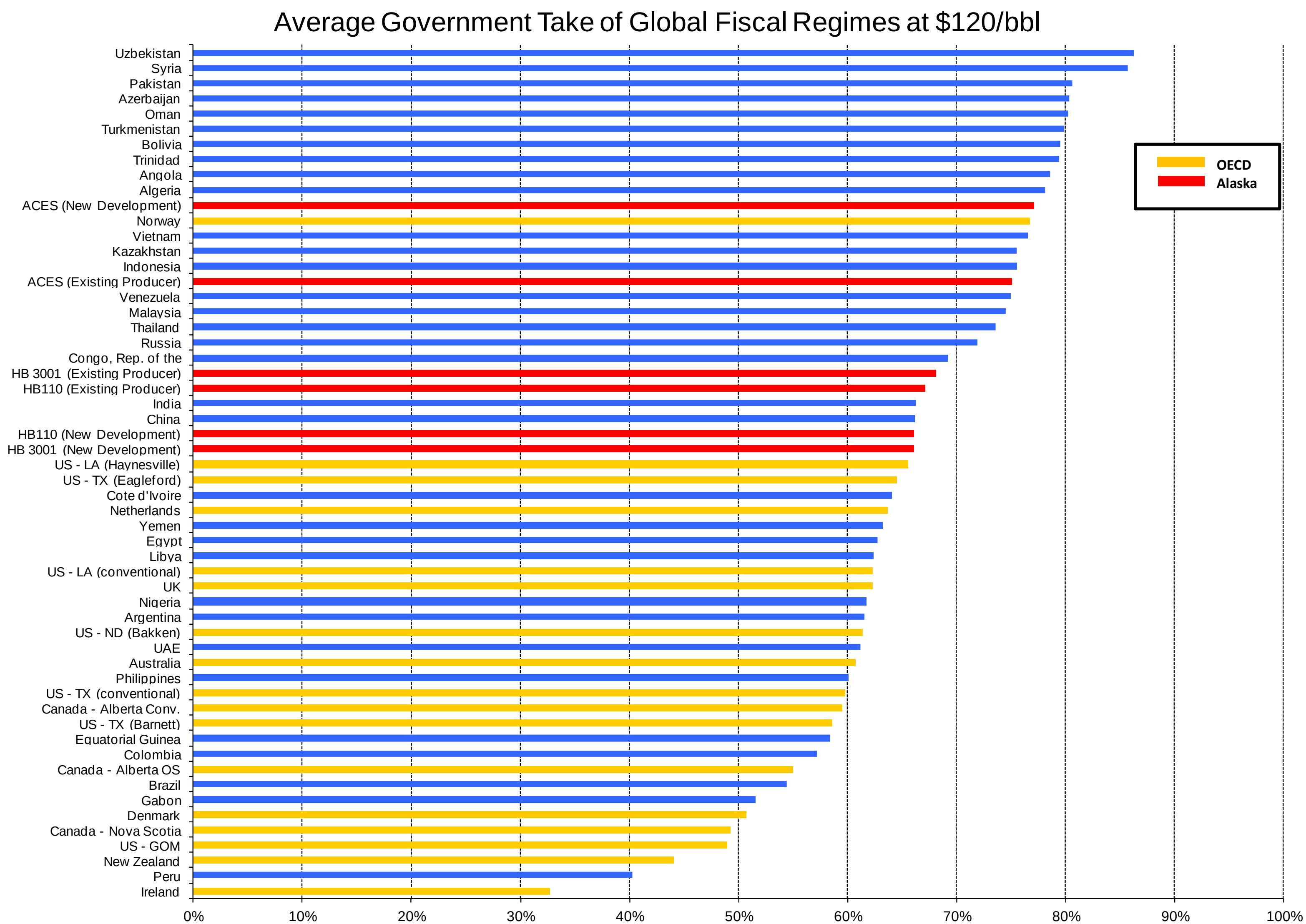
PFC Energy

Regime Competitiveness: Average Government Take at $100/bbl



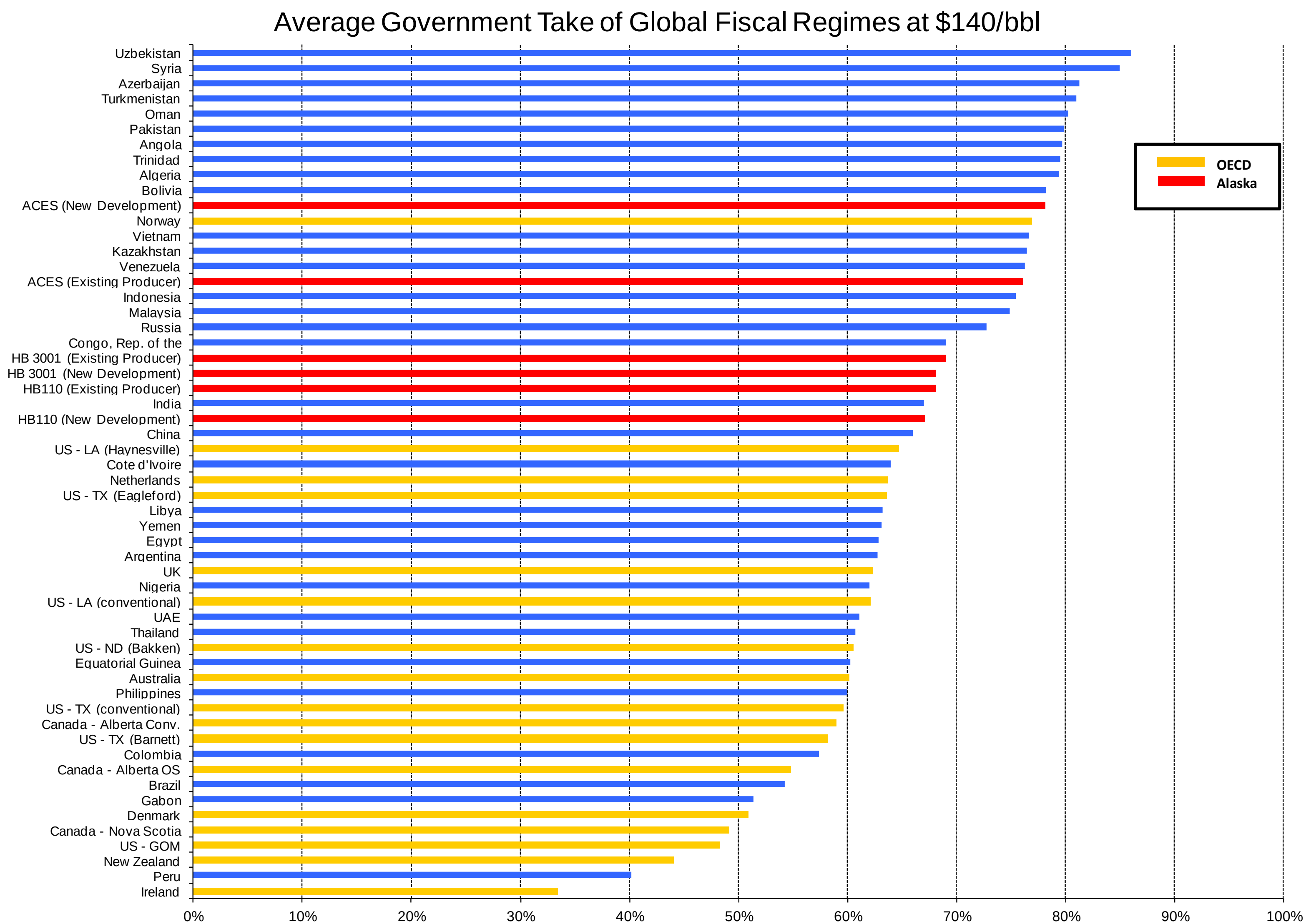
PFC Energy

Regime Competitiveness: Average Government Take at $120/bbl



PFC Energy

Regime Competitiveness: Average Government Take at $140/bbl



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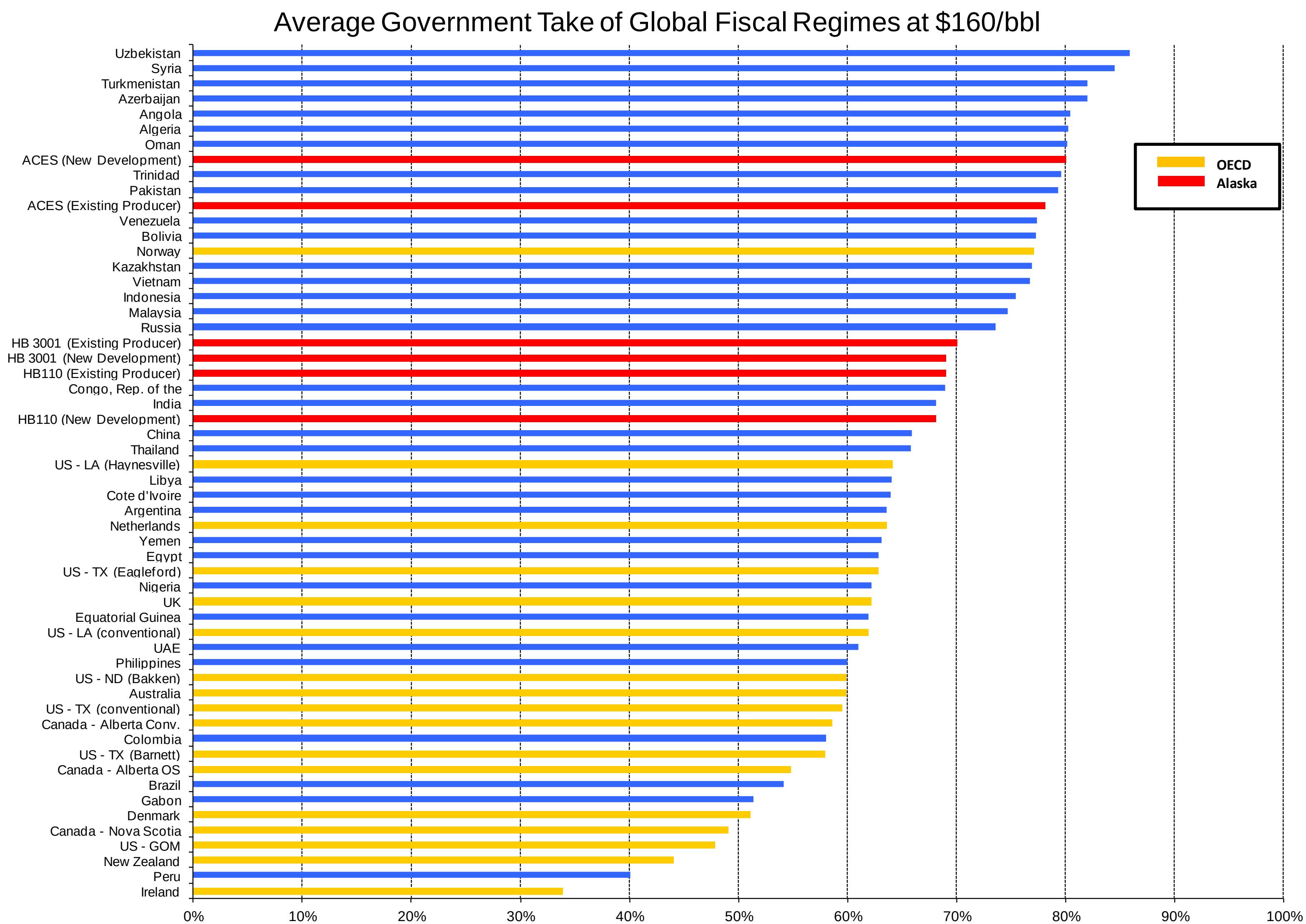
Regime Competitiveness: Average Government Take at $160/bbl



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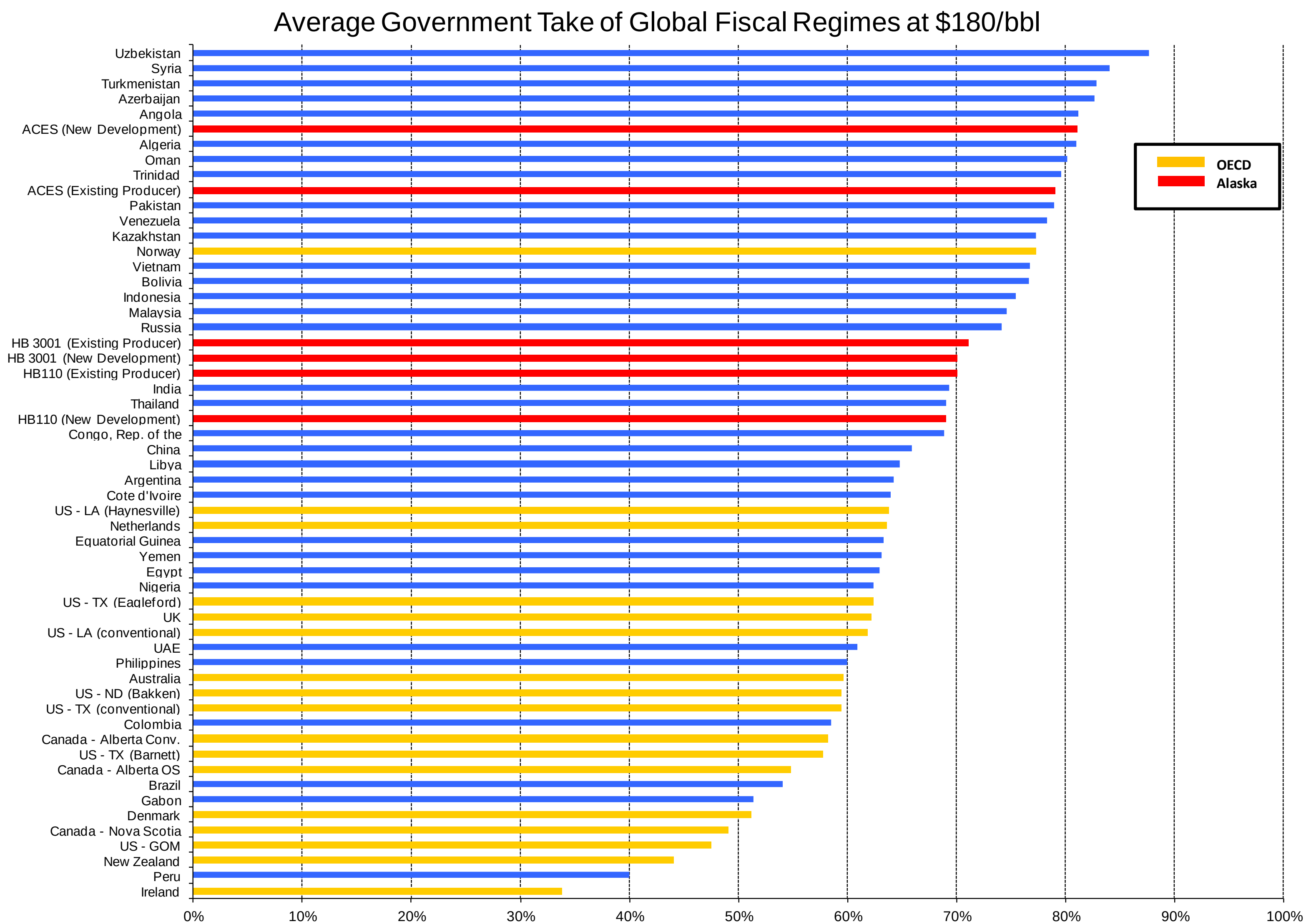
Regime Competitiveness: Average Government Take at $180/bbl



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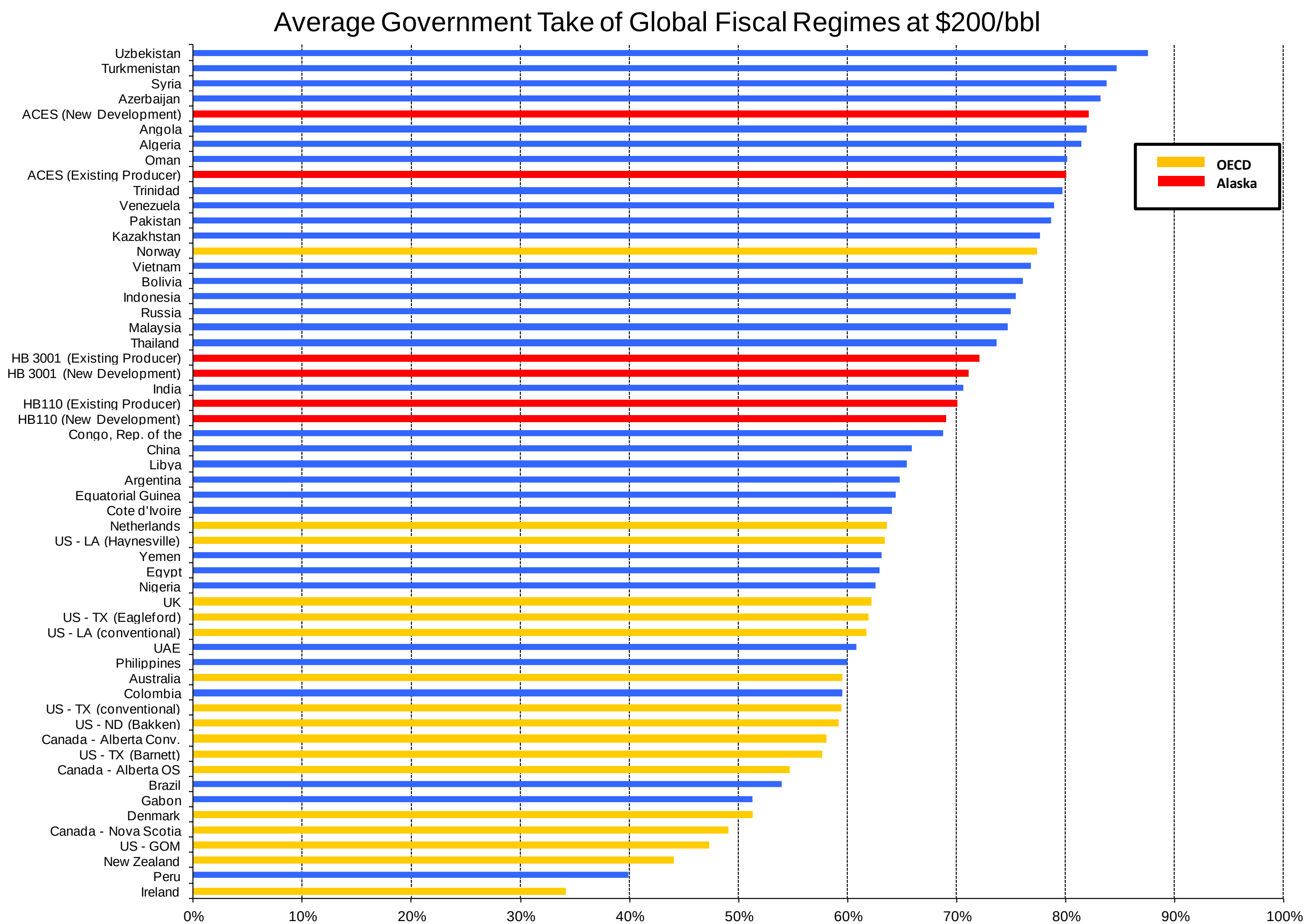
Regime Competitiveness: Average Government Take at $200/bbl



Notes on Government Take Benchmarking

- Benchmarking comparisons of Government Take are highly sensitive to a range of assumptions, in particular those around the magnitude and timing of project costs and revenues
  - In order to best reflect the real impact of different fiscal systems, PFC's benchmarking approach where possible uses production and cost assumptions for actual, representative projects in each regime, rather than comparing a single "reference field" across all regimes
- These benchmarking slides have been extended and updated since initial presentation to House Resources Committee on April 23
  - As requested, a wider range of prices have been shown, and HB 110 and HB 3001 have been included in the comparison
  - Some changes have been made in the production profile and cost assumptions for both the "Existing Producer" and "New Development" Alaska cases
    - These changes have been made to maintain consistency with updates to the overall modeling approach made during the course of work undertaken with Senate Finance Committee in April 2011, but not included in the benchmarking slides previously presented
    - The main change is to reduce the timeframe included in the analysis from 40 to 20 years. This reduces the impact of inflation (through "bracket creep") on Government Take over time, resulting in a slight reduction in Government Take (1-2 percentage points) shown under ACES in both cases
    - This is no impact on the overall findings of the comparison – that at current price levels, Alaska has one of the highest levels of Government Take in the OECD, and with a degree of price progressivity that makes it among the highest in the world at particularly high price levels.

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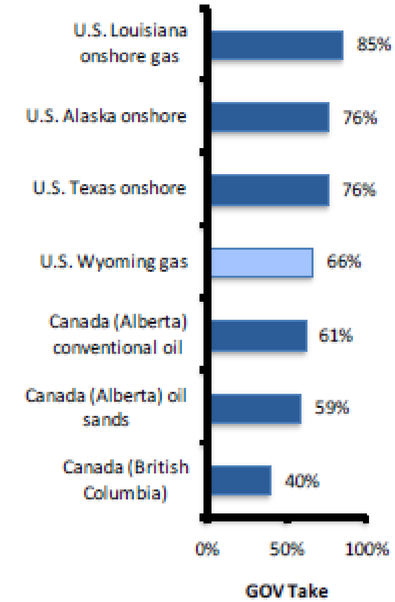
Comparison to Other Benchmarking Reports

- House Resources Committee requested analysis of how these benchmarking results compare to other benchmarking reports and approaches :
  - Requested Comparison to DOR Report "*Alaska's Oil & Gas Fiscal Regime*"
    - This report does not seek to benchmark different regimes against each other, but rather to present the details of each system to enable comparison between the different terms. The report provides an effective way to compare the key fiscal elements across a range of relevant peer regimes.
    - The summary of the fiscal terms across the different jurisdictions presented in the DOR report are generally consistent with those used by PFC Energy in this benchmarking analysis.
    - For regimes where royalty payments may be made to private rather than public landholders, such royalties have been included, for comparability, in the "Government Take" figures shown in PFC's benchmarking analysis. Private royalty rates assumed by PFC are generally at the higher end of the range documented in the DOR report.

Comparison to Other Benchmarking Reports (cont'd)

– Requested Comparison to analysis of North American Onshore Fiscal Systems in IHS CERA's Report "*Comparative Assessment of the Federal Oil & Gas Fiscal System*", p95

- The comparative findings of this analysis seem broadly speaking consistent with PFC Energy's benchmarking conclusions. Alaska is presented on the referenced chart as the second highest of the benchmarked onshore US regimes, below only Louisiana onshore gas, and at the same level as Texas onshore
- The "base case" presented in this report is one run at $75/bbl oil and $6/mcf gas. By comparison, in PFC's analysis, at $60/bbl oil, Alaska Government Take under ACES is below that for Louisiana and Texas unconventionals, and marginally above Louisiana and Texas conventionals (the key difference between conventionals and unconventionals being cost levels). At $80/bbl, in PFC's analysis, Alaska is slightly above, but close in range to Louisiana and Texas conventionals.
- The differences between the regimes at higher prices are a function of Alaska's highly price-progressive fiscal system, in comparison with the highly regressive fiscal systems in Lower 48 jurisdictions. As the report focuses on the $75/bbl case, it does not capture the divergence between Alaska's system and the Lower 48 systems that occurs at higher prices.
- The inclusion of dry gas projects in the IHS CERA report's analysis is another source of difference in methodology in comparison to PFC's benchmarking. In a regressive, fixed-percentage royalty system like Louisiana's, the lower revenues earned by dry gas projects, combined with a fixed % royalty, result in particularly high levels of government take, explaining the Louisiana gas findings in this study
- While the relative findings at the $75 price level are comparable to PFC's, the overall levels of government take calculated within the IHS CERA report are higher than in the PFC Energy analysis. Without more information about the assumptions underlying the analysis, it is not possible to comment further on possible causes for the divergence in specific results.



Source IHS CERA

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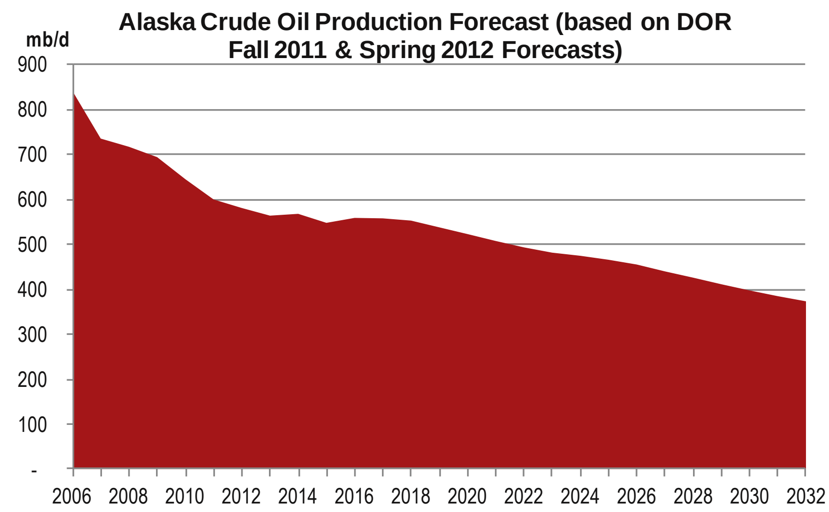
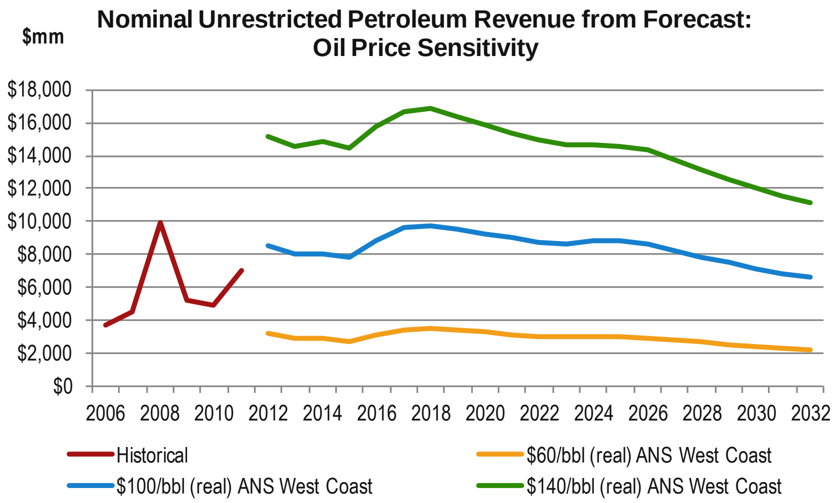
Alaska's Future Petroleum Revenues: Sensitivities to Oil Price, Production Decline, and Fiscal Terms

Oil Price is the Major Determinant of Alaska's Future Petroleum Revenue





- The major factor determining Alaska's future petroleum revenue is not oil & gas fiscal terms, or even, in the short run, production levels, but rather something entirely outside Alaska's control: the crude oil price
- Restricting a sensitivity analysis only to the a range of oil prices observed in the last 5 years, and **holding future production constant** (based on DOR forecasts) the potential variation in possible future petroleum revenue is substantial:
  - In a $140/bbl environment, revenue in 2032 under ACES would approach $12bn
  - In a $60/bbl environment, revenue in 2032 under ACES would be as low as $2bn
- In reality, the potential for variation is even greater than this, since production also responds to price:
  - In a sustained high price environment, more projects would be economic, and long-run production would improve
  - In a sustained low price environment, fewer projects would be economic and sustaining capital would be lower, resulting in a more rapid decline in long run production

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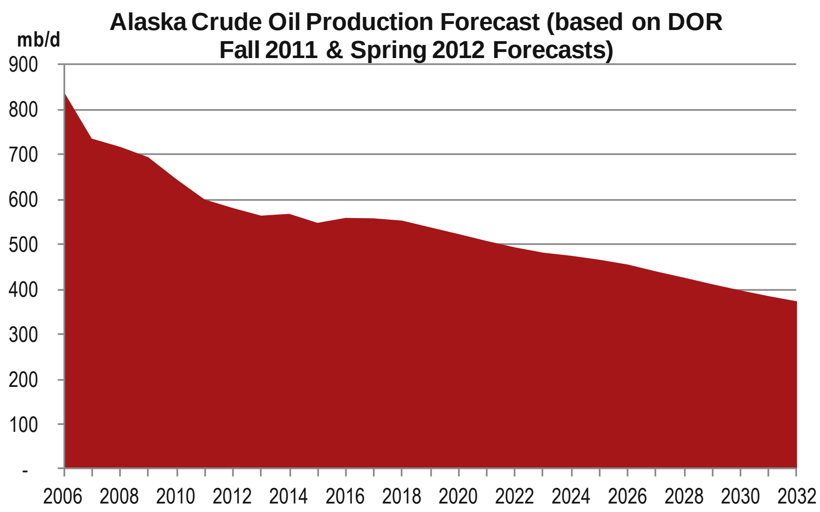
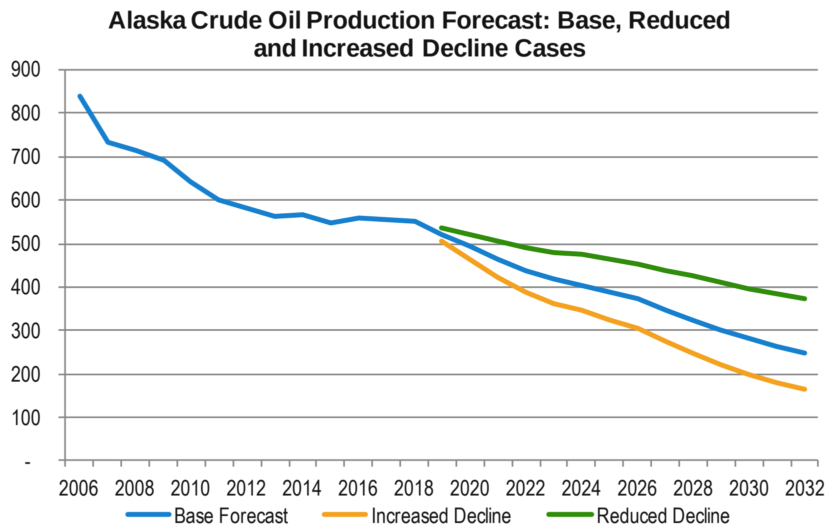
Three Decline Cases





- To examine the impact of changes in investment incentives on production, and therefore on state revenue, we can examine sensitivities around the state's long-run production forecast decline rates
  - The 2019-forward timeframe has been chosen for this analysis, as the decline in the Base Forecast (from DOR Fall 2011 and Spring 2012 production forecasts) is relatively steady over that period. This time frame also reflects one that may be conservatively viewed as impacted by policy changes made in the near future.
  - The Base Forecast anticipates an average annual production decline between 2019 and 2032 of ~5.5% (including the contribution from new producing areas brought on-stream), yielding production of ~250 mb/d in 2032
  - Increasing the average decline rate by 50% (to ~8.3% per annum) would see production declining to ~160 mb/d in 2032
  - Reducing the average decline rate by half (to ~2.8% per annum) would see production fall to ~375 mb/d in 2032

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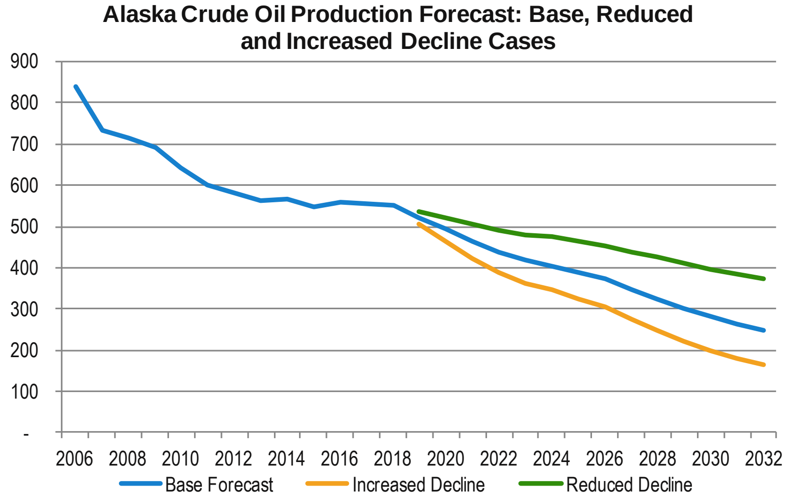
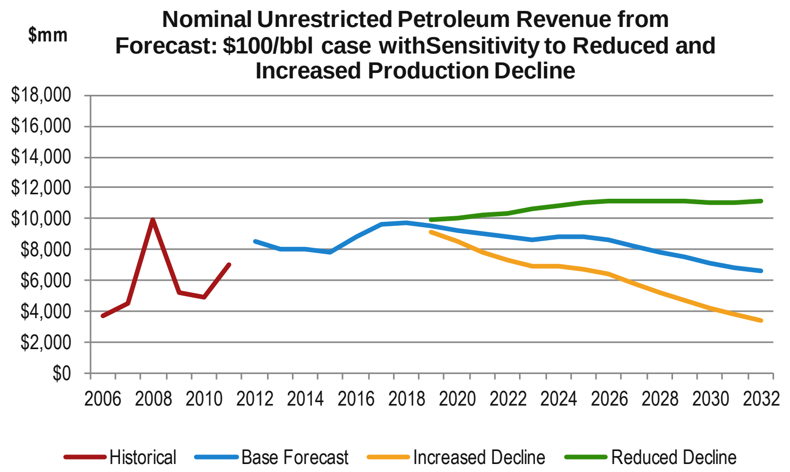
Impact of Decline Assumptions on Future Revenue





- The range of impact of these different decline scenarios on future revenues is almost as large as the impact of the crude oil price scenarios discussed earlier
  - In the low decline scenario, more robust production combined with the impact of inflation mean that nominal revenues would continue to grow beyond 2019, reaching ~$12 bn at a nominal crude price of $100/bbl
  - In the high decline scenario, 2032 nominal revenues would fall well below the $6 bn level anticipated in the Base Forecast case, reaching less than ~$4 bn even with nominal crude prices at $100/bbl

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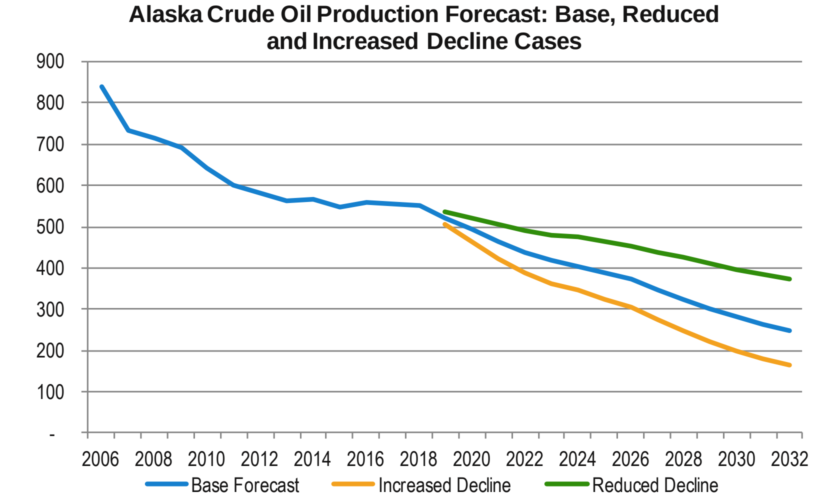
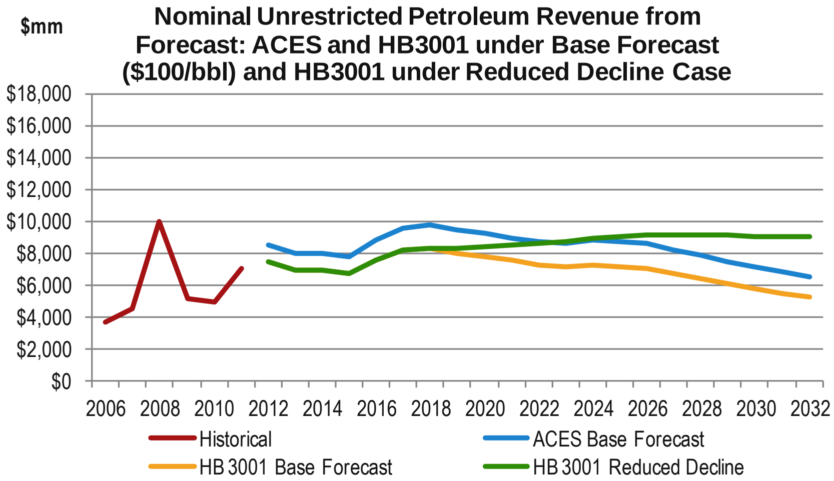
Fiscal Terms Changes and Investment Impacts





- Even significant changes to fiscal terms, by contrast, have a far smaller impact on future revenues than either oil price or future production declines
  - Under the Base Forecast decline case, at $100/bbl crude oil, HB 3001 results in a parallel shift of the revenue curve, reducing the state's petroleum revenue by a little over $1 bn each year
- Because of this, if an improvement in fiscal terms can stimulate sufficient new investment to stem declines, it has the long run potential to increase revenue, despite the near-term cost of the change
  - A reduction in Government Take to the extent proposed under HB 3001 or HB 110 would generate a near-term cost to the State of Alaska of ~$1 bn per annum relative to the ACES Base Forecast. The long run revenue implications of such a fiscal change would depend on the impact on new investment
  - A response in investment sufficient to move production from the Base Forecast to the Reduced Decline case in this example would be revenue neutral by the mid-2020s, and even revenue positive after that point

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Impact of Changes in Fiscal Terms on Upstream Investment: Assessing the Evidence from Alberta, Canada

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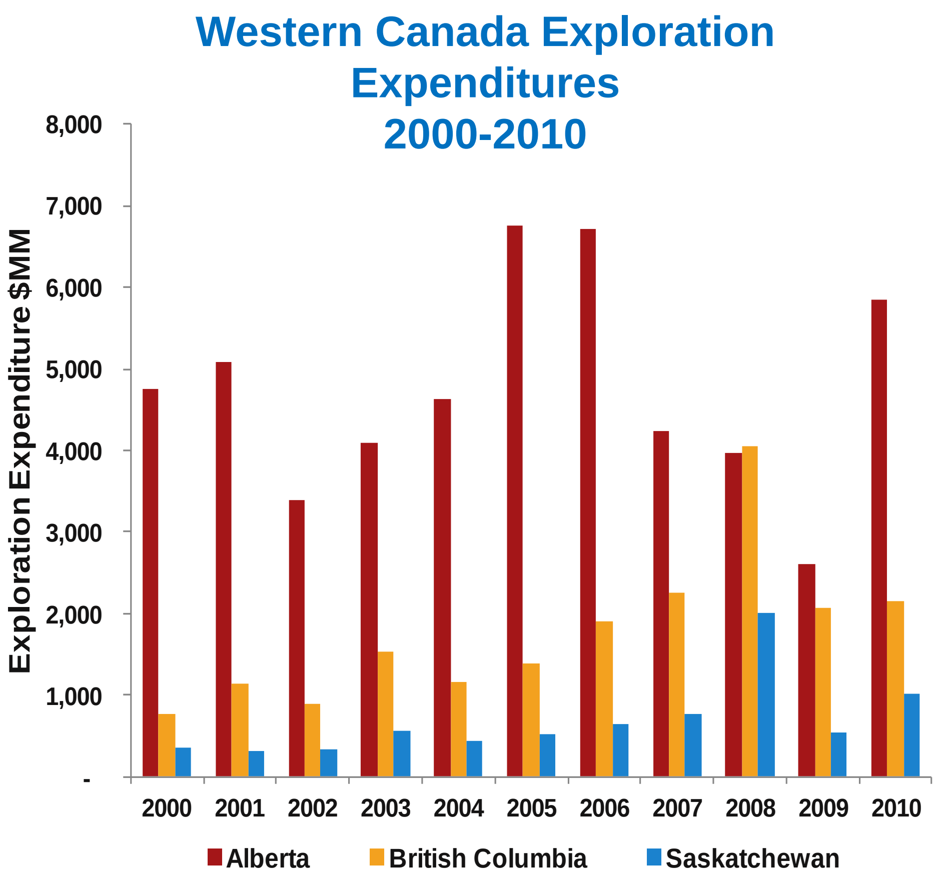
Exploration Spending in Western Canada

- Alberta has historically accounted for the majority of exploration expenditures in western Canada
- The less competitive fiscal terms introduced in Alberta in 2007—which eliminated royalty holidays on new wells—were accompanied by a sharp decrease in exploration activity in that province, and a reallocation of exploration spending to Saskatchewan and British Columbia (BC)
- In 2010, responding both to this competition and to reduced expenditures resulting from the 2008-2009 economic crisis, the Alberta Government approved a new fiscal framework, designed to "position Alberta as one of the most competitive North American destinations for energy investment"
- Since then, exploration expenditures in Alberta have recovered from the crisis far more quickly than in other jurisdictions

- **Question**: Is the relationship between exploration spending and fiscal change causal, or merely correlative?



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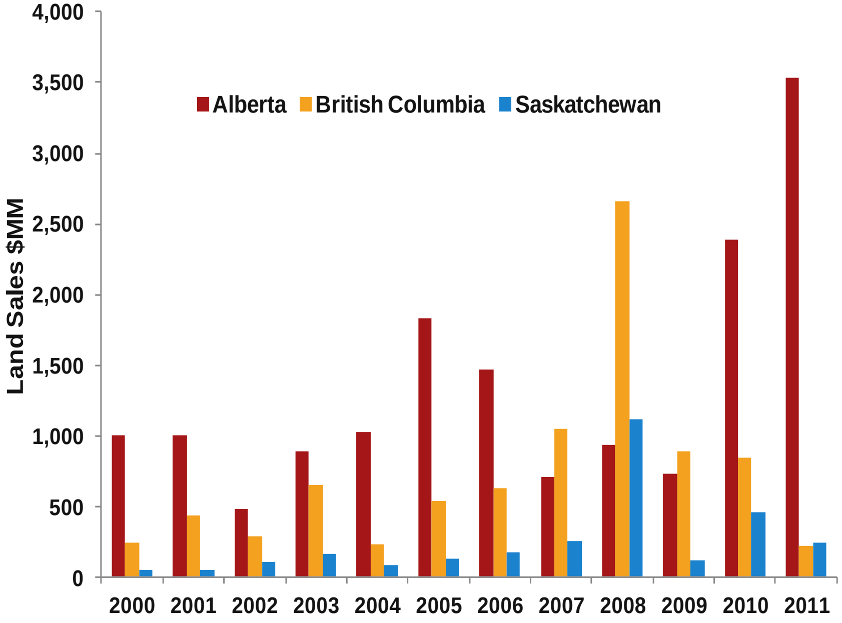
Land Lease Revenue, Western Canada

- A significant share of exploration expenditures is accounted for by spending on land lease sales—securing acreage rights for future drilling. Strength in land lease revenue is normally a signal of future drilling intentions, as acreage can only be held for a defined period without seismic and drilling activity before reverting to the government
- For both Saskatchewan and BC, the rise in land lease sales revenue in 2007 and, in particular, 2008 accounted for a significant share of the rise in overall exploration expenditures
  - Land lease spending over the 2000-2010 period accounted for ~31% of total exploration spending for Alberta, and a higher 36% for Saskatchewan and 44% for BC
  - In 2008, land lease spending accounted for ~66% of total exploration spending for BC and ~56% in Saskatchewan, while that number reached only 24% for Alberta (an improvement over the 17% recorded in 2007)

Western Canada Land Lease Sales Revenue 2000-2011



- While a share of this land lease spending in Saskatchewan and BC can be ascribed to upstream players "voting with their feet" in order to send a signal to the Alberta Government regarding fiscal changes, it is also the case that:
  - In BC, the 2007-2008 period marked the major positioning by the exploration & production sector in the emerging Horn River and Montney shale gas plays;
  - In Saskatchewan, 2008 marked the major positioning in the emerging Exhaw/Bakken play, being the northern extension of the Bakken light tight oil (shale oil) play in North Dakota

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Commodity Prices Drive Upstream Activity

- As shown in the slide following, however, it has been movements in commodity prices—and in particular, the dramatic downward shift in natural gas prices—that has been the largest contributor to changes in upstream activity in Alberta over the past 5 years
  - From April 2006 through December 2007, the Henry Hub gas price (the market price for North American gas sales) averaged $6.74/mmbtu, or ~$6.15/mmbtu at the AECO-C gas storage pricing point on the Alberta border
  - After rising to average as high as $11.70 in the summer of 2008, gas prices collapsed in the face of the economic downturn in the fall of 2008 and the rapid growth in North America shale gas production. Over the period December 2008 to April 2012, the Henry Hub price averaged $3.98/mmbtu (and as low as $1.95/mmbtu in April of this year), or ~$3.38/mmbtu at AECO-C.
- While oil-directed drilling remained relatively stable over the period—increasing over the past 18 months or so in response to firming crude prices—gas directed drilling has fallen considerably from the prior highs
  - Roughly 11,540 gas directed wells were drilled in Alberta over the 04/2006 – 03/2007 period. Over the same period in 2008-2009, gas directed drilling fell to 6,895 wells and, for the 2011-2012 period, totaled only 1,641 wells
  - Oil-directed drilling (excluding the oil sands) has largely moved in the opposite direction. From a low of 1,669 wells drilled over the 04/2007 through 03/2008 period (reflecting budgets based on WTI prices in the low $60/b range) and 1,376 wells over the 2009-2010 (responding to weak oil prices and uncertain economic signals), oil-directed drilling ramped up to 3,157 wells in 2011-2012, a prior-decade high for the sector.

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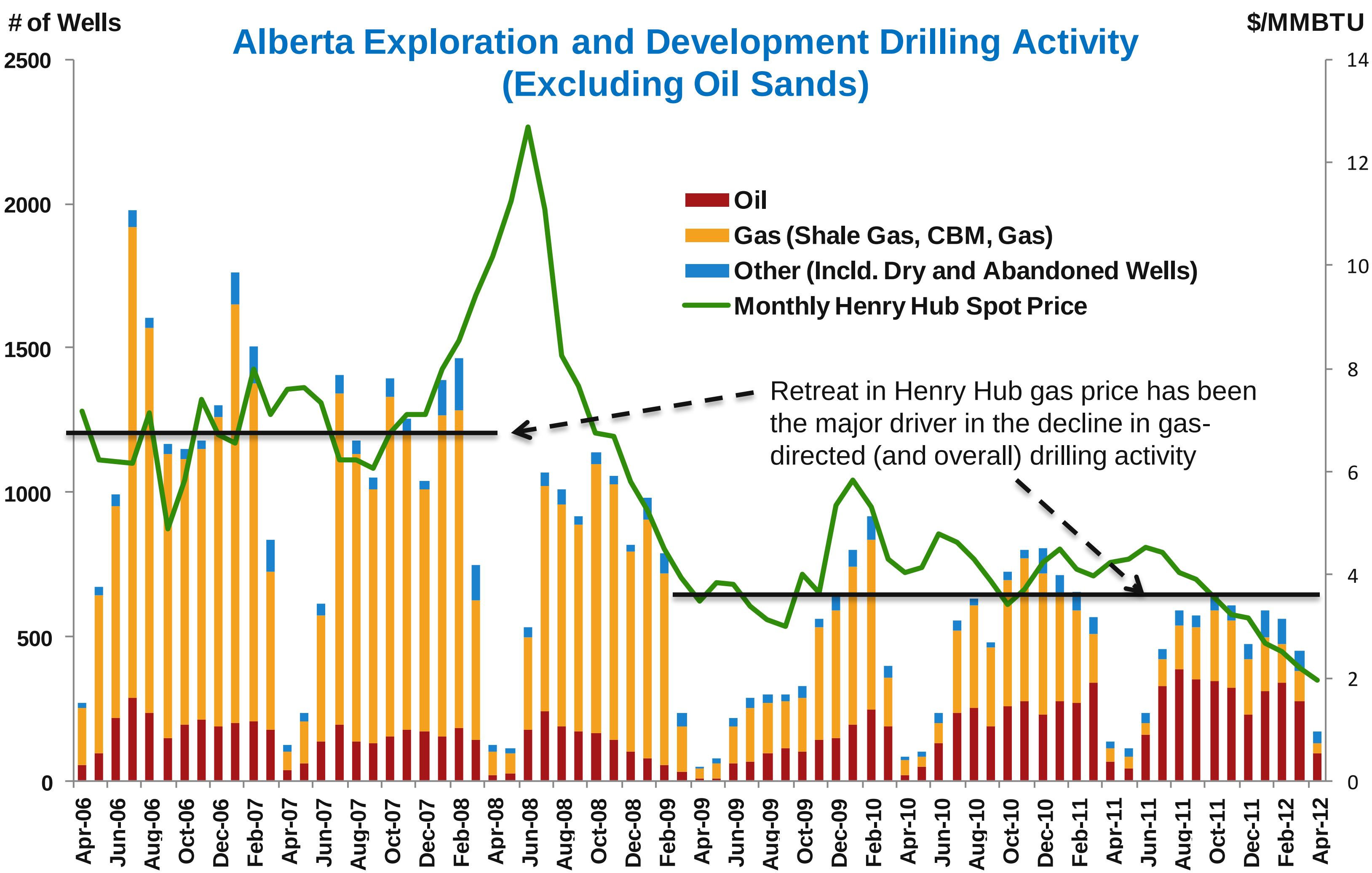
Western Canada Exploration and Development Drilling



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Summary Comments

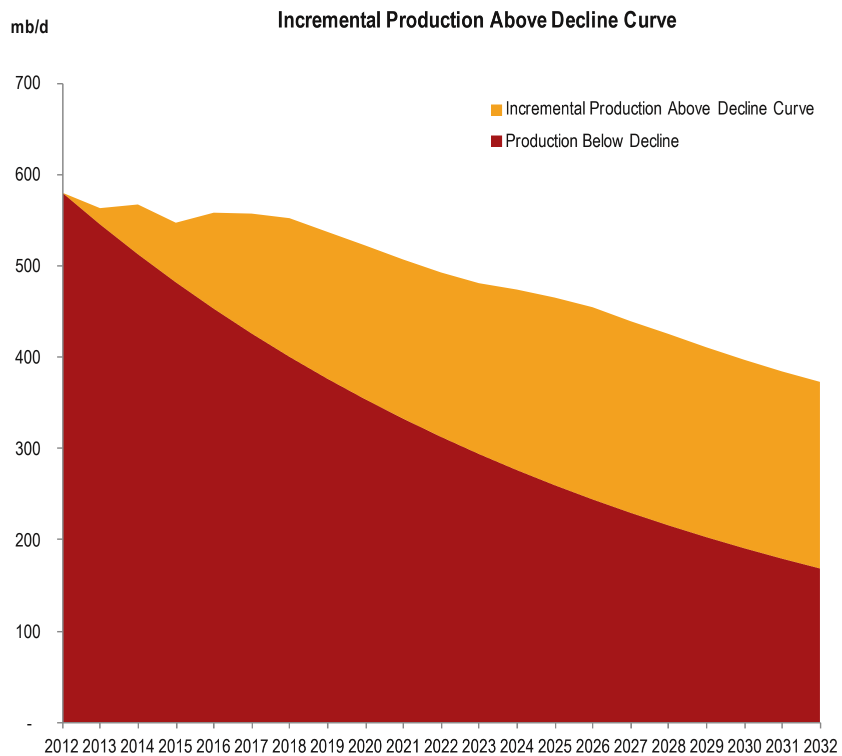
- There is no disputing that upstream E&P activity responds to changes in fiscal terms. All else being equal, E&P companies will allocate their upstream investment dollars to those opportunities likely to deliver the highest return to capital employed.
- However, as seen in the case of Alberta/Western Canada, upstream E&P activity responds most to movements in crude oil and natural gas prices.
  - In Western Canada in general, and Alberta specifically, the greatest impact on upstream activity levels has come from the sharp and continuing decline in natural gas prices
  - Exploration expenditures ramped up sharply in BC and Saskatchewan in 2007-2008, coincident with a shift in fiscal terms in favor of the Alberta government. This particularly ill-timed fiscal change coincided with the maturing of shale oil and shale gas development technologies in the US Onshore basins, which manifested in the large land lease expenditures directed to the Horn River/Montney shale gas plays in northeast BC and Exshaw/Bakken shale oil play in southern Saskatchewan
- Alberta's reduced fiscal burden meant that it was very well positioned to compete for investment when economic activity in the Canadian upstream sector improved.
  - This can particularly be seen by the dramatic shifts in land lease sales revenues in Alberta in recent years
  - The impact on actual drilling activity has been more muted, however, because of the adverse impact of low North American gas prices

Fiscal Regimes Rewarding Incremental Production: Applicability to Alaska

Incremental Production Contracts

Concept

- The main form of fiscal regime existing today that explicitly incentivizes incremental volumes is one that is contractual, rather than based on the tax/royalty system, as Alaska's fiscal regime is. Incremental Production Contracts generally involve compensation to the contractor for incremental volumes produced above an agreed base decline curve for the field/horizon in question



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Incremental Production Contracts

Structure:

- These contracts are often structured as a Services Contract, but may also be structured as a variation on the Production Sharing Contract (PSC).
  - In the former case, a contractor would receive a fixed per-barrel fee, covering all costs incurred by the contractor including a return to capital invested. The contractor may be paid this per-barrel fee regardless of actual volume produced, or in some cases there may be a penalty clause linking the fee to a minimum target volume, and reducing it if this volume is not met
  - In the latter case, a variation on the typical “cost oil:profit oil” structure of the PSC will see the contractor receiving a disproportionate share of the revenue generated from incremental production until recovery of agreed capital costs.
  - In either case, the contractor and government negotiate a “base decline curve” that represents an agreement between the parties regarding the decline rate which would have prevailed under a “sustaining capital” scenario, in which the contractor undertook only those capital expenditures required to maintain operation of the infrastructure, processing facilities, and other installations required for continued field production. The base decline rate is ideally determined through a detailed technical analysis of the production history of the overall field and individual well performance, however in many regimes, a far simpler measure is used. In Iraq, for instance, a uniform 5% decline is applied to all fields, in assessing incremental production.
  - The parties then agree on the amount to be received by the contractor for each barrel of production above that specified by the “base decline curve”, with said amount containing some incentive value to encourage the investment of risk capital

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Incremental Production Contracts (cont'd)

Considerations:

- These types of agreements remain fairly rare in the global E&P sector, for a variety of reasons:
  - In almost all cases, these contracts apply to large, mature field developments and are arrived at following, or as a part of, a change in ownership and operatorship. It is still rare for operating companies to relinquish fields of this type, although it is expected to become more common as the global oil sector matures;
  - The negotiation and agreement on a base decline curve for a given field or asset is highly technical in nature, with the operator having a distinct negotiating advantage based on their knowledge of reservoir fluid properties and sweep response;
  - There are relatively few E&P companies that have experience in enhanced recovery applications to large oil fields, as well as the capital to execute these programs.

Incremental Production Contracts (cont'd)

Examples:

- Mukhaizna field in Oman: Occidental was awarded the Mukhaizna field EOR project by the Oman government as part of a relinquishment of the Block 6 concession area (covering essentially all of onshore Oman), held since the 1940s by a consortium headed by Shell.
  - Under the agreement, Occidental receives an incentive for each barrel of incremental production above a negotiated Base Decline Curve, with the requirement that gross production be increased from the ~15 mbo/d when the field was secured in 2004, to a target 150 mbo/d by 2015. Occidental has been successful in growing Mukhaizna volumes to an exit-2011 level of ~126 mbo/d, and is on track to reach the target production level in 2013-2014.
- Iraqi field reactivation projects: In recent years, Iraq has sought to involve technically advanced international oil & gas companies in the revitalization of their large, mature oil fields through the use of Technical Service Agreements, based on an incremental production approach.
  - Companies are compensated with a fixed fee (for example $2/bbl) for all production above the initial production rate of the field (which is declined at 5% each year in setting the base for incremental production).
  - Companies must also negotiate an increased production target, to be sustained for a plateau period of seven years, and may have their remuneration fee reduced if they do not achieve their performance targets.
  - At the Rumaila field, BP has been successful in increasing production from the 1,066 mboe/d initial rate, and appears on track to reach the 2,850 mboe/d target plateau rate by the end of the decade

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Other Incremental Production Incentives

- Mature oil fields, Colombia: The fiscal changes introduced in Colombia in 2002 were designed to accelerate production from mature oil fields, but to do so in the context of a tax/royalty system, rather than a contractual system
  - Since the aim was to incentivize increased production from mature fields, which were largely smaller production fields, the government replaced the previous flat 20% royalty with a sliding royalty from 8% to 20% for all fields producing below 125 mbo/d.
  - In effect, the fiscal change increased the return to each barrel of production below the 125 mbo/d ceiling, including on each incremental barrel added. The impact on the Colombia oil sector has been substantial, with production increasing from a plateau of ~600 mbo/d over the 2003-2006 period to above 800 mbo/d by 2010.

Application to Alaska

- Alaska has a well-established tax royalty system, rather than the contractual system that applies in most regimes that explicitly reward incremental production.
  - The broad, volume-oriented approach taken in Colombia may not be well suited to the Alaska situation, where the Government is looking to target near- and medium-term production response from a small number of large, mature fields, as opposed to mature basin areas with large numbers of relatively small producing fields.
- In general, regimes that have used incremental production contracts have done so when a large, mature asset, producing well below its potential, is changing ownership
  - In such cases, since the new owners did not invest the capital required to deliver past and current production levels, they may be amenable to an asset acquisition negotiation in which their remuneration is tied to the incremental production they are able to provide above an agreed base. The original asset owner would likely find such an approach untenable, as it is in their interest to continue to leverage past capital investment to the greatest extent possible.
  - Such contracts have been used in places like Iraq to attract technically advanced international companies to the redevelopment of fields that have either been neglected by years of under-investment and poor management by National Oil Companies, or damaged through extended periods of internal strife. They are also gaining traction in jurisdictions where foreign ownership of oil and gas resources is considered untenable (or in some cases, unconstitutional).

Application to Alaska (cont'd)

- While the structure of such incremental production contracts may not be suited to Alaska, the basic concept of incentives for incremental production over a decline curve may be differently applied to Alaska's tax/royalty system
  - Rather than specifying some type of differentiated, per barrel fee or price for production above a decline curve, other incentives—in the form of significantly reduced tax rates—could be applied to incremental volumes, thereby retaining the price-based tax/royalty foundation of the current fiscal system
  - Ideally, the decline curve itself would be set similarly to that in an Incremental Production Contract, on the basis of a technical analysis to determine the decline rate which would prevail under a "sustaining capital only" scenario. Failing that, a rate based more broadly on historical declines could be agreed.
- There are a number of factors that could favor the use of such an Incremental Production approach in Alaska:
  - Relatively small number of mature oil fields that would be candidates for this type of arrangement. These could be pared even further by establishing a minimum threshold size for eligibility;
  - There are precedents for establishment of base field decline rates, most common being actual historical production;
  - The incumbents (effectively BP, COP, and XOM) all possess the capital and expertise to execute on this type of aggressive enhanced recovery initiative;
  - In the immediate term (3-5 years), the focus of Alaska fiscal policy is by necessity on increased production from its legacy fields, as new source volumes are not sufficient to redress the decline in oil production within this window
  - An incremental production approach could provide an alternative, or a complement, to a uniform lowering of government take, if the aim is to ensure that improved investment terms are specifically tied to increased investment

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Responses to Miscellaneous Additional Questions

Incentivizing New Wells From Existing Well Bores vs New Wells From Surface

- Drilling from existing well bores involves:
  - Deepening of the existing well. This is done to access a reservoir horizon in the same vertical well location but at a lower depth.
  - Drilling horizontal wells from existing vertical wells. Horizontal wells access a larger area of the reservoir, offering a significant improvement in production over vertical wells but at a greater cost in terms of drilling and reservoir stimulation (fraccing). By re-entering existing vertical wells, these incremental drilling costs can be minimized.
  - Drilling side track wells from existing wells (often termed "slant drilling") to access a reservoir area not accessible from the existing well.

- Drilling new wells from surface involves:
  - Developing a new oil field or developing new areas of an existing field, through either vertical and horizontal wells.
  - Drilling infill wells to reduce spacing between producing wells to (i) improve connectivity between production and injection wells; (ii) enhance or improve reservoir sweep coverage and mechanics; (iii) improve the reserves recovery factor; and/or (iv) reduce field decline.
  - Drilling injection wells and injecting water, solvents, lighter hydrocarbons, etc., in order to maintain reservoir pressure, improve recovery rates, and stem declines.
  - Keeping drilled length the same, new wells from surface are in general more expensive than wells from existing well bores

Both types of well are required under different conditions. Neither is specifically more effective in increasing production.

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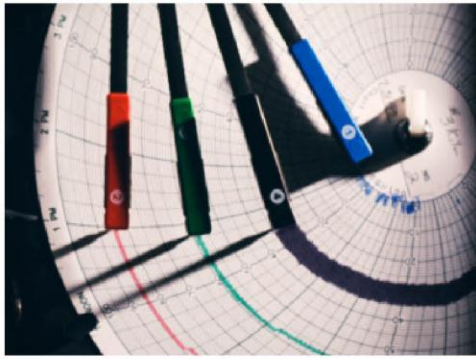

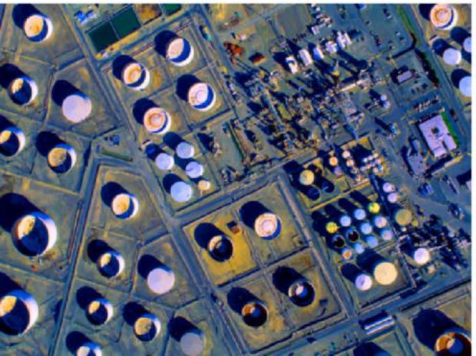

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