A Comparison of Fiscal Regimes
Offshore Natural Gas in Israel

SPECIAL REPORT™
A COMPARISON OF FISCAL REGIMES

IHS CERA has been requested by Noble Energy and its coventurers to consider how the current fiscal regime in Israel compares with other fiscal regimes for natural gas developments and to discuss the impacts and advisability of retroactive changes to a fiscal regime.

KEY FINDINGS

The mean government take (defined as the undiscounted revenues that accrue to the government as a percentage of the total undiscounted net revenues of a project) calculated for a peer group of deepwater offshore opportunities and across a range of natural gas prices and field sizes is 60 percent. This compares with a range of 38–50 percent for Israel. More specifically, when compared with the government take in the United Kingdom and United States, Israel’s government share averages 42 percent versus 56 percent for the United Kingdom and 52 percent for the United States. On the surface these figures suggest that Israel is more attractive than its peers under the current terms. But government take is a misleading measure as it is not among the metrics that oil and gas investors use to make investment decisions.

A company is more likely to invest in a country with a fiscal regime that provides a 90 percent government take while allowing a rate of return of 20 percent than a fiscal regime that provides a 50 percent government take while permitting only a 10 percent rate of return. Government take does not provide any measure of the attractiveness of a fiscal regime. Some analysts calculate the percentage of the gross revenues of a project that accrue to the government (that we shall define as gross government take). By this measure, Israel’s gross government take averages 30 percent versus 29 percent for the United Kingdom and 37 percent for the United States. However this represents an even less useful measure of the attractiveness of a fiscal regime because it excludes any impact of the costs, complexity of extraction and realized prices resulting from both differences in location (basis differentials) or market structure. There is more scope for government take in a setting of readily accessible reserves in a low unit cost development environment—it should not be surprising that Iraq is able to demand a greater government share than Alberta can extract from oil sands development.

The more appropriate measures of the attractiveness of a fiscal regime are

- the rate of return permitted to the investor on development
- the profit-to-investment ratio of development (a measure of the capital efficiency and therefore a guide to where a company should direct its capital)
- the exploration cover ratio (a guide to whether it is worth investing in trying to discover hydrocarbons in the first place)

The figures for all three indicators suggest that Israel’s current regime is competitive with other similar regimes—discovered reserves are likely to be developed and exploration prospects to be drilled under current terms. However, Israel is not the most attractive destination for investment—it lies in the bottom half of the peer group.
Furthermore, a change in the fiscal terms, particularly a retroactive change to the terms for existing licenses, would damage the prospects for investment in Israel in two ways:

- It could slow and even halt investment in developing discovered reserves and would likely lead to a moratorium on further exploration.

- It would undermine confidence in the stability of the fiscal regime, further reducing the economic threshold for investment below what might be expected based on the actual revised terms.

Retroactive changes in fiscal terms (i.e., covering existing licenses) will reduce the attractiveness of investment in Israel just at a time that perceptions of its prospectivity seem to have increased. Israel is already viewed as a risky investment destination. In an overall political risk ranking of 125 countries, Israel ranks 113, alongside countries including Sudan, Bolivia, Myanmar, and Sierra Leone. Retroactive fiscal changes will not enhance this standing.

It would be a shame to damage the realization of value from Israel’s potential natural gas endowment rather than to learn from the experience of other states that have demonstrated the adverse results that can arise from such actions. The effects of a retroactive change in the fiscal regime would be long lasting. It takes many years to develop a reputation for stability but only a few months to destroy it.

In this report we shall explain where Israel ranks, both in terms of the risk profile of investment and in terms of the metrics that investors apply in deciding where to direct their discretionary spending. We shall also explain the likely consequences of retrospective changes in fiscal terms.

**THE FISCAL BARGAIN AND GOVERNMENT TAKE**

When comparing fiscal regimes most analyses focus on the level of “state take” as a tool for ranking the relative attractiveness. We believe this is an oversimplification, particularly when the calculation is of the percentage of the gross project revenues that accrue to the state as this ignores even the effect of differences in costs of development and production. Ranking on state take, even when calculated as a percentage of net project revenues, is a crude proxy for what really influences investment decisions—the value creation resulting from the deployment of investors’ capital.

More useful, detailed fiscal analyses can be obtained by applying different fiscal regimes to a single example model field and comparing the resulting development economics of the investor under standardized oil and gas price assumptions but with adjustments for the basis differentials caused by distances to liquidly traded markets. However, this approach still oversimplifies the situation by assuming a world devoid of varying geographies, climates, topographies, and reservoir conditions, not to mention market conditions (including whether markets are regulated or trade on a spot basis) and, potentially, local economic effects.

However, the Sheshinski Committee is considering whether it is appropriate to change the terms of the “fiscal bargain”—this bargain is a trade of the investor’s capital, technology, and know-how in return for a share of the profits of development—to reflect the greater
prospectivity that has been revealed by recent exploration successes. This so-called “obsolescing bargain” is regularly tested in the oil and gas industry as host governments reappraise, with the benefit of hindsight, the risks that were taken by the investor.

In general, there appear to be three drivers for such a reappraisal of the fiscal bargain:

- **Political Ideology**: A new government adopts the view that its predecessor was too generous in the terms it offered for granting mineral rights. This populist message is exemplified by Venezuela, Bolivia, and Ecuador among others.

- **“Oil Price Windfalls”**: Changes in oil and gas prices cause investments to deliver higher returns than may have been anticipated causing governments to attempt to capture their fair share of this uncovenanted windfall. When prices fall, governments rarely adjust terms to protect companies from returns that are lower than anticipated. This reaction to price changes may explain recent initiatives by Alaska, Alberta, Russia, and Nigeria (discussed below) among others in the past few years.

- **“Volumetric Windfalls”**: The terms offered to attract investment into exploring a new basin turn out to deliver high returns once the exploration risk has been removed. This driver describes the evolution of terms in many OPEC countries during the 1950s and 1960s, before Price Windfalls took over as the main driver of change in the 1970s.

In the case of ideologically driven changes, these are almost always applied retroactively with an immediate negative impact on investment levels and in many cases, prolonged litigation/arbitration proceedings.

Price windfall driven amendments to fiscal terms also tend to be applied retroactively, but not in all circumstances.

The most prominent examples of altering the fiscal bargain in the face of volumetric windfalls date back to the opening of the most prolific basins during the middle of the last century in the countries that now account for the majority of global oil reserves. By contrast, Brazil’s revisions to the regime for subsalt developments are not being applied retroactively. But on a more local and recent level, the lease terms under which investors can acquire mineral rights to shale gas plays in the United States illustrate a change driven by changes in perceived prospectivity. However, in this instance, the changes apply only to new leases and there is no retroactivity.

Anecdotally, retroactive revisions to the fiscal terms resulting from an oil price “windfall” appear to damage investor sentiment less than revisions arising as a result of changes in perceived prospectivity or from political ideology.

Many governments resist the temptation to alter the terms of the “fiscal bargain”—identifying that long term stability has a value in terms of the investment that it will encourage. Those that yield to the temptation are surprised by the extent to which activity levels are reduced by changes in their fiscal regimes. Examples that seem to have been driven by rising oil prices include:
• Alberta’s *Our Fair Share* review of royalties in the province in 2007 caused a reduction in shale gas drilling—meanwhile industry attitudes to drilling in immediately adjacent tracts of British Columbia remained positive.

• “Alaska’s Clear and Equitable Share” (ACES) legislation in 2007 caused reductions in capital expenditure not seen since oil prices were below $20 per barrel.

• Russia’s increases in the export tax and the Mineral Resources Extraction Tax led to a mid-decade slowdown in production growth and even outright decline. The Russian government is in the midst of a reexamination of its fiscal system to encourage future investment.

• Nigeria’s current debate about a “Petroleum Industry Bill” is already leading to a reduction in capital investment in both exploration and development.

An interesting example of the impact of a change that was intended to be broadly neutral or even beneficial to the industry is provided by the United Kingdom. Changes in the Petroleum Revenue Tax in the United Kingdom during the early part of the 1990s affected industry development. Even a revenue-neutral measure caused a 20 percent decline in exploration and appraisal activity.

Appendix 1 provides more detail for each case. The story was the same in each case (with the exception of the United Kingdom example—where the tax change was actually intended to benefit the industry.) Prices increased and governments pointed to the need to increase their state take as it seemed to be less than their chosen peer group of countries. In the aftermath of the changes they question why they are not receiving what they consider to be appropriate levels of investment once the taxes and/or royalties rise.

**APPROACH**

To help governments understand these dynamics, IHS CERA has developed an alternative framework for considering fiscal regimes in host countries—a framework based on the return to the investor rather than the level of government take.

First, we consider which countries’ natural gas resources face technical, economic, commercial, and political challenges similar to Israel’s. The filtering process is described below.

Next, we select conceptual development plans for sample gas fields that are appropriate to each environment—in a range of sizes and at a range of product prices. For Israel we have modeled conceptual developments using an analogue for the Tamar field in 1,676 meters of water. These analyses are generated using the data and tools of our parent company, IHS Inc., and allow a true “apples-to-apples” comparison of what is left to the concessionaire. The estimates of development capital for field sizes used in our analysis range from $0.25 to $1.10 per thousand cubic feet of gas (or $1.50 to $6.50 per barrel of oil equivalent).*

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*6,000 cubic feet of natural gas is equivalent to one barrel of oil in energy terms.
We determine what share of the barrel (or barrel equivalent) is left to the concessionaire in each jurisdiction. State take competes with capital and operating costs and the time value of money for the remainder. Unless the share of the barrel received by the investor compensates for the risks of exploration, development, production, and eventual decommissioning, the oil and gas resources will not be developed.

In previous submissions to the government of Israel and, indeed, in analysis provided by IHS Inc. in 2002, the government take (including corporate income taxes) in Israel is 45.6 percent—apparently more attractive than an average for “all fiscal regimes” of 67 percent, based on IHS CERA’s own analysis of a wide range of fiscal regimes performed for its 2005 Special Report *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures*. This higher average level of fiscal take than Israel’s is explained by the large number of countries (particularly oil producers) holding reserves that are low cost to develop. The pretax profitability of activities in such countries (i.e., before any taxes or royalties or other state take) leaves more room for the government to take a higher share of the rent than in a higher-cost development environment or where price realizations for produced hydrocarbons are low.

**CHOOSING THE RIGHT PEER GROUP**

To compare Israel’s fiscal regime with its competitors and peers, IHS CERA selected a peer group consisting of a more limited set of basins—typically deepwater offshore environments in OECD member countries (where hydrocarbon rents were a small enough component of the gross domestic product (GDP) that the countries had an incentive to try and avoid “Dutch Disease” or other forms of resource curse). The chosen peer group reflects our best estimate of the hydrocarbon provinces that are competing with Israel for investment.

In this instance we filtered the more than 125 countries for which we maintain detailed descriptions of the fiscal, regulatory, and operating environment to come to a manageable peer group. Filtering for whether they have significant offshore gas resources reduces the sample to 92. We then identified countries that were not likely to see hydrocarbon resources as a primary component of GDP—filtering for OECD membership, which reduced the sample to 18 countries. Excluding those with remaining reserves of less than 1 trillion cubic feet (Tcf) reduced the sample set to 12 countries. In order of their remaining reserves, these are:

- United States
- Australia
- Norway
- United Kingdom
- Canada
- Netherlands
- Italy
- Mexico
- Ireland
- Denmark
- New Zealand
- Germany
Of these countries, Germany, Denmark, and the Netherlands have no deepwater activity. Mexico operates under a PEMEX monopoly (state-owned, with oil companies able to act as service companies—a completely different model). We therefore replaced them with three of Israel’s neighbors that do have deeper-water potential for natural gas—Egypt, Libya, and Tunisia. Finally, we added Ghana as an example of a newly emerging producer that faces the challenge of developing an export market.

With one or two exceptions, the members of the peer group of countries are all established producing provinces. It might have been more appropriate to compare Israel only to those countries that have not yet established deepwater offshore hydrocarbon reserves. However such a comparison risked appearing overly hypothetical and we preferred to consider regimes that have been tested by a track record of actual investment history.

A feature of some of these producing basins is the lack of export infrastructure, which will either delay incremental developments or result in lower natural gas prices once the domestic market is saturated. This can result in long lead times between discovery and development; and long lead times in turn limit the potential for fiscal regimes that do not recognize the time value of money—and the damage that this does to project economics.

Taking into account these criteria, IHS CERA’s selected peer group (illustrated in red on Figure 1) includes the following regimes:

- Australia
- Canada
- Egypt
- Ghana
- Ireland
- Italy
- Libya
- New Zealand
- Norway
- Tunisia
- United Kingdom
- United States

**PLACING ISRAEL IN ITS PEER GROUP**

IHS CERA has ranked the fiscal regimes by assessing the full-cycle exploration and development economics of a range of field sizes and at a range of natural gas prices. The example developments have been analyzed by applying the costs of developing a field in each operating environment to a standard production profile for each field size. In our analysis, we chose

- gas fields of 1, 5, and 10 Tcf
- gas prices in each end market based either on domestic prices or on export markets, where such exist
We applied costs of transportation (including liquefaction, shipping, and regasification if liquefied natural gas (LNG) is the chosen development pathway) to the nearest markets in which these prices could be accessed.

The economics were run in dollar-of-the-day terms to avoid the need to make assumptions about escalation rates for oil and gas prices and costs. We used costs based on fourth quarter 2009 market conditions for each hydrocarbon province. The relative ranking of each province would not change by using nominal economics, even though the absolute level of returns would be greater. Furthermore we have assumed fiscal stability in all markets despite Israel’s possibly having undermined the perception of fiscal stability by convening this Committee (as has been the case for several other members of the peer group). We have made no attempt to predict the outcome of the review for fiscal terms that are not yet in effect.

Figures 2–4 rank the attractiveness of activity under the existing regime for Israel versus the current regimes of the peer group members.

Based on ranking by government take, Israel’s fiscal regime for current and future discoveries appears to be the third most attractive in the peer group. In other words only 2 governments appear to take a smaller share of the rent. But as we have explained, this oversimplifies the question and may, in fact, be misleading. Companies do not invest on the basis of the government’s notional share of the returns; they focus on the investor’s actual economic returns on their investment and value creation.
Figure 2
Government Take

Canada
Ireland
Italy
New Zealand
United States
Ghana
United Kingdom
Tunisia
Australia
Egypt
Norway
Libya

Source: IHS CERA
00711-2

Figure 3
Full Cycle Rate of Return

Ireland
Australia
Italy
Egypt
New Zealand
Ghana
United States
United Kingdom
Tunisia
Canada
Norway
Libya

Range of Uncertainty

Source: IHS CERA
00711-3
Figures 3 and 4 show the rankings based on real rate of return and the profit-to-investment ratio (calculated using a 10 percent real discount rate). The higher up the ranking, the more attractive it is for an investor to participate. The range of uncertainty refers to the combination of the probabilistic distribution of likely costs that may actually be incurred in a development and the economics of both domestic and export market gas prices.

**INTRODUCING EXPLORATION RISK INTO THE EQUATION**

So far this analysis covers only the development of hydrocarbon resources—it excludes the risks and costs of abortive exploration. The other important factor is whether the value created through successful exploration is sufficient to support the costs and risks of exploration. Companies will typically not invest in exploration unless they expect to create significant value. One of the most common ways of measuring the value expected to be created through an exploration program is to calculate the expected monetary value (EMV) of the exploration prospects covered by the program. In its simplest form this can be calculated as

$$\text{EMV} = \text{Value}_{\text{Success}} \times \text{Probability}_{\text{Success}} - \text{Cost}_{\text{Exploration}} \times \text{Probability}_{\text{Failure}}$$

It is important to stress that the aggregate shows results for a portfolio rather than assigning value to any individual prospect (where the outcome is often binary—either zero or high value). Furthermore, one can also calculate an “exploration cover ratio”—the result of dividing Value$_{\text{Success}}$ by Cost$_{\text{Exploration}}$. When exploring in a frontier basin, it is not uncommon to seek exploration cover ratios of ten and more. Figure 5 ranks Israel’s peer group by their exploration cover ratios.
By the measures shown above, Israel’s current fiscal regime ranks among the middle of its peer group in terms of development metrics (rate of return and profit-to-investment ratio and exploration cover ratio).

Our assessment is that the current domestic natural gas price for Israel is only a little above the equivalent netback price on production into an export project (whether pipeline or LNG). In either case IHS CERA’s market review indicates a natural gas price estimate in the region of $4.00 per MMBtu. Any reduction in the natural gas price will move Israel down the rankings—as would arise if the market became oversupplied because of a lack of access to land for building facilities or lack of regulatory approvals for exports of gas.

DEEPWATER INCENTIVES FOR INVESTMENT

Israel’s emergence as a deepwater hydrocarbon resource holder poses challenges for developing a fiscal regime that is resilient to the differing challenges that deepwater activity poses. This is not a unique problem. A number of countries address the greater costs and complexity of deepwater exploration and development by implementing terms for deepwater activity that are less onerous than shallow water terms. These include:

- Angola
- Australia
- Bangladesh
- Jamaica
- Morocco
- Myanmar
The benefits of the improvements in terms are intended to compensate investors for the additional costs and risks that deepwater activity imposes on returns. Figure 6 shows the improvement in rate of return that arises from calculating the outcome of deepwater terms.
compared to those applying to shallow water for the same representative development scheme. The apparent exception of Australia arises from the imposition of Resource Rent Tax (RRT) on federally administered offshore areas (typically deeper water) versus state administered areas (typically shallow water).

Typical incentives include

- lower royalties (or no royalty) for gas,
- higher cost recovery ceilings or depreciation uplifts,
- higher contractor profit shares in PSAs,
- tax holidays
- depletion allowances.

Most countries that seek to encourage deepwater investment combine more than one incentive to attract investment especially in frontier or high cost areas. Increasing cost recovery ceilings to reduce cost exposure and the reduction or exemption from royalties and “super profits” taxes for natural gas can significantly increase the attractiveness of deepwater investment.

An analogous situation to deepwater incentives is presented by the development of natural gas from tight reservoirs in the United States. Acceleration of the innovation to produce such natural gas, culminating in the “Shale Gale”—the exponential increase in production of natural gas from shale formations—is often attributed to the Section 29 credits that provided tax incentives to producers who developed natural gas in low permeability reservoirs.

The exemption of the first 50 million barrels of oil equivalent from royalties in the US Gulf of Mexico is often credited with encouraging the rapid development of the province. But ironically, it was the US government’s failed attempt to retroactively revoke this incentive that has done most to damage its reputation for stability in recent years. This important factor—what we refer to as the dynamic aspects of fiscal regimes—is an important consideration when governments consider altering the terms under which they grant mineral rights.

**DYNAMIC ASPECTS OF FISCAL REGIMES**

In the benchmarking above, we have only considered fiscal terms in a static equilibrium. However, investing companies also consider the likelihood of changes to the outlook—including oil and gas prices, cost escalations, and the fiscal regime under which they operate. In the example cited above on US deepwater royalty incentives, Anadarko Petroleum successfully challenged the changes in court. To increase the pressure on companies, legislators proposed laws that would ban companies from applying for future federal oil and gas leases if they refused to accept the retroactive changes “voluntarily”. This is an example of actions guaranteed to increase the risk of future adverse changes in a fiscal and regulatory environment.
It is difficult to quantify the impacts of expectations of any future changes. But we can offer a qualitative assessment of the extent to which fears of future fiscal changes can affect the relative attractiveness of different hydrocarbon provinces.

Over the past several years five self-evident factors have conspired to reduce the attractiveness of investment in the Israeli deepwater offshore:

- the worldwide economic crisis and the relatively slow recovery now under way—with its resulting impact on gas demand
- the excess deliverable capacity of LNG production, which had been slated for US markets until the impact of the North American “shale gale” dramatically reduced the likely level of such imports and lowered the price outlook for markets in which this excess LNG will be placed
- the significant escalation of capital and operating costs caused by tight supply chain conditions, particularly for deepwater drilling rigs and for the high-specification steel tubular consumed in drilling such wells
- the likely saturation of the current and projected domestic market with the Tamar and Dalit discoveries
- the reexamination of Israeli fiscal terms being considered by this Committee

These first three factors particularly affect the attractiveness of potential export projects in Israel. They have made operators elsewhere around the world much more cautious and introspective about the types of large-scale investments required to commercialize LNG-scale natural gas resources.

The last two factors may be more specific to Israel. The fourth factor will impact the attractiveness of investment unless there is clarity about the regulatory and political framework and about the path to overcome the significant technical challenges posed by gas exports from Israel. The fifth factor applies equally to domestic and export projects. It creates the perception of continued but potentially degrading stability of the Israeli fiscal regime.

IHS analyzes countries in terms of their overall political risk, which includes political, socioeconomic, and commercial attributes. This is performed through a systematic scoring of the various dimensions of political risk and provides a quantification of the various qualitative measures that contribute to the overall scores.*

Figure 7 shows the relative overall ranking of the peer group countries and Israel’s immediate neighbors in the PEPS coverage. Israel ranks 113, alongside countries including Sudan, Bolivia, Myanmar, and Sierra Leone. In other words, Israel ranks poorly—as it has for some time. The 2002 update of PEPS records the following observations:

*Petroleum Economics and Policy Solutions (PEPS)—an IHS product that is regularly updated and widely used by companies active in the global oil and gas business. PEPS provides statistical data and analysis concerning some 125 hydrocarbon provinces, including political risk assessment and fiscal terms.
**Opposition to Foreign Investment**

There is no formal government opposition to foreign investment in Israel—indeed, quite the opposite is true. However, three factors serve as significant external constraints on foreign investment. First, the announcement from Israel’s National Infrastructure Ministry in July 2000 that it was suspending new licenses and permits to consider what would be tougher terms has had a chilling effect on investors, who were quick to announce they would reconsider further investment in Israel if royalty rates were significantly altered … that threat has been reiterated as legislation slowly makes its way through government. Second, the threat of a Middle East war involving Israel is omnipresent …, and companies cannot help but account for this in their investment plans. Third, the omnipresent threat of internal violence … is one that cannot be ignored, even during times of relative peace in the nation…

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Source: IHS CERA,
00711-6
...Threat of Adverse Contract/Fiscal Changes

Given Israel’s standing as a nation devoted to the rule of law (and thus protection of property rights), it is almost paradoxical to warn here about the threat of adverse contract/fiscal changes. However, in July 2000 Israel’s National Infrastructure Ministry suspended the issuance of offshore licenses and permits for new ventures to evaluate its current policy. Press reports indicate that the government plans to raise royalty rates from the current 12.5 percent to as high as 50 percent. The Ministry has pointed out that any changes would not be retroactive—and thus would not apply to currently approved projects—but at a time when so many nations are revising their fiscal terms to make them more competitive, the likelihood that Israel is even considering less competitive terms represents a significant threat of adverse fiscal changes against future expectations. Investors have been quick to point this out…”

In 2002 only 5 of the 119 countries that IHS then covered were considered less attractive than Israel from an overall political risk perspective. The 2009 rankings broadly confirmed these findings.

If the Committee were to recommend materially altering the fiscal terms, it would cement the perception of lessening fiscal stability and likely impede investment in Israel’s exploration and development opportunities in the coming years.

CONSEQUENCES OF CHANGING FISCAL REGIMES

Earlier we discussed the “obsolescing bargain” that characterizes hydrocarbon-producing provinces. Governments may be unable to resist the temptation to capture more of the economic rent after the risks have been taken. This generally results in more revenues in the short term but at the expense of longer-term investment activity and the fiscal revenues that could be derived therefrom.

There are three key points along the spectrum of fiscal terms that the Committee might adopt following its deliberations.

Terms to Encourage Further Exploration

The fiscal terms may be set so that the value of any likely discovery (the net present value calculated at an appropriate cost of capital for an Israeli company investing) is sufficient to compensate for the costs of dry exploration wells. In this situation the returns on successful discoveries will be higher than the average shareholder return that such investors reasonably demand (e.g., when compared with the returns earned by other industries). These extra project-level returns are necessary to compensate for the abortive exploration costs.

- Provided that such terms apply only to new licenses, there is limited downside for Israel in positioning its fiscal take at this boundary point. However, IHS CERA’s analysis indicates that there are several more attractive locations in which to explore for natural gas in the immediate neighborhood of Israel.
• There would still be a risk that Israel would not attract sufficient capital investment to properly explore its potential resources. Furthermore if companies had invested in the leases, such a retroactive change would disproportionately damage Israel’s reputation unless provision were made to refund an appropriate share of the sums invested to compensate for the changed fiscal terms.

Terms That Permit Development of What Has Already Been Discovered

If the Israeli government concludes that there is no further exploration prospectivity, then it might choose to tighten fiscal terms to a level that captures any excess rents above the share necessary to provide a rate of return equivalent to, or only slightly more than, the investor’s cost of capital. In mature provinces this would not sacrifice future revenues (unless it is subsequently found that the assumption about lack of exploration prospectivity is wrong).

• In practice, governments are prone to underestimating the remaining potential of a province as new geological concepts that were not considered at the time are subsequently tested and confirmed. This has been a feature of the North Sea, the Gulf of Mexico, and many other hydrocarbon provinces.

• Damage is done whether or not the state take changes. In the first case described above, there are no retroactive changes to the terms applying to existing discoveries. In the second case the retroactivity would apply to existing discoveries. With the risk already taken and, in many cases, substantial capital already committed, the damage to Israel’s reputation and the risks going forward would become substantial.

Terms that Do Not Permit Even the Development of Existing Discoveries

If the Israeli government concludes that even existing discoveries are not needed to meet its domestic energy needs, then there is limited cost to tightening the fiscal regime to capture the maximum share of the revenues from existing producing fields.

If the market subsequently requires further development, then it may appear that the terms can simply be loosened to encourage investment (provided that investors can be convinced of their future stability). In practice, investors would require fiscal indemnification before they would consider investing in a sector that had previously imposed such draconian terms on investment.

Resisting the Temptation to Make Retroactive Changes

It can appear to be politically expedient to retroactively alter the fiscal terms governing oil and gas investment. The very nature of the business creates a timing difference between the investment of risk capital and the returns required to repay not just development costs but the abortive exploration costs as well—individual project returns are nearly always higher than overall corporate returns. However, this strategy is almost never a good idea unless the investment prospects are so attractive that investors will still take the risk—such as was the case among major oil producers including Saudi Arabia, Venezuela, Iran, Iraq, Kuwait, and others, beginning in the 1950s. Israel does not fall into this peer group—holding such huge
resource potential that companies will feel that they cannot afford to ignore the investment opportunities.

It is worth repeating the conclusions regarding retroactive changes to the fiscal regimes contained in the report IHS submitted to the Israeli government in 2002:

“Various levels of retroactivity could be considered:

− Apply to all existing licences and production leases.
− Apply to all existing licences only.
− Apply to existing licences following completion of the committed work programme.
− Apply to new entrants to existing licences and production leases.
− Apply to new licences and subsequent production leases only.

“Preliminary permits have been excluded from the permutations above on the basis that the level of expenditure connected with the permit is much less than that likely to be committed to under a licence or lease. However, similar arguments apply.

“The general point needs to be made that applying a new, more severe tax system to existing investments will lead the industry to discount the future stability of any terms that are applied. An industry at the early stage of development of the Israeli industry should focus on building trust and stability, which has considerable value to investors, and maximising future income by encouraging more activity.

“Imposing new terms on existing licences and leases, where risky investments have been made on the basis of a certain financial outcome if exploration is successful, is likely to be met by considerable resistance, and it would be advisable to undertake analysis of the impact of the new terms on existing projects before making such a decision. In particular, the effects of the changes on the participants’ loan covenants, debt cover ratios, and ability to service debt in general might be affected.

“Restricting the application of the new terms to new entrants to existing licences and leases appears to be a fairer method. However, the likely result is a split partnership facing different economic drivers. A significant change in the fiscal terms applying only to new investors in a potential development or exploration programme may well lead eventually to a decision-making stalemate between the two groups. In high-risk, high-cost areas, it is important that the investors are aligned with each other. Investors will not wish to invest risk-money in ventures that may become bogged down in disputed decision making. There would also be an impact on existing participants’ perceived asset values, since the higher value seen by an existing participant could not be realised through an asset sale, and encouragement would be given to complex asset deals wrapped up in corporate shells designed to preserve eligibility for existing fiscal terms.
“If an element of retroactivity is to be considered, it should be restricted to licences where the committed work programme has been completed. To impose new fiscal terms on undrilled commitment wells would be extremely unpopular. Following completion of the work programme the participant would have the option to relinquish the licence and the MNI would be able to relicense it. However, imposing new terms following completion of a work programme on a licence where a potentially commercial discovery has been made would face similar problems to imposing the new terms on a production lease.

“The least objectionable method of maximising the capture of old licences under the new terms would be to apply the terms only to the product of new wells drilled on the licence following completion of existing work programmes. However, for a country with few significant discoveries and a need to attract, rather than ration, potential investors, any sort of retroactive application of new fiscal terms should be avoided unless the short-term tax revenue gain is so badly needed that it is felt to outweigh the longer-term revenue penalty caused by the discouragement to activity.

“To summarise, our general recommendation on retroactive application of fiscal terms is that we strongly advise against doing so. Retroactive application of the Petroleum Tax will deter investors and increase the perceived risk of future adverse retroactive changes which will take a very long time to cancel out.”*

IHS CERA’s opinion is the same as our predecessors’ at IHS (more than two years before CERA was acquired by IHS). A number of resource holding countries recognize this also. They address the concern by “grandfathering” (i.e., not changing) the terms applicable to existing licensees.

Grandfathering of terms represents the least damaging approach to fiscal changes because it respects the sanctity of the “fiscal bargain” between resource holder and investor—sometimes the stability is incorporated into the lease agreement or other contract granting the mineral rights. It allows a government to capture the value of the improved prospectivity that may not have been recognized when the hydrocarbon province was opening up but without undermining the original bargain that opened it up in the first place.

By contrast, retroactive changes in fiscal terms (i.e., covering existing licenses and leases) will damage the attractiveness of investment in Israel just at a time that perceptions of its prospectivity seem to have increased. This is not the first time that the government of Israel has contemplated changing the fiscal regime in the face of new discoveries. This time around, it would be a shame to damage the realization of value from Israel’s potential natural gas endowment rather than to learn from the experience of other states that have demonstrated the adverse results that can arise from such actions.

APPENDIX 1: OTHER RETROACTIVE FISCAL CHANGE EXAMPLES

PROVINCE OF ALBERTA, CANADA, 2007

In 2007, with oil prices rising toward unprecedented levels, the new administration of Premier Ed Stelmach ordered a review of royalties, appointing a committee of respected business leaders that included former oil industry executives. Their report *Our Fair Share* concluded that Alberta took a smaller share of the rents than many of its chosen comparator provinces. The suggested changes were enacted—with a deleterious impact on investment levels. The timing was especially bad because the new royalties were enacted in 2009 as the growth in shale gas in North America reduced natural gas prices.

Comparison of industry appetites to invest in shale gas plays in British Columbia, which acted to attract investment, contrasted with Alberta’s more investment unfriendly approach, provides a graphic illustration of the wisdom of retroactive changes in the fiscal regime.

Subsequently the Government of Alberta ordered a new review to determine how it could restore investment levels. It announced reductions in royalty levels to their pre-*Our Fair Share* levels beginning January 1, 2011.

ALASKA, 2007

Presented with the opportunity created by record oil prices, the administration of Governor Sarah Palin determined that Alaska was not receiving as much benefit from increased oil prices as it deserved and implemented a program called “Alaska’s Clear and Equitable Share” (ACES). The main thrust of the new tax system was to provide more reliable revenues and a larger share of the rent to the state.

Despite warnings of the unsustainability of the oil prices and the risks to investment through fiscal instability, the legislation was passed with very little opposition. Some legislators still consider it to have been a success, but activity has declined to levels not seen since oil prices were below $20 per barrel. There have been some calls for a review of the fiscal regime, and it continues to be an issue in the gubernatorial elections scheduled for November 2010.

RUSSIAN FEDERATION, 2005

An increasing tax burden was among the primary factors in the sharp downturn in Russian oil production growth rates starting in 2005. After a surge in Russian crude output over 1999–2004 boosted the country’s oil production by over 50 percent, annual production growth has been little more than 2 percent at most since 2005 and turned negative in 2008 before recovering in 2009.

Since 2002, both of the principle taxes on crude oil, the export tax and the Mineral Resources Extraction Tax (MRET), have been based on a sliding scale mechanism tied to European prices of Urals Blend. This ensures a progressively larger tax take with each jump in the world oil price. Simultaneously the government increased the MRET base rate on several occasions prior to the 2005 drop in Russian oil production growth rates—from 340 rubles
per ton in 2003 to 347 rubles per ton in 2004 and 419 rubles per ton in 2005. Thus even though the rise in world oil prices in the first half of the decade led to a tripling of the Russian oil companies’ oil sales revenue, the chief oil industry taxes grew even faster than revenue, particularly after mid-2004, eroding the positive financial effect from rising export prices. In absolute terms the export tax and MRET had grown by more than 500 percent by the end of 2005 compared with January 2003.

Following the outright decline in Russian oil output in 2008, the Russian government revisited the fiscal regime in an effort to restart upstream investment activity. The overwhelming focus of fiscal reform so far has been on creation of additional incentives for greenfield developments in new hydrocarbon provinces; i.e., selective exemptions from MRET levies and (in the case of East Siberia) the export duty. Increasing oil output from new fields benefitting from the new tax breaks (particularly Rosneft’s Vankor field in East Siberia) has been critical to offsetting the ongoing decline from Russia’s mature West Siberian Basin and reversing the overall Russian oil production decline in 2008. However, longer-term, sustainable production growth is still contingent on more systematic fiscal reform, including more relief for companies developing mature fields and the move from revenue-based to profit-based taxation.

NIGERIA, 2010

Perhaps driven by record oil prices when it was first conceived, the Petroleum Industry Bill (PIB) has been debated for more than two years between the executive branch, the legislature and the oil industry in Nigeria. At issue is whether developments of existing discoveries will be economically viable under the proposed new terms and whether exploration investment will be maintained to support future production and reserves growth.

At the time of writing this report, it appears that political considerations have overcome economic concerns. This is particularly likely to occur where so large a share of government revenues arise from resource rents. The government’s adviser, Pedro van Meurs, maintains that there is little risk, stating, “I can tell you that for every one company that is planning to leave, I know of 50 new ones that are planning to come in once the door is open.”

IHS CERA’s assessment of the consequences of the PIB, if enacted in its current form, is a steep decline in investment activity because the “50 new companies” that enter will not be able to invest in the discoveries that are held by the incumbents, and it will take a long time for new activity to progress through exploration and appraisal to eventual development.

THE UNITED KINGDOM, 1993

In the UK Continental Shelf (UKCS) successive governments sought to balance the proportion of revenues taken in tax with the overall level of investment activity and maximize total government revenues. In 1993, for example, the rate of Petroleum Revenue Tax (PRT) was reduced from 75 to 50 percent, accompanied by removing the right to offset exploration and appraisal (E&A) expenditures against PRT.
The effect of the 1993 tax change was, in aggregate, a fiscal loosening for the exploration and production sector, and the government sought to present it as such. But it affected different players differently, depending on their tax position. Even for the worst affected, it reduced the operating cash flow by up to 8 percent. When adjusting for changes in the oil price over the following three years, the reduction in E&A investment was some 20 percent—despite the UK government’s providing transitional incentives to attempt to maintain investment levels.

UK employment in the oil and gas industry fell. Overall the government’s tax revenues suffered because of the damage resulting from the perceived fiscal risks caused by even an apparently favorable change.