Wood Mackenzie

The Impact of Gulf of Mexico-Deepwater Permit Delays on US Oil and Natural Gas Production, Investment, and Government Revenue

December 2010

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Executive Summary

API has retained Wood Mackenzie to estimate the impact of potential permit delays and the subsequent effects due to less favourable project economics on deepwater Gulf of Mexico (GoM) oil and gas development. Wood Mackenzie has estimated the potential production, investment, and government revenue impacts of permit delays that:

- Postpone field start-up one year and delay drilling times by 10%
- Postpone field start-up two years and delay drilling times by 20%

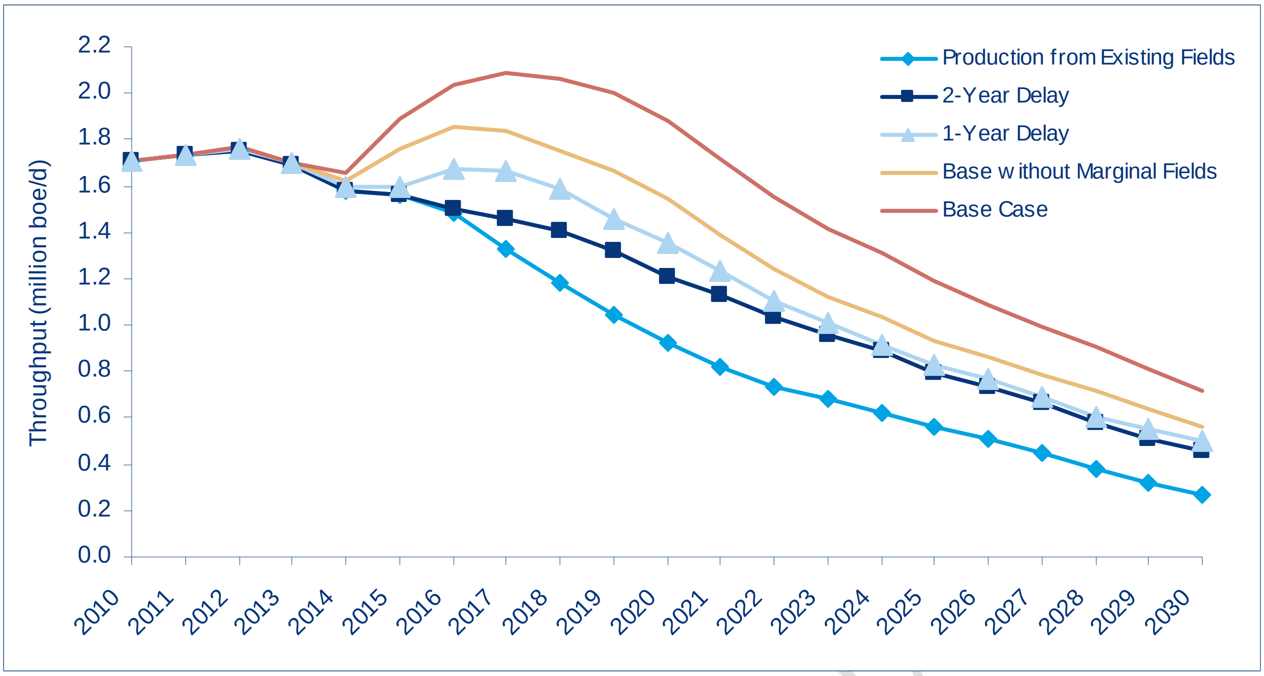
Wood Mackenzie compared its base project economics for 25 identified, but as of yet undeveloped deepwater Gulf of Mexico (GoM) targets to economics under the above mentioned scenarios to determine the potential impact of slower permitting. Wood Mackenzie's expected development scenarios and full-field development economics were calculated using our Global Economic Model (GEM) to determine what impact potential delays have on financial returns in the GoM. The production, investment, and government revenue at risk due to permit delays was calculated using the financial hurdle rate assumptions of 15% nominal internal rate of return (IRR) and 8% nominal IRR for the deeper Lower Tertiary targets.

No cost increases due to permit delays were assumed. While we do not expect permitting delays alone to reach 1-2 years, we expect this to be realistic for total logistical delays possible for field development from the result of slower permitting. Drilling wells and completing production facilities requires the alignment of a wide range of activities, such as delivery and installation of offshore underwater pipeline, equipment and other infrastructure. For example, even delays as short as a few weeks are compounded by each well and can create bottlenecks when planning for rig commitments, support services, and subsequent shipyard commitments, etc.

The potential loss of commercial reserves from fields at risk was found to be substantial. In the Base Case, 10 fields or 1.9 billion barrels of oil equivalent (bnboe) of the 25 fields studied are already sub-economic and will be further at risk under additional development delays. A total of 13 and 17 fields out of 25 fall below the hurdle rate assumptions under the 1-year and 2-year delay scenarios, respectively. The total recoverable reserves attributable to investment falling below the hurdle rates from these two delay cases are 2.7 and 3.1 bnboe out of a total estimate of 5.1 bnboe for all 25 fields in this analysis. There is an estimated total of 12.8 bnboe of GOM deepwater reserves of which 7.7 bnboe is already online or underdevelopment plus 5.12 bnboe from the 25 probable fields.

The potential production volume of new fields that are already at risk in the Base Case reaches a maximum 340,000 boe/d in 2019. In the 1-year delay case, an additional 200,000 boe/d of production is at risk beyond the Base Case for a total at risk volume of 540,000 boe/day. In the 2-year delay case, an additional 340,000 boe/d of production is at risk in 2019 for a total of 680,000 boe/day. The total production volume at risk in 2019 for the 1-year and 2-year scenarios represents 27% and 34% of Base Case throughput for the year.

Deepwater GoM Production Projections



Source: Wood Mackenzie – Upstream Service
1-Year and 2-Year Delay projections assumes that all at-risk fields are not developed.

Over $43 billion of the potential $105 billion in investment spending from these 25 probable field developments over the next 20 years could already be at risk. Development delays of 1-year potentially increase this amount at risk by $16.5 billion to total investment at risk of $59.6 billion. A delay of 2 years increases potential investment at risk by $27.4 billion over the Base Case or a total of $70.5 billion at risk. The majority of the lost investments would occur from 2011-2020.

Projected Impact of Lower Development Levels

	New Field Reserves (bnboe)			New Field Investment (billions $2010)			Government Revenue (billions $2010)		
	Economic	Total at Risk	Incr. Risk to Base	Economic	Total at Risk	Incr. Risk to Base	Economic	Total at Risk	Incr. Risk to Base
Base Case Projection	5.1	-	-	$105.0	-	-	$24.5	-	-
Base less Marginal Fields	3.2	1.9	-	$61.9	$43.1	-	$16.3	$8.2	-
1-Year Delay	2.4	2.7	0.8	$45.4	$59.6	$16.5	$10.8	$13.7	$5.5
2-Year Delay	2.0	3.1	1.2	$34.5	$70.5	$27.4	$7.4	$17.1	$8.9

Source: Wood Mackenzie – Upstream Service

Government revenue would also be correspondingly lower as fewer developments meet required levels of return. We estimate that potential government revenue at risk in the Base Case from royalty and corporate tax over the life of the projects is $8.2 billion. A 1-year delay in development would increase the potential loss of government revenue by an additional $5.5 billion or to a total loss of $13.7 billion. A 2-year delay in project development times increases the amount by $8.9 billion to a total amount of government revenue at risk of $17.1 billion.

Some of the sub-economic fields identified in this analysis will still be developed, albeit with lower returns than initially planned mainly due to the sunk lease and exploration costs that have already been incurred. However, the analysis indicates that approximately two-thirds of known probable discoveries in the deepwater GoM could fall below our economic thresholds on a full-cycle basis if significant permitting delays occur. The results indicate the future of exploration in the GoM is very uncertain. Many high-risk and deep targets in the frontier and emerging plays may not be explored if only marginal returns are expected. Most of these types of targets were projected to provide much of the expected growth in the GoM. Significant increases in development costs, which were not part of this analysis, will further reduce the potential economic viability of the deepwater GoM.

While regulatory changes and more detailed Application for Permit to Drill (APD) procedures are expected, our analysis isolates timing and suggests any policy that increases development time should be weighed carefully. Much of the deepwater GoM is marginal under a one and two year field start-up delay and further uncertainty increases the commercial risks of major projects in the deepwater.

1. Background and Study Objectives

Wood Mackenzie has been appointed by the American Petroleum Institute (API) to provide an evaluation of potential impact on production, investment, and government revenue caused by permitting delays in the Gulf of Mexico.

Background

The API, on behalf of its members, is concerned with, and would like to assess the potential impact of permit delays on future production, investment, and government revenue in the deepwater GoM. In particular, API contracted Wood Mackenzie to provide an independent view of the future oil and gas field developments at risk as a result of increased lead times.

Wood Mackenzie considered two scenarios where lead times are increased by one and two years. It is important to note that permitting delays create logistical issues in which any time period as short as a few weeks per well could impact a full appraisal or development program by months to years depending on the scale of the project. As a consequence, production is delayed or potentially lost, which in turn impacts the country's energy security.

We understand that API will use this analysis to inform policy makers and regulatory bodies to the impacts of potential permitting delays. Furthermore, we understand the analysis developed in this study by Wood Mackenzie will be presented in a way to preserve its objectivity.

Study Objectives

- Provide an updated full-cycle view of the current probable field developments in the GoM using standard economic metrics derived from Wood Mackenzie's Global Economic Model (GEM) and a baseline of anticipated production, investment, and government revenue through 2030.
- Compare full-cycle financial returns for twenty-five probable field developments in Wood Mackenzie's Upstream Service. The project will provide full-cycle post-tax IRR and NPV_{10} for all fields under the following cases that will be built accordingly:
    - Base Case: Post-Deepwater Horizon Incident including estimates for exploration and appraisal costs
    - a 1-year time delay in field start-up relative to the Base Case, and a delay in bringing wells to production
    - a 2-year time delay in field start-up relative to the Base Case, and a delay in bringing wells to production
- Full-cycle returns will then be used to estimate the volumes of production and reserves, as well as government revenue and total value creation at-risk under the two scenarios using defined financial parameters.

2. Methodology

Process

- Wood Mackenzie used its proprietary Upstream Database of oil and gas fields and plays, which enabled us to isolate probable field developments in the GoM. Models were updated to consider the current environment and provide a Base Case view of fields. We considered signature bonuses as well as exploration and appraisal costs with each field to build full-cycle models that utilized our understanding of the regulatory, fiscal, and technical environment of probable developments.
- Models were built for fields using the post-Macondo safety regulations, estimated exploration and appraisal costs, development costs, and operating costs to calculate a base IRR and NPV for comparison with the following sensitivities:
    - Base Case: Probable developments were updated with current expectations for timing, added costs estimated by the BOEMRE, as well as exploration and appraisal costs
    - 1 year delay: Base Case probable developments with an added one year start-up delay and a 10% increase in time for bringing development wells to production
    - 2 year delay: Base Case probable developments with an added two year start-up delay and a 20% increase in time for bringing development wells to production
- All scenarios, including the Base Case, assume only the $1.42 million/well estimate of increased safety related costs provided by BOEMRE. Any additional costs beyond that amount were excluded in this analysis to isolate the issue of timing.
- Prior to running these two scenarios, models were built for expected future development in the GoM
    - 25 probable field developments were modelled with updated production profiles and associated capital and operating costs
    - Production and Costs were sourced from our Upstream Database and GEM
- After the review of our models was complete, the following was generated under the three scenarios:
    - IRR (Post Tax)
    - Expected Government Revenue (Royalty and Income Tax)
    - Total Value Creation (Government Revenue + Post-tax PV10 of each field)
- The analysis of this data determined which of the potential future developments would become sub-economic using a financial hurdle rate of 8% nominal IRR for Lower Tertiary prospects and 15% nominal IRR for all other prospects.
- Sub-economic fields may still be developed for strategic reasons or if a significant amount of leasing and exploration costs have previously been incurred. However, the risk of a field not being developed increases as the IRR falls further below the financial hurdle rates.
- Once the sub-economic fields were identified in each scenario, the impact on production, investment, government revenue, and total value creation were calculated.
- Production for existing or already underdevelopment fields is not altered in any of the cases.
- This methodology assumes companies will cease investment if returns fall below our accepted level under our Base Case pricing assumptions.
- Wood Mackenzie utilized its WTI crude oil planning price assumptions of $87.40 / barrel in 2011, $83.50 in 2012, $81.18 in 2013, $82.81 in 2014, and $84.46 in 2015, inflating thereafter.

Fields and Play identification

Wood Mackenzie identified 25 different fields for evaluation in this study. Eight of these fields target hydrocarbons in the Lower Tertiary play while the remaining fields target more shallow, geologically younger plays. The fields were discovered between 1996 and 2009 with total estimated recoverable reserves of over 5.1 billion barrels of oil equivalent. Individual field size ranges from as low as 9.5 million boe (mmboe) to over 560 mmboe. Under Wood Mackenzie's Base Case projections, these fields are anticipated to come onstream between 2011 and 2019.

3. Permit Delays

Permit delays directly impact the pace of development of US energy resources. Even a small delay will be multiplied by the number of wells needed to explore, appraise, and develop a field. These delays can be further compounded by the difficulty in securing rigs, other services (e.g. skilled manpower, specialized vessels for installing infrastructure), and subsequent shipyard commitments. While actual permit delays could be a matter of weeks for each well, delays could easily be compounded into months or years, particularly for large, capital intensive projects.

4. Impact of Delays

4.1 Scope of consideration

Wood Mackenzie analyzed 25 identified, but undeveloped, deepwater GoM fields that Wood Mackenzie had classified as probable for development before 2020. All of these fields are included in Wood Mackenzie's Base Case forecast for the GoM. The following analysis was undertaken for each field under assumptions detailed in the Methodology portion of this report.

4.2 Economic results

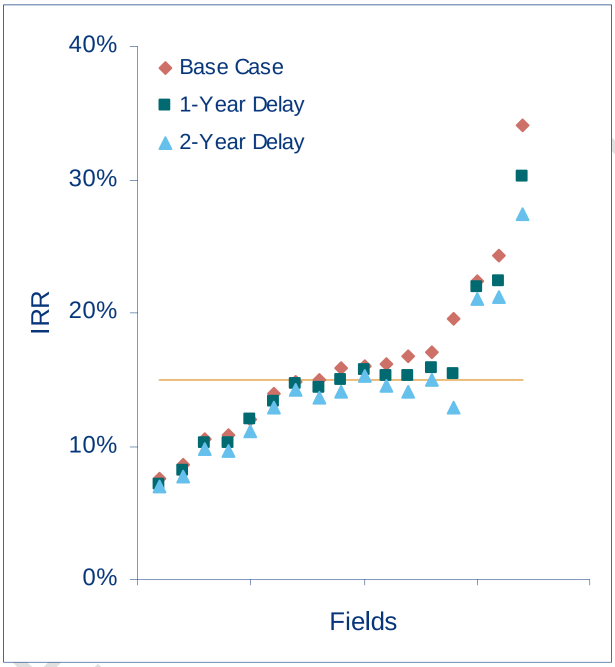
For the Gulf of Mexico, Wood Mackenzie considered full-field economics of probable developments, which includes an apportioned signing bonus, as well as exploration and appraisal costs.

Under our Base Case models, the internal rate of return ranged between 7% and 11% for the Lower Tertiary fields and between 8% and 34% for all other fields. In the Base Case, a total of 10 fields (four Lower Tertiary and six Other) already fall below the financial hurdle rate assumptions of 8% and 15%, respectively. The 10 fields have a total estimated reserves of 1.88 bnboe or 37% of the total reserves of the 25 fields analyzed. These marginal fields would be put at further risk of not being developed with permitting delays assumed under the 1-year and 2-year delay scenarios.

Under the 1-year delay assumptions, a total of 13 fields (five Lower Tertiary and eight Other) fell below the hurdle rate assumptions. The total recoverable reserves from these fields is 2.7 billion boe (bnboe) or more than 52% of probable reserves. Furthermore, under the 2-year delay assumptions, a total of 17 fields (five Lower Tertiary and 12 Other) with combined recoverable reserves of 3.1 bnboe fell below the hurdle rate assumptions. This amounts to 61% of the probable fields analyzed or 24% of Wood Mackenzie's 12.77 bnboe total estimate of remaining commercial reserves (onstream, under-development, and probables) in the deepwater GoM. Further impacts would be expected to yet-to-find (YTF) reserves.

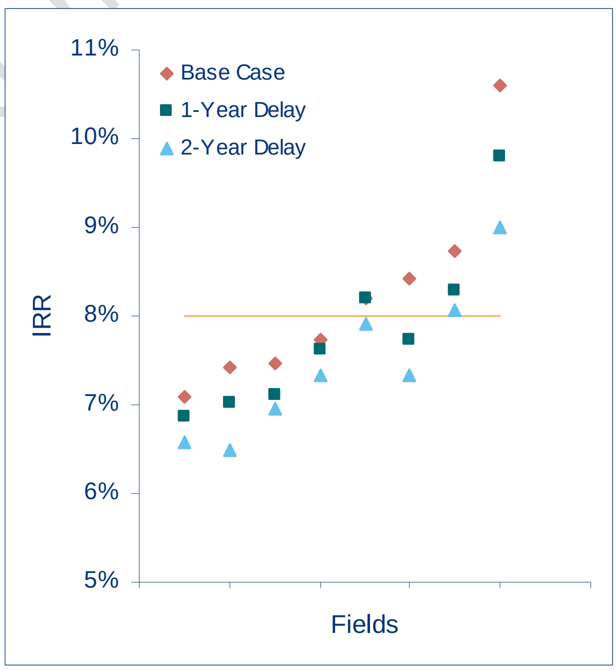
Five of the top six performing fields are subsea tiebacks and require significantly less capital investment to bring online. The fields provide the most attractive returns, but are highly sensitive to time and cost delays. In comparison, fields ranking lowest all assume a stand-alone development and target more challenging reservoirs (e.g. Lower Tertiary and subsalt Miocene which can be high-pressure or high-temperature). As such, these projects require a dedicated facility, long drilling times, cutting edge completions technology, as well as additional maintenance and operating expenses.

Deepwater GoM IRR (except Lower Tertiary)



Source: Wood Mackenzie – Upstream Service, GEM

Lower Tertiary Fields IRR[1]



Source: Wood Mackenzie – Upstream Service, GEM

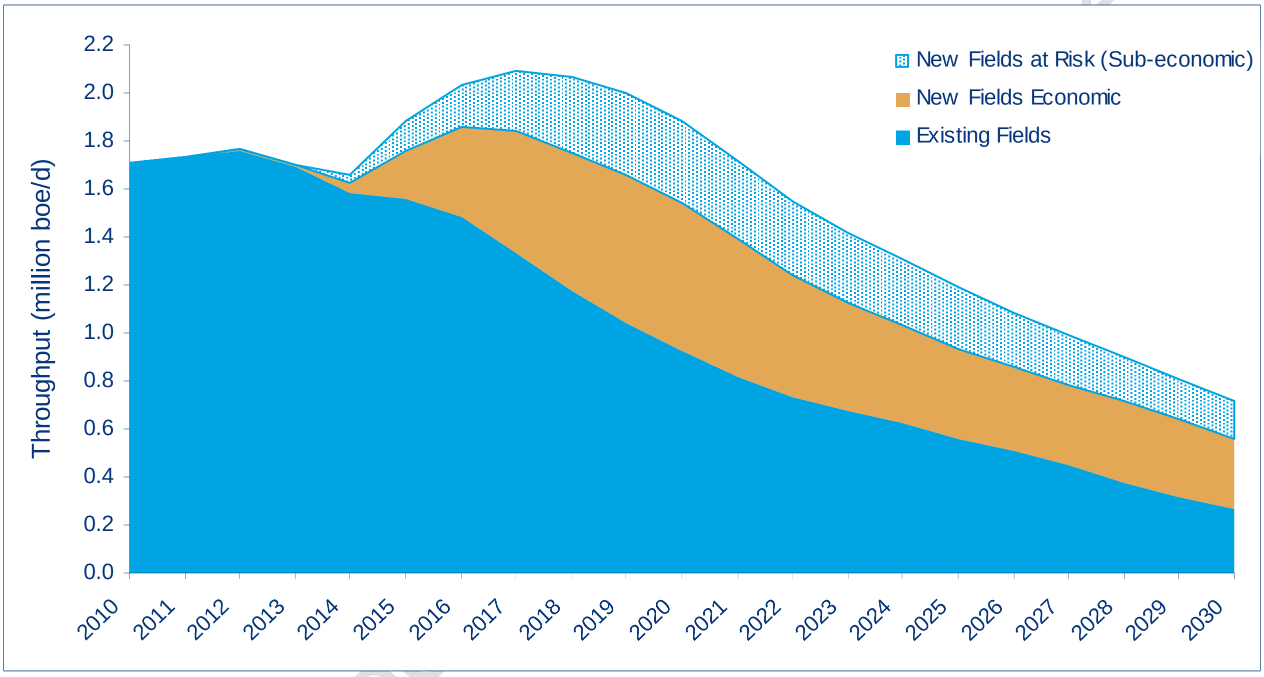
[1] A total of six Lower Tertiary Fields fall below the 8% IRR threshold, but one of the six is being developed in parallel to a field that yields an IRR greater than 8%. The combined IRR of the two projects is greater than 8%.

4.3 Production under full-cycle consideration

Under Wood Mackenzie's current Base Case, the Deepwater GoM is expected to resume production growth as operators re-commence development of probable fields. Wood Mackenzie's currently onstream and underdevelopment deepwater fields are expected to peak in 2012 with throughput at 1.75 million boe per day (mmboe/d). The probable portfolio of fields (25 in total), the scope of this study, brings a new peak in 2017 at around 2.1 mmboe/d under our Base Case assumptions. The probable fields reach a peak in 2019 adding 0.95 mmboe/d to the declining currently onstream and underdevelopment fields. Under the Base Case scenario where marginal fields are not developed, peak production is reached in 2016 at 1.86 mmboe/d and production from probable fields reaches a maximum at 0.62 mmboe/d in 2019. At risk production from the sub-economic fields reaches a maximum of 0.34 mmboe/d in 2019.

Investment decisions often consider only future costs and revenues. Therefore, developments with "full-cycle" investment returns that are classified as "at risk" in which very little spending has occurred are more likely not to be developed relative to projects with significant sunk costs.

Estimated Deepwater GoM Production (Base Case)

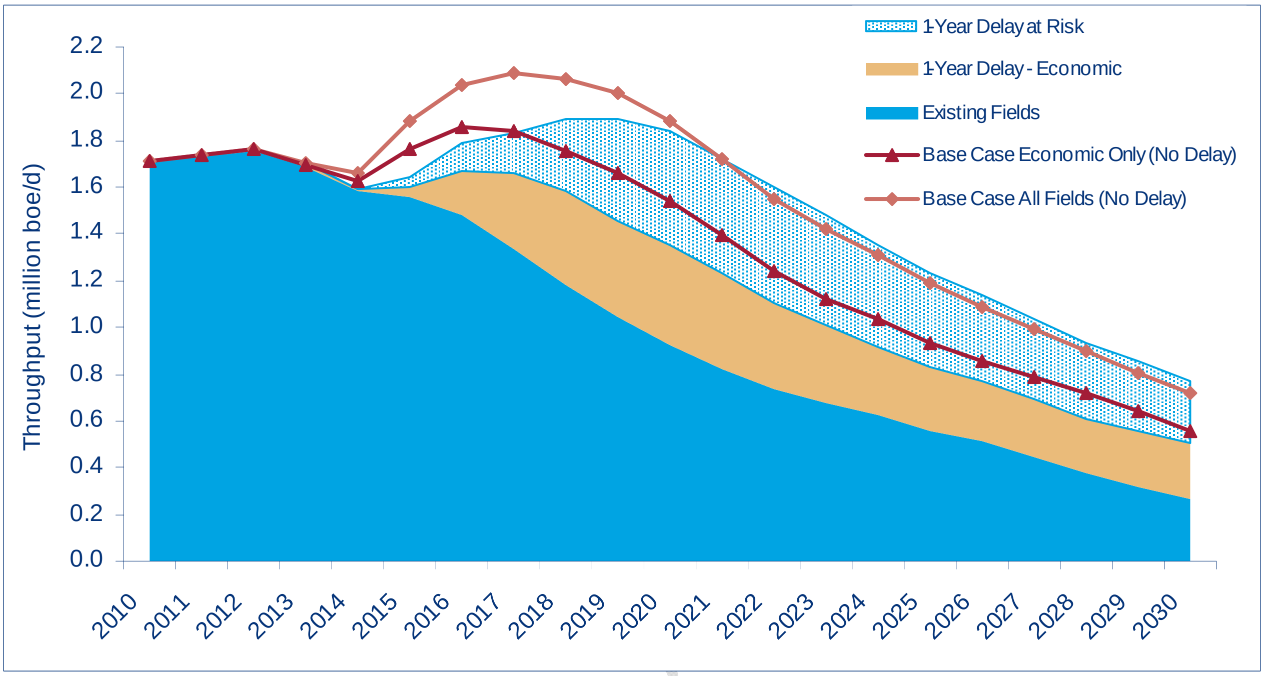


Source: Wood Mackenzie – Upstream Service

1-Year Delay Scenario

Assuming the 13 sub-economic fields in the 1-year delay scenario are not developed, production is pushed out further. The peak from currently onstream and underdevelopment fields in 2012 is not surpassed despite the additional supply from the 12 probable fields that exceed the economic hurdle rates. Maximum production at risk relative to the Base Case projection occurs in 2019 at a volume of 540,000 boe/d. This production at risk level is 200,000 boe/d greater than the level in the Base Case.

Estimated Deepwater GoM Production (1-Year Delay Case)

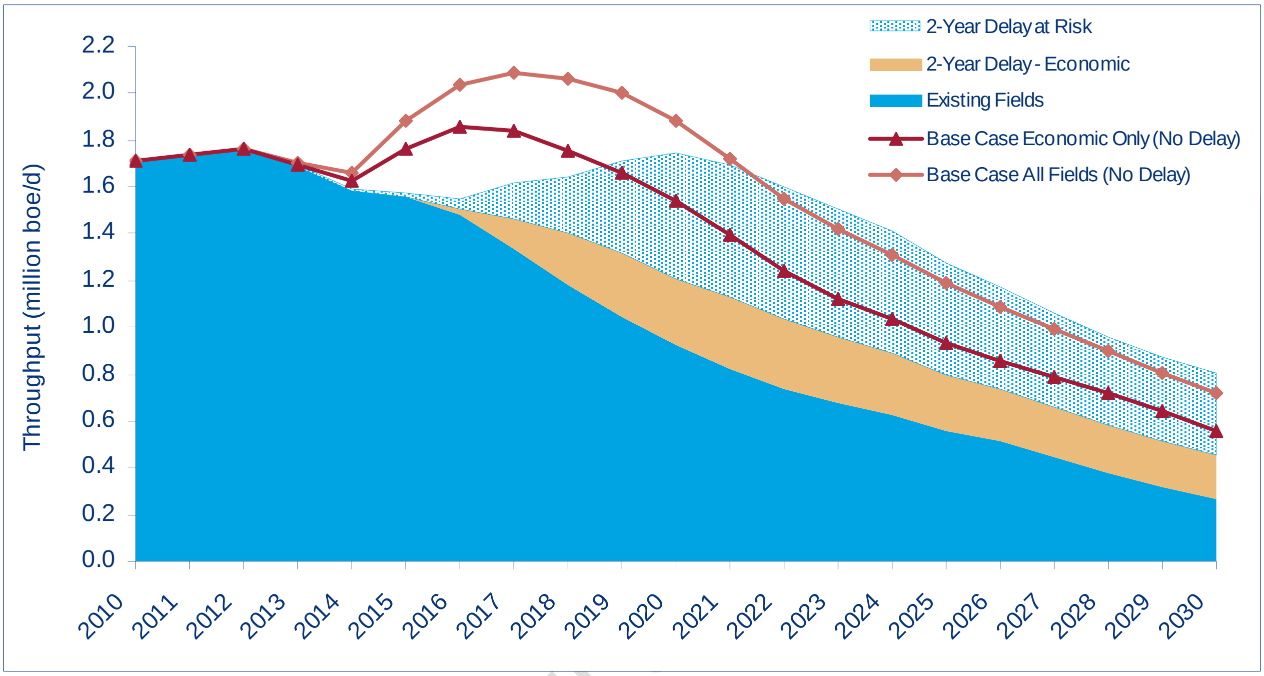


Source: Wood Mackenzie – Upstream Service

2-Year Delay Scenario

Under a 2-year delay scenario, peak production in 2012 from currently onstream and underdevelopment fields would never be exceeded even if all 25 projects are developed – the throughput would only reach a similar production level (of 2012) in 2019. Assuming the fields that fall below our hurdle rates are not developed, the decline from currently onstream and underdevelopment fields is never reversed. Maximum production at risk relative to the Base Case projection occurs in 2019 at a volume of 680,000 boe/d. This production at risk level is 340,000 boe/d greater than the level in the Base Case.

Estimated Deepwater GoM Production (2-Year Delay Case)

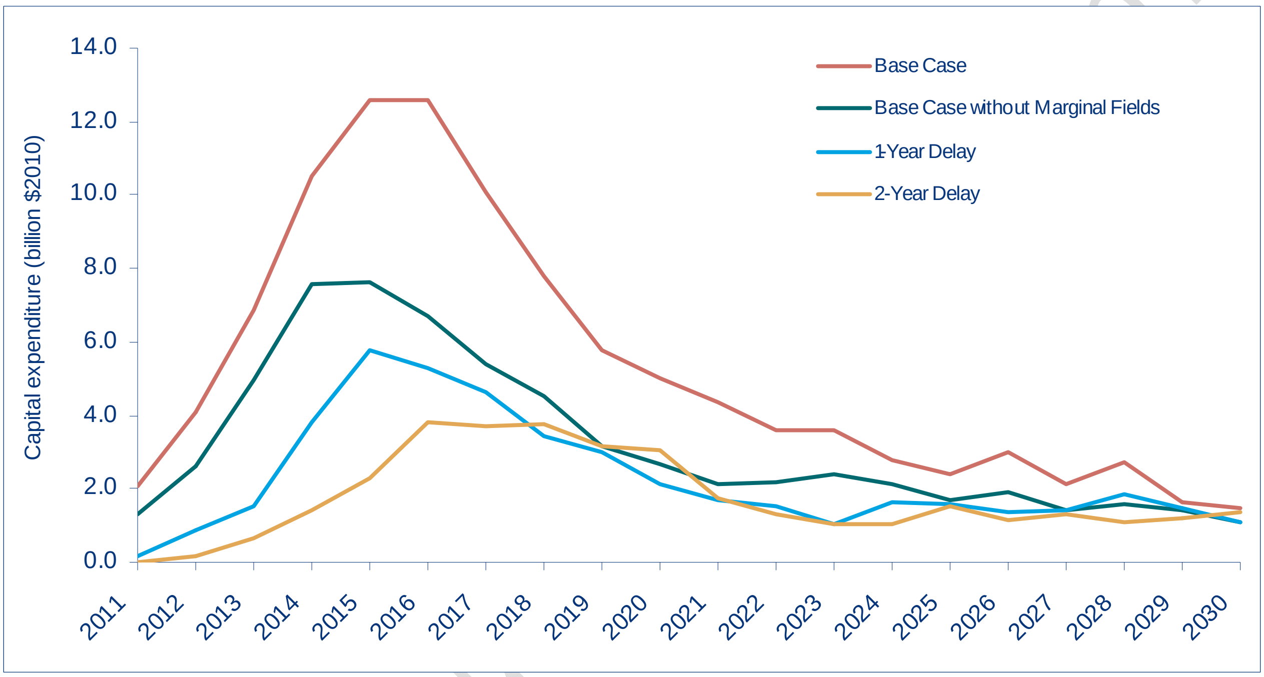


Source: Wood Mackenzie – Upstream Service

4.4 Investment

Under our Base Case assumptions, we estimate that a total of $105 billion will be invested over the next 20 years (between 2011 and 2030, inclusive) to develop the 25 probable fields. Total investment that is currently at risk under the Base Case is $43 Billion. Potential delays in development will only increase the risk of this investment not going forward. Approximately $60 billion of the total investment does not meet our financial hurdle rate under our 1-year delay assumptions. The already marginal fields are largely Lower Tertiary and subsalt Miocene, which can be technically challenging and are the most capital intensive projects in the GoM. As such, the impact from these projects on investment levels is substantial. Total capital expenditure falling below our hurdle rates over the same time period (next 20 years) increases to over $70 billion under our 2-year delay assumptions, or 67% of the Base Case. The at-risk investment is higher in the near-term as most of these projects are assumed to start development over the next five years.

Gulf of Mexico Projected New Field Investments[2]



Source: Wood Mackenzie – Upstream Service

[2] In 2020, the higher investment levels in the 2-year delay scenario relative to the 1-year delay scenario are due strictly to additional project delay. Total number of projects and investment spending is greater in the 1-year scenario.

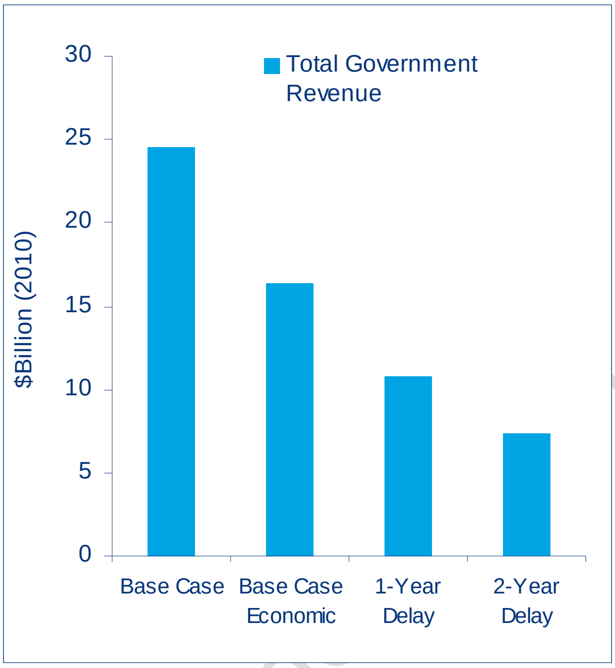
4.5 Government Revenue and Total Value Creation

The delays in timing and subsequent investment decisions will not only impact oil and gas companies, but it will also lower government revenue and total economic value created from the Deepwater GoM.

Total government revenue (tax and royalty) over the life of the 25 fields in the Base Case is estimated at $24.5 billion in 2010 dollars. Government revenue in the Base Case is estimated to drop to $16.3 billion if none of the sub-economic fields are developed. Government revenue would further decrease to $10.8 billion or less than 50% of full Base Case levels if investments that do not reach the hurdle rates drop out under 1-year delay assumptions. Revenue drops 70% to $7.4 billion if investments that do not reach the hurdle rates drop out under the 2-year delay assumptions.

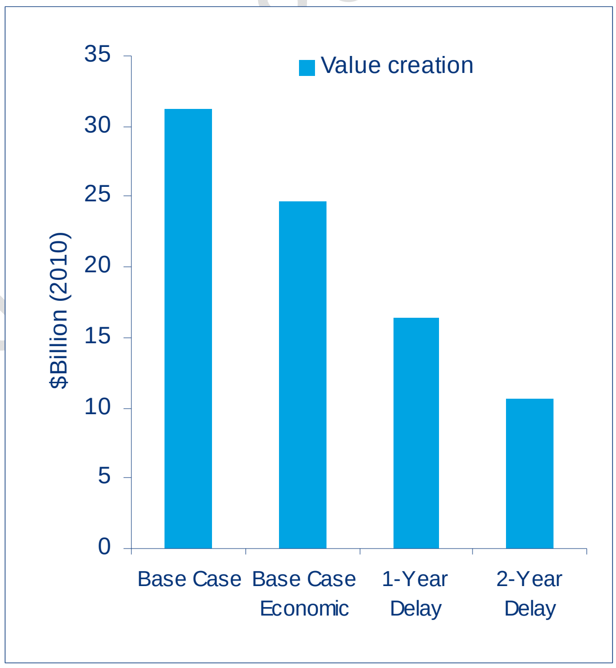
Value creation, which is a combined result of government and corporate take, is also reduced substantially using the two cases of permitting delays. The total net present value (NPV10) of the 25 fields is reduced by 47% (to US$16.4 billion) using 1-year delay assumptions and 66% (to $10.6 billion) using 2-year delay assumptions from the Base Case value of $31.2 billion. The total project value in the Base Case for fields that meet the full cycle financial hurdle rates is $24.6 billion.

Estimated Total Government Revenue (New Fields) Life of Projects (Non Discounted)



Source: Wood Mackenzie – Upstream Service, GEM

Estimated Total Project Value Created Life of Projects (NPV at 10%)



Source: Wood Mackenzie – Upstream Service, GEM

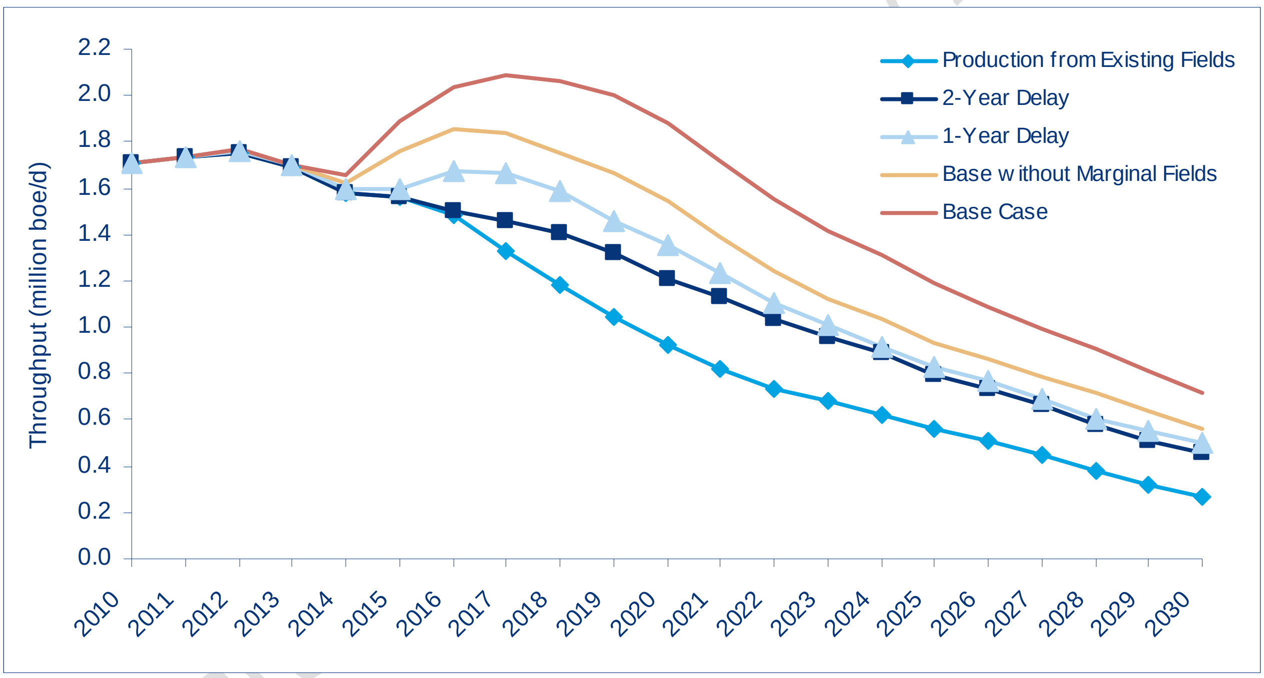
5. Summary

5.1 Summary of findings

The potential impact of permitting delays was found to be substantial. In the Base Case, 10 fields of the 25 fields studied are already sub-economic under a full cycle investment analysis and will be further at risk under any additional development delays. A total of 13 and 17 fields out of the 25 fields studied were found to fall below the financial hurdle rate assumptions using the 1-year and 2-year delay cases, respectively. The total recoverable commercial reserves attributable to return on investment falling below the hurdle rates in the Base Case is 1.9 bbnboe out of total probable new field reserves of 5.1 bnboe. Sub-economic reserves in the two delay cases are 2.7 and 3.1 bnboe respectively. Total deepwater GoM recoverable reserves from known discoveries are estimated at 12.8 bnboe. While the realized impact is highly dependent upon the breakeven hurdle rate assumption, we find that the impact of permitting delays and subsequent persistent delay in development drilling can be substantial.

The potential production volume of new fields that are already at risk in the Base Case reaches a maximum 340,000 boe/d in 2019. The at risk production volume difference using the 1-year delay assumptions is also greatest in 2019 at 540,000 boe/d or 200,000 greater than at risk volumes in the Base Case. This production level equates to 27% of Base Case throughput for the year. Similarly, maximum potential lost production using the 2-year delay assumptions adds an additional 340,000 boe/d of production at risk in 2019 for a total of 680,000 boe/day, over 34% of Base Case throughput for the year. In the 2-year delay case, production never reaches the peak expected production in 2012 under our Base Case.

Deepwater GoM Production Projections



Source: Wood Mackenzie – Upstream Service

Over $43 billion of the potential $105 billion in investment spending from these 25 probable field developments over the next 20 years could already be at risk. Development delays of 1-year potentially increase this amount at risk by $16.5 billion to total investment at risk of $59.6 billion. A delay of 2 years increases potential investment at risk by $27.4 billion over the base or a total of $70.5 billion at risk. The majority of the lost investments would occur from 2011-2020.

Estimated Impact of Lower Development Levels

	New Field Reserves (bnboe)			New Field Investment (billions $2010)			Government Revenue (billions $2010)		
	Economic	Total at Risk	Incr. Risk to Base	Economic	Total at Risk	Incr. Risk to Base	Economic	Total at Risk	Incr. Risk to Base
Base Case Projection	5.1	-	-	$105.0	-	-	$24.5	-	-
Base less Marginal Fields	3.2	1.9	-	$61.9	$43.1	-	$16.3	$8.2	-
1-Year Delay	2.4	2.7	0.8	$45.4	$59.6	$16.5	$10.8	$13.7	$5.5
2-Year Delay	2.0	3.1	1.2	$34.5	$70.5	$27.4	$7.4	$17.1	$8.9

Source: Wood Mackenzie – Upstream Service

Government revenue could be substantially less if projects are cancelled from impacts of permitting delay as fewer developments meet required levels of return. We estimate that potential government revenue at risk in the Base Case from lost royalty and corporate tax over the life of the projects is $8.2 billion. A 1-year delay in development would increase the potential loss of government revenue by an additional $5.5 billion or to a total loss of $13.7 billion. A 2-year delay in project development times increases the amount by $8.9 billion to a total amount of government revenue at risk of $17.1 billion.

While estimating future investment decisions is very difficult, the hurdle rates were chosen for consistency, but investment decisions will also be influenced by factors not considered in financial returns. Strategic decisions undertaken by operators and long-term commodity price outlooks could materially impact these estimates.

5.2 Conclusions

While further regulation and more detailed applications for permit to drill (APD) procedures are expected in the future, our analysis suggests any time delays should be analyzed carefully. Much of the deepwater GoM is marginal under a one and two year field start-up delay, without consideration for higher costs. Further uncertainty will hinder incentives to develop the deepwater.

The impacts of Macondo and current delays lowers estimates for full-cycle returns below the hurdle rates considered herein for 10 of the 25 probable developments in our Base Case. This number increases to 17 of the 25 probable field developments under a two year logistical delay. While many of the 17 fields will continue through to development with lower returns than initially planned, approximately two-thirds of known probable discoveries in the Deepwater GoM fall below our economic thresholds. The expected impact will likely be somewhere between our Base Case and 2-year delay case, but the future of the GoM is currently very uncertain. Deeper, more challenging plays, which are more costly and provide much of the expected future growth, are disproportionately affected due to already marginal returns.

6. Appendix

Permitting Background

After the lifting of the moratorium, BOEMRE (formerly MMS) clearly stated its permitting approval rates would not return to those prior to the Macondo incident. This promised slowdown on turning around applications for permit to drill (APD) has become one of the main concerns of the offshore industry. Longer waiting periods to drill new wells along with the increased costs per well suggested by BOEMRE have incited a great deal of uncertainty in the future production of the Gulf of Mexico.

Permitting trends for deepwater wells prior to April 2010 looked promising. The average approval time in January 2010 was one-sixth of the rate back in January 2009. The overall BOEMRE turnover in years prior to May 2010 reached about 10 days per permit, at an average of 20 to 30 permits per month. After the moratorium was enacted, the BOEMRE timeframe increased to a rate of 35 days per permit. Due to anticipation of a continued slower rate of approval, Wood Mackenzie estimates drilling activity to only return to pre-Macondo levels in no earlier than late-2011.

Not only have permitting trends showed a bleaker future, but the requirements to attain approval of an APD have also changed in recent months. The passage of regulation by BOEMRE and the enactment of rules by the Department of the Interior has expanded the scope of required activity prior to an application. The bullets below first display the general prerequisites for approval of an APD. The second set reveal the additional conditions post-Macondo which operators must meet prior to their APD approval.

General Requirements for APD Approval

- Completed APD form
- Approved Exploration Plan or Development Operations Coordination Document (DOCD)
- Offshore Financial Responsibility demonstration
- Compliance with 30 CFR 250
    - NTL – 2009 P03 (OSRP [regional] Worst Case Discharge)

Additional Requirements Post-Macondo

- NTL – 05 (Safety, Professional Engineer certification)
- NTL – 06 (Environmental, Worst-Case Discharge)
- Drilling Safety Rule (API Practices, BOP, deadman system, training)
- Workplace Safety Rule (SEMS)
- 30 CFR 250 added components
    - Casing and cementing (best practice, detail description)
    - BOP (testing, equipment descriptions, third-party verification)
    - Drilling fluid (safe practices, details)
    - Directional plot of directional wells
    - Description of qualifications required of an independent third party
    - Approval for displacing cement to facilitate abandonment

The additional paperwork could suggest longer periods to verify accuracy, and along with the slower approval rates evaluated above means development projects could have their start dates significantly pushed back. Both of these conclusions contribute to our delay assumptions for this API study.

Variances from our forecast

We did not consider any costs increases outside of the estimates provided by BOEMRE in an effort to isolate the issue of timing. In reality, there are additional costs increases expected that are not factored into this analysis.

Reasonable certainty in permitting is needed for the long lead times and development times of large-scale deepwater GoM projects. While we have considered a one and two year delay, it will likely take less of a delay in the permitting process to cause field start-up to shift back one to two years.

Our Base Case model represents Wood Mackenzie's post-Macondo view of field development. This is determined by analyses of field-specific cases incorporating delay (if any) in the near-term as impacted by the moratorium, and any expected potential delay in the long-term as understood from either input from the operator and/or our best estimate of development timeframes. Wood Mackenzie currently uses pre-Macondo view of cost factors with no changes associated with materials, services, and technology.

The study includes development prospects only in the deepwater, which is defined at Wood Mackenzie as water depths of 400 metres (1,312 feet) or more.

This methodology assumes companies will cease investment if returns fall below our accepted level under our pricing assumptions. Projects in which no spend has occurred are more likely to be effected, while projects with sunk costs make a point forward decision more attractive than a full-cycle.

Company strategies also vary and companies might require a higher or lower IRR than 15% for investment decisions. Companies can also be motivated to continue drilling without sufficient economics for reasons not considered such as: drilling to hold leases, a portfolio view of drilling, better long-term well recovery and production rate expectations, scopes for future satellite tie-ins, as well as higher future price assumptions.

The projected amount of investment loss drops considerably through the 2015-2020 timeframe. This is a function of Wood Mackenzie modelling probable developments. We do not account for technical or 3P reserves, which will require further investment in the later years of our forecast.

This analysis does not consider yet-to-find (YTF) developments, but does indicate they will be challenged in a post-Macondo environment.

A probable development is defined by Wood Mackenzie as a field that has yet to start development but is included in the partners' long term plans and we expect to get developed under our Base Case assumptions.

For purposes of this analysis, we have assumed a 35% corporate tax rate.

The impact for oil investment and production could be greater if the long-term outlook for oil prices falls below those considered herein.

Wood Mackenzie utilized its WTI crude oil planning price assumptions of $87.40 / barrel in 2011, $83.50 in 2012, $81.18 in 2013, $82.81 in 2014, and $84.46 in 2015 inflating thereafter.

Wood Mackenzie's Henry Hub natural gas planning price assumptions are $5.20/mcf in 2011, $5.43/mcf in 2012, $6.14/mcf in 2013, $6.54/mcf in 2014, and $6.85 in 2015 inflating thereafter.