Papua New Guinea Taxation Review (2013-2015)

Issues Paper No.1: Mining and Petroleum Taxation

Prepared by
the Committee of the Taxation Review

March 2014

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There are few areas of economic policy-making in which the returns to good decisions are so high – and the punishment of bad decisions so cruel – as in the management of natural resource wealth. Rich endowments of oil, gas and minerals have set some countries on courses of sustained robust prosperity; but they have left others riddled with corruption and persistent poverty, with little of lasting value to show for squandered wealth. And amongst the most important decisions are those relating to the tax treatment of oil, gas and minerals.

International Monetary Fund, 2010

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FOREWORD

In 2013, the O'Neill-Dion Government committed to comprehensively review PNG's revenue regime. The primary reason for the Review is to ensure that PNG's revenue regime remains relevant, efficient and effective.

Government revenue is critical to funding essential services and infrastructure for Papua New Guinea, to share the benefits of prosperity across families, communities and regions and to lay the foundations for future growth. Consequently, this Review is a high priority of the O'Neill-Dion Government and an important platform of the Government's economic and fiscal strategy.

The last comprehensive taxation review was undertaken in 2000 and given the substantial economic, fiscal and technological developments over the past 13 years, it is timely that another review is undertaken to ensure that the country's tax system is modern, robust and is able to support the country's medium and long-term economic and social development objectives. While formally titled a 'Tax Review', the Review will consider other sources of revenue, including non-taxation revenues.

This paper, the first of a series of issues papers to be released by the Tax Review Committee, is focussed on PNG's mining and petroleum fiscal regime. This early focus on mining and petroleum recognises the relative importance of natural resources to the PNG economy generally, and revenue in particular. The Committee believes that PNG needs to remain internationally competitive while ensuring that the country receives a fair share of the proceeds of mining and petroleum projects.

The following paper has been informed by work undertaken by the International Monetary Fund (IMF). Responding to an official request, in March 2013 IMF representatives met with the Departments of Treasury, Minerals Policy and Geohazards Management, Petroleum and Energy. The IMF team also met with other and relevant Government agencies and private sector representatives/entities. The Committee wishes to thank the IMF for their work.

The Committee looks forward to receiving submissions on this paper and to future engagement with interested stakeholders on the future of Papua New Guinea's tax system.

Sir Nagora Bogan, KBE
Chairman, Tax Review Committee

Tax Review Committee

The Government has appointed a Committee of 5 persons to undertake this Review. The Committee is comprised of the following distinguished Papua New Guineans, who collectively have significant experience in tax policy and administration, trade and business:

1. Sir Nagora Bogan (Chairman);
2. David Sode (Deputy Chairman);
3. Sir John Luke Crittin (Member);
4. John Lohberger (Member); and
5. Lady Aivu Tauvasa (Member).

The Review will be conducted over a period of 18 months, with the final report to be submitted to the Government by April 2015. The Committee formally commenced work on 1 September 2013.

This Committee is supported by a Tax Review Secretariat which provides technical and administrative support. The Secretariat will undertake the day-to-day activities of the Review, including research and analysis (drawing on international benchmarking, global and regional trends in tax policy, and academic work), preparing papers and briefings for consideration by the Committee, drafting reports, and arranging stakeholder consultations.

The Secretariat includes officers seconded from the Department of Treasury, Internal Revenue Commission, PNG Customs Service and the Department of Trade, Commerce and Industry. The Committee will also engage technical consultants and advisors as and where appropriate.

Objectives and Scope

The objectives of the Review are to:

- Align PNG's revenue system with its development aspirations of being a competitive middle income nation in the Asian century;

- Improve the competitiveness and efficiency of PNG's tax system so as to encourage investment, employment and economic development;
- Enhance the fairness and simplicity of PNG's taxation system;
- Recommend practical options to change PNG's tax mix between the levels of taxation on land (including resources), capital and labour;
- Improve taxpayer compliance including considering options to enhance services to taxpayers and reduce the cost of compliance through the use of modern and user friendly technology; and
- Review PNG's non-tax revenues with the aim of ensuring that fees are appropriate and fair.

The Review is broad and will include a consideration of personal income tax, corporate income tax, excise and customs tariff arrangements, the goods and services tax, mining and petroleum taxation, land, property and capital gains tax, non-tax revenue (including charges and levies), tax administration (including taxpayer compliance and the efficiency and simplicity of tax administration), small business taxation and the advantages and disadvantages of tax incentives.

Consultation Process

The Committee will consult widely with stakeholders. International experience shows that broad and effective consultation is critical to the proper design, successful delivery, implementation and sustainability of reform measures. It is expected that the Review will be conducted through three (3) stages of consultation:

Step 1. 'Blue sky' Consultation. In December 2013, the Committee (through newspaper advertisements) invited all interested parties to provide their perspectives on the broad directions for reform and key priority areas. The due date for submissions is 30 April 2014. Submissions provided as part of this consultation will help inform the direction of the Review, ensuring that key areas of public interest are addressed and building a consensus for the need for such reform.

Step 2. Consultation on Issues Papers. This will involve consultation on a series of issues papers on specific taxation areas and issues as identified above (this paper represents the first of these issues papers). The purpose of this stage of consultation is to promote more targeted discussion and debate, assisting the Committee to develop its draft recommendations. The issues papers will be released throughout 2014.

Step 3. Consultation on Draft Final Report. The final stage of public consultation will focus on the Draft Final Report prepared by the Committee. The Draft Report will draw on the feedback received in both the previous two stages of consultation and will put forward, for discussion, the Committee's proposed recommendations to Government in relation to all relevant areas of taxation and non-tax revenue.

As part of the overall Review process, consultations will include regional workshops in Port Moresby, Lae, Kokopo and Mount Hagen. Notices of the regional workshops will be advertised in the Post Courier and The National newspapers to inform the public and relevant stakeholders about the consultations.

All submissions should be sent via mail and/or email to:

Head of Secretariat
Tax Review Secretariat
c/- Department of Treasury
PO Box 542, Waigani, NCD

Email: papers@taxreview.gov.pg

Submissions in response to this paper are due by 30 April 2014.

For any other general enquiries, email: info@taxreview.gov.pg

NOTE: To aid transparency in the consultation process, all submissions will be published on the Tax Review website (www.taxreview.gov.pg) unless the submission is marked 'Confidential' with justification.

EXECUTIVE SUMMARY

This paper explores a range of mining and petroleum fiscal issues that now or in the future will affect the attractiveness of PNG as a destination for mining and petroleum investment.

The various chapters in this paper explore aspects of PNG's mining and petroleum fiscal regime, including in relation to specific fiscal instruments that are, or could be utilised. Each Chapter also contains a series of consultation questions (summarised below) that are intended to promote discussion and feedback on particular issues. However, interested stakeholders should not be bound by these consultation questions and are encouraged to provide their broader views on this area of taxation.

Many of the ensuing questions have to do with specific fiscal instruments. However, the determinant effect of these to PNG's attractiveness as a place to invest is the overall fiscal package, which comprises all of these fiscal instruments.

Accordingly, many of the questions are interrelated, and the implementation of certain possible changes may need to be balanced against the adoption of others to achieve an overall package of deliverable reforms. In particular, a number of possible changes which relate to reducing the challenges faced by the Internal Revenue Commission, the Mineral Resources Authority, the Department of Minerals Policy and Geohazards Management, the Department of Petroleum and Energy and other State agencies in administering the fiscal regime. Possible changes could be made to remedy this vis-à-vis; (i) reducing the number of fiscal instruments, (ii) rationalising the number of rules relating to them, (iii) reducing the need for State involvement in project negotiations, and (iv) using published template agreements.

At the same time, some possible changes could provide a more transparent fiscal regime to potential investors which could consequentially improve governance and level the playing field. In considering possible changes, revenue constraints and integrity are also important considerations.

Consultation questions

Below are the various consultation questions posed throughout the paper. As noted above, they are intended to act as prompts only and stakeholders should feel free to raise any other related views/issues.

Exploration

Question 4.1 – do stakeholders consider that the current process of awarding exploration licenses in PNG is appropriate? Why or why not?

Question 4.2 – in principle, should PNG consider moving towards a competitive tendering process based upon cash bidding? If so, should this process be applied to outstanding applications, with a moratorium introduced for the issuing of new applications until such a process is put in place?

Question 4.3 – is the double deduction still required as an incentive to promote exploration, given the changes in PNG since it was first introduced?

Question 4.4 – should the 10 percent annual taxable income cap limitation on deducting exploration expenditure be removed?

Aligning Income Taxes

Question 5.1 – provided a suitable rent tax is introduced for mining projects (see Chapter 6), should new mining projects continue to be subject to a 30 percent income tax rate with a dividend withholding tax rate of 10 percent?

Question 5.2 – provided a suitable rent tax is introduced for petroleum projects, should new petroleum projects be subject to a 30 percent income tax rate with a dividend withholding tax rate of 10 percent?

Question 5.3 – what are stakeholders' views on ensuring that there are third party access arrangements over the PNG LNG and any new gas project midstream and downstream infrastructure? What issues might arise in introducing such arrangements?

Question 5.4 – provided that a suitable rent tax and third party access arrangements over midstream and downstream infrastructure are in place, should new gas projects be subject to a 30 percent income tax rate with a dividend withholding tax rate of 10 percent?

Question 5.5 – should the deduction of a buyer of a mining or petroleum interest be limited to the undeducted allowable capital expenditure and allowable exploration expenditure of the vendor?

Question 5.6 – in addition to the piercing of the ring fence, should taxpayers be allowed to make contributions to a mine closure trust to bring forward deductions for decommissioning expenses into the income producing phase of a ring fenced project?

Question 5.7 – should the application of the gas oil ratio test be measured on the basis of resource extracted to product marketed? What issues might arise with such an approach?

Question 5.8 – should separable hedging gains and losses be taxed outside of the project ring fence, under the standard income tax regime?

Question 5.9 – should depreciation deductions be pro-rated in the first year of production?

Question 5.10 – what other changes to Division 10 of the *Income Tax Act 1959* could made to align the income tax treatment of designated gas, petroleum, and mining projects?

Design of a Resource Rent Tax

Question 6.1 – do stakeholders agree with the pros and cons of state equity participation as described? What other factors might be relevant when considering the benefits of State participation?

Question 6.2 – what are stakeholders' views on the value of the State having a carried interest in a project?

Question 6.3 – as a general principle, do stakeholders agree that the State should focus on ensuring it collects a proportion of any resource rents in new projects through an appropriately framed fiscal instrument rather than through State participation?

Question 6.4 - what are stakeholders' views on the various fiscal instruments discussed as a means of capturing resource rents? Which model might be most appropriate in PNG's context and why? Should consideration be given to extending an amended Additional Profits Tax across the various sectors?

Question 6.5 – should affected landowners be given the right, but not obligation, to acquire 20 percent of a project on commercial terms, to be exercised on or before the grant of the relevant development licence?

Royalty and Development Levy

Question 7.1 – do stakeholders agree that royalty rates should be maintained, with a focus instead on developing an appropriately framed resource rent tax?

Question 7.2 – for new petroleum and gas licences, should a field gate value basis royalty determination be used instead of a wellhead one?

Tax Incentives

Question 8.1 – what are stakeholder's views on the provision of tax incentives for the mining and petroleum sector? Should special reductions in main fiscal rates not be granted to any new mining or petroleum projects?

Question 8.2 – should the infrastructure credit scheme be replaced with an infrastructure 150 percent deduction scheme, with an increase in the annual cap to two percent of assessable income?

International Aspects of the Mining and Petroleum Fiscal Regime

Question 9.1(a) – should PNG retain the thin capitalisation debt to equity limit applying to mining and petroleum projects when reductions are occurring in neighbouring jurisdictions?

Question 9.1(b) - Would 2:1 or 1.5:1 be more representative of commercial gearing levels in PNG's Mining, petroleum and gas sectors?

Other issues

Question 10.1 – should the withholding rate on royalties paid by resource projects to landowners be increased to the prevailing lowest positive personal income tax rate?

Question 10.2 – should template project agreements that will form the basis of any new project agreements within the country be developed and published?

Question 10.3(a) provided a suitable rent tax is imposed on resource projects, should the *Resource Contracts Fiscal Stabilisation Act 2000* not apply to new projects?

Question 10.3(b) otherwise, should fiscal stability obtained in exchange for a two percent tax rate premium be made symmetrical, time limited and limited to key rates of tax and duty and explicitly listed capital allowances?

Question 10.3(c) - what are stakeholders' views on offering 'most favoured taxpayer provisions' or 'indemnification/compensation provisions'?

Question 10.4 – should a GST deferral scheme be introduced so that the payment of GST on imports is delayed until filing the next GST return, at which time there will be a credit available offsetting the potential GST on the imported equipment?

Question 10.5 – should import duty exemptions or lower rates be given to specifically listed specialised equipment not available in the market, and with the requirement that the equipment be re-exported after use if there is any remaining economic life?

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CHAPTER 1: PNG'S MINING AND PETROLEUM SECTORS

Over the past decade, Papua New Guinea's mining and petroleum sectors have been significant contributors to economic growth of the country. This is expected to continue into the foreseeable future. These two sectors account for around 75 percent of exports and 20 percent of gross domestic product. The sectors have also been an important but volatile source of revenue for the country.

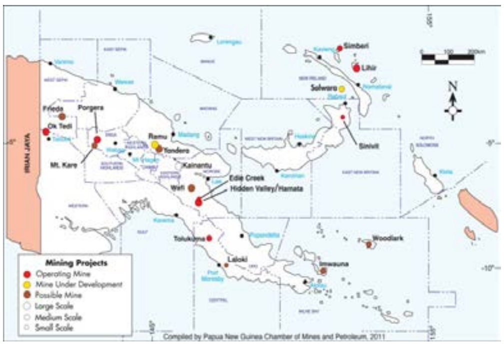
The following is an overview of the current status of the sectors as well as their revenue generating performance.

Overview of PNG's Mining Sector

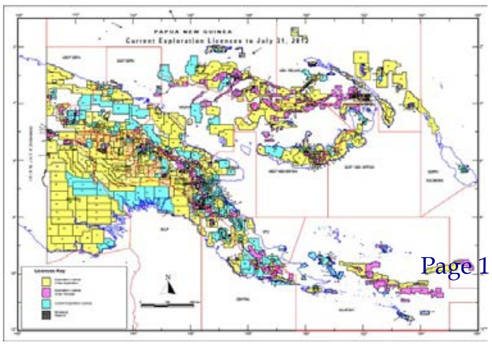
The investment climate for mining is more positive now than 10 years ago. Two (2) major mining operations have commenced production; Hidden Valley (2008) and Ramu (2012) as well as smaller gold mines at Kainantu, Sinivit, Simberi and Woodlark and also the Yandera copper operation. Two (2) new major potential copper-gold projects are either in the prefeasibility stage (Wafi-Golpu with the prefeasibility for Golpu still under preparation) or the feasibility stage (Frieda River). The other promising prospects include Hessen Bay, Mt. Kare and Imwauna as well as the potential Solwara seabed mining operation. Figure 1 shows PNG's current mining projects.

The total area of land of PNG covered by exploration licenses and license applications has also increased from about 20 per cent a decade ago to nearly 100 per cent today. This is largely the result of a worldwide boom in minerals prices, which started around 2004 and which has resulted in the world market price of most minerals doubling, tripling, or more today. Refined copper prices for example have increased from about $2,000 per ton from 2000-2004 to about $7,600 per ton today.

Figure 1. Map of mining activities and exploration licenses



Source: PNG Chamber of Mines and Petroleum



Source: MRA

Overview of PNG's Petroleum Sector

Papua New Guinea has been a small oil exporting country since 1992 and is expected to become a significant gas exporter from the end of 2014. Exploration in PNG began 60 years ago. A series of onshore gas discoveries were made in the 1960s and 1970s. Due to their location and limited size they were not considered as commercial.

The first oil discoveries were made in the 1980s in the Highlands, notably the Kutubu field, a relatively large 375 million barrels oil field (Figure 2). Other oil discoveries were made but were of considerably smaller sizes - in the range of 10-100 million barrels.

Production and exports started in 1991 and rose to a peak of 126,000 barrels per day in 1997 declining to 26,500 barrels per day in 2012. Today cumulative oil production has reached 485 million barrels while the remaining proven and probable reserves are estimated at 75 million barrels which is only 13 percent of the initial reserves.

Several projects were studied for monetising the stranded gas resources from several discoveries and a firm investment decision for the large PNG LNG project was taken in late 2008. This project consists of the aggregation of the gas associated with the oil extracted from four oil producing fields and the exploitation of three non-associated gas fields which are all located in the Highlands and when combined have total gas reserves of 9 trillion cubic feet (Tcf). The gas will be transported by a pipeline, consisting of an onshore and offshore line, to a two-train[1] 6.9 million ton per annum (tpa) liquified natural gas plant located close to Port Moresby. The integrated project is of international standards involving capital expenditure of around $19 billion including upstream, pipelines and liquefied natural gas plant facilities.

Three (3) other gas monetising projects are under consideration. These are:

- The InterOil liquefied natural gas project which is the most advanced with an objective of 9 Tcf from recent very promising gas discoveries.[2]
- The tentative Gulf province liquefied natural gas project with an objective of two to three Tcf.

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[1] In the context of an LNG Plant a 'train' refers to a liquefaction a purification facility that reduces the volume of LNG, making it commercially viable to transport.

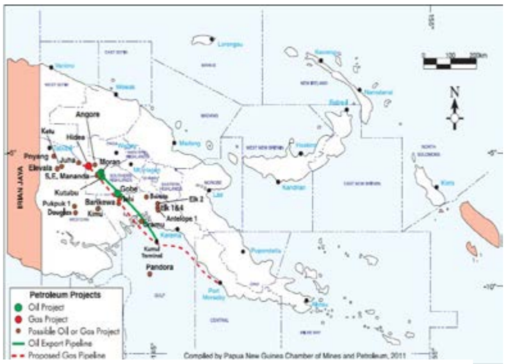
[2] In late 2013, InterOil announced the same of a portion of its proposed LNG project to Total S.A – see InterOil press release dated December 5, 2013 available from http://www.interoil.com

- The potential offshore aggregation project where further exploration in the old Pandora-Pasca discoveries areas is in progress to identify new discoveries.

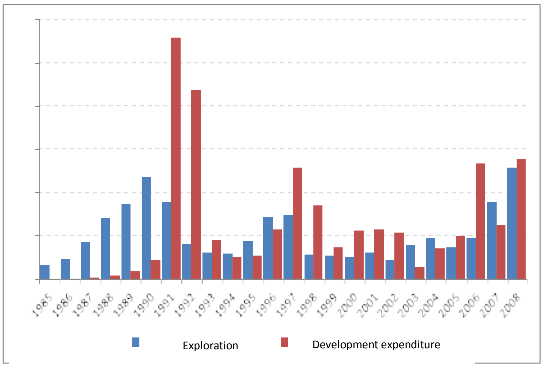
In addition to the above projects, significant investment in exploration has taken place in recent years (see Figure 2). The level of activity dropped from the end of the 1990s until the mid 2000s as a consequence of low oil prices and a relatively low exploration success ratio, with only a limited number of new prospecting licenses awarded. In the last five (5) years, following the rise in oil prices and the announcement of the PNG LNG project, the country has attracted more interest from small to large companies.

Today most of the petroleum prospective areas are covered by licenses and more applications are under examination. Regular farm in/farm outs[3] are also taking place and this is expected to accelerate exploration. This is notwithstanding that onshore exploration and development operations in the country are considered extremely expensive,[4] due to the highly mountainous terrain and the absence of infrastructure. The absence of the use of 3D seismic technology onshore also increases uncertainty. PNG's offshore operations are however more comparable to offshore operations in other countries.

Figure 2. Map of oil and gas activities and evolution of exploration and development expenditures in Papua New Guinea



Source: PNG Chamber of Mines and Petroleum



Source: PNG Chamber of Mines and Petroleum

[3] Broadly, a 'farm-in, farm-out' arrangement is one where the owner of an interest in a natural gas/oil lease assigns their interest or part of their interest to another party to drill on the land. The interest received by the assignee is a 'farm-in' whilst the interest received by the assignor is a 'farm-out'.

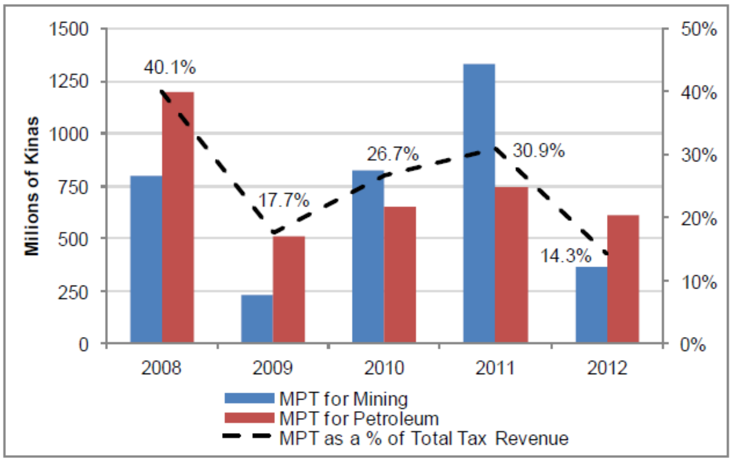
[4] The average technical cost, including exploration, development, pipeline and operation costs, over the 1985-2008 period was $16.2 per barrel, in nominal dollars. During the same period the average oil price was near $30 per barrel. Source: the PNG Chamber of Mining and Petroleum.

Revenue Levels and Trends

Undoubtedly, taxes from the mining and petroleum sectors are a significant source of government revenue, but this can be volatile. Figure 3 illustrates the volatility of revenues from mining and petroleum taxes. This is due mainly to the unpredictability in commodity prices (note: the Figure excludes royalty and dividends).

The decline in revenue from the petroleum sector is also due to the gradually declining oil production, although the new liquefied natural gas project will provide a new source of revenue from the petroleum sector. As can be seen from Figure 3, the extractive industries are a significant source of overall tax revenue.

Figure 3. Tax revenue from Mining and Petroleum Sectors 2008-2012



Source : IRC

CHAPTER 2: PNG'S MINING AND PETROLEUM FISCAL REGIME

Fiscal Regime for the Mining Sector

The fiscal regime for mining is largely contained in Chapter III, Division 10 of the *Income Tax Act 1959* (ITA 1959). Furthermore, provisions for mineral royalties and the Government's right to take equity in a mining project are contained in the *Mining Act 1992*. However, as with oil and gas, the fiscal regime in the mining sector can be modified by special agreement. There is also a provision in the *Mineral Resources Authority Act 2005* for a mineral levy to fund the operations of Mineral Resources Authority.

Mining companies are subject to the standard company income tax rate of 30 percent,[5] however, the ITA 1959 provides a number of concessionary tax rates and incentives. These include, inter alia:[6]

- Mining companies paying a dividend withholding tax of 10 percent (compared with the normal dividend withholding tax of 17 percent (ITA 1959 subsection 42(3) and *Income Tax & Dividend (Withholding) Tax Rates Act*).[7]

- Mining companies and lenders having a zero interest withholding tax for mining projects (ITA 1959 subsection 35(2)), compared with 15 percent for other sectors. Also, lending for mining is restricted to a 'thin capitalisation' maximum debt:equity ratio of 3:1 for tax purposes (which compares to 2:1 for other non-banking sectors).

- Mining as well as oil and gas companies can carry forward tax losses indefinitely (ITA 1959 section 101) while other companies are subject to a 20 year limitation.

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[5] The normal company income tax rate of 30 percent applied to resident mining companies is the same as other resident companies. Non-resident mining companies pay 40 percent whereas other non-resident companies pay at 48 percent (*Income Tax & Dividend (Withholding) Tax Rates Act*).

[6] These provisions and references to the ITA 1959 and other legal instruments are taken from '*Guide to the Taxation Incentives Business and Investment in Papua New Guinea*' PNG Internal Revenue Commission draft dated 9 February 2012 which is quoted extensively in this section.

[7] All the withholding taxes in the section may be reduced through double taxation agreements.

- The infrastructure tax credit (ITA 1959 section 219C) is another incentive available for mining (as well as oil, gas, tourism and primary producers) companies to provide infrastructure to local communities.

- Mining companies are permitted to double the value of exploration expenditures for depreciation purposes. Exploration expenditures from areas outside the project area may be pooled and deducted at 25 percent declining balance subject to certain restrictions (ITA 1959 section 155N).

- Like most other countries with mining activities, minerals projects are zero rated for GST purposes. This is the same as oil and gas (Division 7(f) and 20(d) of *Goods and Services Tax Act*).

- Mining companies are subject to import duties while most companies have negotiated concessionary rates.

- Mining companies (as well as oil and gas companies) receive a concessionary rate for the contractor's withholding tax of 12 percent (17 percent for other sectors of the economy).[8]

- Mining companies have a concessionary stamp duty rate for the transfer of mining information, and along with oil and gas companies, concessionary rates on the transfer of an exploration or development license (*Stamp Duties Act*).

- In addition to the exemption of one annual leave fare from place of employment to the place of origin or recruitment, employees of resource companies that can demonstrate 'hardship and remoteness of the employment location from urban centres' are entitled to: (i) exemption on their domestic fares within PNG and, (ii) an additional exemption on their international fares (ITA 1959 section 40AA).

Mining companies can enter into a fiscal stability agreement with the State. This guarantees stability in respect of certain taxes, duties and fees (*Resource Contracts Fiscal Stabilisation Act 2000*).

Mining was previously subject to an additional profits tax which was abolished from 6 June 2002. Thus, there are no progressive tax instruments for taxing the economic rent of highly profitable projects in the mining sector.

[8] This can be reduced in double tax agreements.

The main fiscal rates are presented in Table 1. These rates also compare with the average rates found in other mining jurisdictions. Although they are concessionary rates with regard to the general taxation provisions for PNG, the rates for company income tax and dividend withholding tax are, apart from the level of royalties, broadly in line with those of other mining countries. The difference between these provisions and the general income tax provisions has some ramifications on the integration versus segregation of projects.

Table 1. Comparison of Papua New Guinea's mining fiscal instruments and rates with other countries

Instrument	Papua New Guinea (in percent)	Other Mining Countries (in percent)
Corporate Income Taxes (CIT)	30	30
Dividend Withholding Tax (DWT)	10	11
Royalties and Levies – Copper	2.25	4
Royalties and Levies – Gold	2.25	4
Interest Withholding Tax	0	Various but often reduced to zero by DTAs
GST /VAT on exports	0	Most 0
Import Duties	One mine exempt Others pay a range of sometimes reduced import duties	Most are exempt
Contractors Withholding tax	12 (1)	Various
Depreciation	25 percent declining balance Exploration 100 percent uplift	Various

(1) This can be reduced under double tax agreements.

Mining agreements can vary fiscal terms. With the exception of Ok Tedi which operates under its own Act (the *Ok Tedi Act 1984* and subsequent amendments) each major mining project operates under a Special Mining Lease for which a mining development contract was issued.

Based on the available information, there do not appear to be any significant variations of fiscal terms in mining development contracts. The one very important exception is the Ramu Nickel project which was granted an exemption from import duties and a 10 year tax holiday. However, as noted in Table 1 above, some other mining projects do operate with reduced import duties.

Fiscal Regime for Petroleum Products

The ITA 1959 provides for different tax regimes applicable respectively to 'petroleum projects' and 'designated gas projects' which are defined in the *Oil and Gas Act 1998* (OGA) and ITA 1959. The basis for determining the assessable income of a taxpayer is per project with strict project ring fencing. A petroleum project may produce oil and natural gas.

A designated gas project exists when a gas agreement has been signed with the minister responsible for petroleum, otherwise the tax regime of petroleum projects applies. A gas project may produce natural gas and incidental liquids (oil, condensates, and natural gas liquids). The tax framework of each regime covers both upstream (exploration, development and production) and midstream operations (such as pipelines, storage and terminals, and processing facilities).[9]

PNG's legal and regulatory framework for exploration and production of oil and gas is governed by the OGA. The OGA is very detailed and covers upstream, pipelines and processing plants. It provides for the granting of licenses on (i) exploration (petroleum prospecting license or PPL), (ii) further assessment of gas discoveries (petroleum retention license or PRL), (iii) exploitation of commercial fields (petroleum development license or PDL), (iv) pipelines (pipeline license), including 'strategic pipelines' which may be used by third parties, and (v) processing plants including liquid natural gas plants (petroleum processing facility license). Licenses are issued by the responsible minister (i.e. the Minister for Petroleum and Energy). Under the OGA, 'petroleum' includes oil and natural gas, and a 'petroleum project' designates a project for production of oil and gas and its related facilities for transportation and processing, which is not designated as a gas project.

Under the OGA there is a distinction between oil fields and gas fields which may lead to a difference in fiscal treatment in the case of conversion to a gas

[9] This classification per type of project is the basis for income tax and additional profits tax purposes in PNG. It is different from systems where oil and gas production are assessed differently.

project. A 'gas field' is a petroleum field where 'oil recovery is not expected to be the primary object of petroleum'. A 'gas oil ratio' exceeding 6,000 cubic feet per barrel of oil may allow the conversion of an existing oil field to a gas field. In this context, 'gas operations' mean all the petroleum operations related to the recovery, transportation and processing of 'petroleum' extracted from a gas field, which comprises natural gas and the associated liquids. A 'gas project' means a project dealing with the recovery of gas, and of incidental petroleum governed by a specific 'gas agreement' while a 'petroleum project' is dealt with by a 'petroleum agreement'.

Petroleum and gas agreements are entered into between the Minister of Petroleum and Energy, on behalf of the State, and the concerned licensee. A petroleum agreement may provide for the purposes of the OGA and any other law (OGA section 183), for the definition and terms of a particular petroleum project, the conditions for the State equity interest (such as the designation of the appointee and the maximum equity interest) and any other matters. A gas agreement applies similarly regarding a gas project.

The scope and provisions of such agreements may vary from one contract to another. Such agreements may (i) contain tax concessions, which are the result of negotiation for a specific petroleum or gas project (ii) be in conflict with existing laws, which requires the amendment of existing laws when such conflict exists, to allow the smooth enforceability of the agreements[10] and/or (iii) contain a stabilisation clause and a non-discriminatory clause. Currently, petroleum gas agreements are kept under strict confidential conditions. A new model agreement for each type is currently under preparation.

The *Resource Contracts Fiscal Stabilisation Act 2000* authorises the granting of stabilisation rights. In particular, fiscal stability agreements related to petroleum, gas, mining agreements may be entered into under this Act. The Committee is not aware of any fiscal stability agreements applicable to the oil fields currently in production (PDL one to six).

The OGA provides for several tax and fiscal instruments (other than income tax), in particular for fees, royalty, development levy, State and landowners equity entitlements and project benefits for the local communities and governments. These fees address license applications and annual surface license fees.

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[10] For example, after the signing of the PNG LNG project gas contract , the ITA 1959 was amended thereby changing the terms of the existing additional profits tax system.

Under Section 159, the royalty is fixed at two percent of the wellhead value on all 'petroleum produced from the license area.' An additional two percent development levy, calculated on the same basis then the royalty, is also payable by the licensee to local-level and provincial governments (OGA section 160).

The effective impact of the royalty and development levy is equivalent to a two percent royalty. This is because subsection 159(4) of the OGA provides that the royalty is considered as an advance on the income tax due by the licensee (the so-called credited royalty instead of the traditional expensed royalty system). This tax treatment is confirmed by the ITA 1959.

Under the OGA, the State is entitled, without any obligation, to an equity interest not exceeding 22.5 percent in each petroleum project or gas agreement (OGA section 165). The terms and conditions for exercising this benefit are specified in the petroleum or gas agreement related to the concerned petroleum project. Generally, this option has to be elected when the PDL related to the petroleum project is issued, subject to the reimbursement by the State (or its nominee) of its proportionate share in the sunk costs of the project up to that date and to fund its share of all future costs for development and exploitation related to the project.

The OGA provides for a series of benefits in favour of the landowners, and local and provincial governments (sections 167 to 179). From its equity and royalty interests in a petroleum project, the State may allocate a portion to the affected landowners, and local and provincial governments. No specific percentage is stated in the law.

The State may also enter into development agreements with such entities for awarding project related grants. The State may also benefit from infrastructure directly funded and built by the licensee with their prior approval, and such costs are directly creditable against the payable income tax, subject to the limitations stated in the ITA 1959. Globally, the total benefits granted to the landowners, and local and provincial governments cannot exceed 20 percent of the total net benefits to the State from the petroleum project during its life (section 174).

The applicable tax regime for petroleum activities is governed by the ITA 1959 and is summarised in Table 2 below.

Table 2. Summary of the Petroleum Fiscal Regime

Fiscal Instruments	Petroleum projects	Gas projects	Comments
Royalty and development levy	2%	2%	On wellhead value.

Petroleum income tax	50% (old fields), 45% (standard) or 30% (incentive rate)	30%	Depreciation schemes: Exploration (25% DB), Long Life (10 years SL) and Short Life (25% DB).
Ring fencing for tax	Per project	Per project	May include pipelines and processing facilities. Exploration in the country deductible with a limitation.
Uplift for depreciation under	No	Only for PNG LNG Project	From 0 to 50% depending on R factor at year 11.
State participation option	Up to 22.5%	Up to 22.5%	To be elected when development is decided. Revenues for government only if State owned enterprise transfers dividends.
Additional profits tax	None (abrogated in 2003)	•Reduced two-tier APT applies to gas projects only •Thresholds: 17.5% and 20%	Original two-tier APT from 2001 to 2003: Thresholds: 15% and 20% APT rates: 20% and 25%
Other taxes	Taxation of subcontractors and personnel. withholding tax on dividends or interest. No capital gains		

In particular, Division 10 of ITA 1959 deals with the specific rules applicable to mining, petroleum and designated gas projects such as ring fencing, depreciation of capital expenditures and exploration expenditures, loss carry forward, deductibility of interest, treatment of sale of property and transfer of interest, applicability and terms of an additional profits tax limited to designated gas projects, and conversion of a field that is part of a petroleum project to a gas project from a conversion date.

The income tax rate applicable to petroleum taxpayers is defined in Schedule 4 of the ITA 1959. It is different from the normal company income tax rate (referred to hereafter as the petroleum income tax rate). Today it is fixed at 30 percent, for 'designated gas projects', and as an incentive for the 'petroleum projects' derived from PPLs issued or renewed in the 2003-2007 period and the related PDLs issued over the 2003-2017 period (the 'petroleum income tax incentive rate'). For other new petroleum projects the rate is 45 percent. The petroleum income tax rate has been kept at 50 percent for petroleum fields already in production at the end of 2000.[11]

[11] Of the five (5) oil fields currently producing in Papua New Guinea, one is subject to a 45 percent rate (PDL six NW Moran) while the others (Kutubu, including pipeline license No. 2), SE Mananda, Gobe (PDL three & four) and Moran (PDL five) are liable to the old 50 percent rate.

The tax regime applicable to petroleum and gas projects has changed several times since the major reform of 2000 in a bid to encourage further investments. Additional tax incentives for new projects were also introduced in 2003, both for oil and gas. This included removing the additional profits tax for all projects, including for oil fields already in production, and introducing reduced petroleum income tax rates of 45 or 30 percent.

In 2008 the additional profits tax was reintroduced for designated gas projects only, aligning its terms to those negotiated for the PNG LNG project, by amending the ITA 1959 (section 159C) applicable to all new gas projects. A special incentive was introduced in the law. But this was limited to the PNG LNG project, allowing a possible 'capital uplift' as an additional deduction for allowable capital expenditures if the gas project has not reached the stated R-factors of 1.91-2.36 at the end of year 10 of the production (ITA 1959 section 158J).

Division 10 of the ITA 1959 provides that tax liabilities are borne individually, both for income tax and additional profits tax (when applicable), by each entity constituting the PDL licensee in respect of its interest in a given petroleum or gas project.

Due to the project ring fencing, a taxpayer participating in several PDLs and projects submits a separate tax return for each individual project. The applicable tax regime in each case depends on the date of issue of the related PDL and the terms of the applicable agreement when special conditions applied (which then must be reflected in the ITA 1959). Special provisions in the ITA 1959 allow for deduction of exploration expenditure incurred by a taxpayer or its affiliates outside the PDL area but subject to limitations.

The ring fencing under Division 10 also provides that costs related to activities other than petroleum activities in PNG are not deductible for a given project. Such exclusion is common in tax regimes applicable to upstream activities. The activities not directly related to the petroleum operations are considered for tax purposes as a separate business.

Fiscal Regime for Natural Gas Projects

In PNG the tax regime applied to designated natural gas projects varies from the petroleum project tax regime. The main differences concern the income tax rate and the application of the additional profits tax. The other fiscal provisions are identical. As applies to petroleum projects, a gas project deals with upstream operations but may also include midstream facilities, such as pipelines, gas processing plants and liquefied natural gas plants if so provided for in the gas agreements.

The applicable income tax rate for gas projects is 30 percent. It is equal to the incentive rate for new petroleum projects which meet certain conditions in terms of vintage, but is lower than the base rate of 45 percent.

Different from petroleum projects, an additional profits tax was reintroduced for designated gas projects in 2008. The reintroduction of the gas additional profits tax was the result of negotiations under the PNG LNG project. The 2008 additional profits tax rates are significantly lower than under the old additional profits tax that applied in PNG. Table 3 shows the evolution of the additional profits tax schemes in PNG and of the marginal government takes depending on the fiscal case.

Table 3. Evolution of additional profits tax (APT) schemes and marginal government take (MGT) in PNG

Period	**Type of APT**	**Threshold rates**	**APT Rates**	**MGT w/o State Equity (1)**	**MGT with State Equity (1)**
Before 2001 (petroleum & gas)	One-tier ROR APT	27%	50%	51% (No APT) 76% (APT)	62% (No APT) 81% (APT)
2001-2003 (petroleum & gas)	Two-tier ROR APT	15% and 20%	20% and 25%	From 46% (No APT) to 68% (APT)	From 58% (No APT) to 75% (APT)
Post 2008 (gas)	Two-tier ROR APT	17.5% and 20%	7.5% and 10%	From 31% (No APT) to 43% (APT)	From 47% (No APT) to 56% (APT)
Post 2003 (petroleum)	No APT	n/a	n/a	From 31% to 46%	From 47% to 58%

(1) MGT: marginal government take for the fiscal case stated, considering the interaction between royalty, income tax, additional profits tax (if any) and State participation (if any); rounded to the nearest percentage point. MGT determines additional revenue for the State on a profitable project for one additional dollar of revenue raised (for the project). Assumptions: 1.6% effective royalty rate on free on board value (corresponding to 2 % on a well head basis); 22.5% State equity for MGT with equity; income tax rate: 50% before

2001; 45% after 2001; and 30% for gas (and oil incentive rate) and 45% for oil after 2003.

As illustrated in Table 3, the current applicable additional profits tax system for gas projects is not highly progressive. This is leading to relatively low government take when profitability of a project increases. The reasons are, firstly, that the first threshold rate is high (17.5 percent), and secondly that the two (2) additional profits tax rates are low (7.5 percent and 10 percent leading to a maximum additional profits tax of 16.75 percent when the two rates apply).

CHAPTER 3: FISCAL PACKAGE DESIGN

This Chapter explores some of the high level issues that may be relevant when considering the design an overall fiscal package to apply to the petroleum and mining sectors.

Government's Resource Commercialisation Role

Since the exploration, extraction and processing of minerals and petroleum requires very specialised knowledge and skills, such undertaking are ordinarily carried out by globally mobile private firms. As the resources available to these firms is limited, PNG needs to ensure that its overall investment climate does not impose undue barriers to attracting necessary capital and expertise.

At the same time, PNG's mineral and petroleum resources are a finite and non-renewable resource. Their extraction permanently depletes PNG's inventory of resources, and the right to extract them allows private firms to potentially gain surplus revenues in excess of all costs of production. Accordingly, PNG needs to manage and ensure that the exploitation of these non-renewable resources is done in a way that maximises the economic benefits to the citizens of the country.

The Importance of the Fiscal Regime

Table 4 below illustrates the result of a survey on the factors that determine the attractiveness of a jurisdiction as an investment destination. It shows that the fiscal regime – described as 'method and level of tax levies' – rates only 16th in order of importance for exploration decisions, and 13th in order of importance for mining decisions.

Of greater importance are those factors related to geology, profitability, and stability – uncertainty and risk are major deterrents to the attractiveness of a country as an investment destination for mining and petroleum.

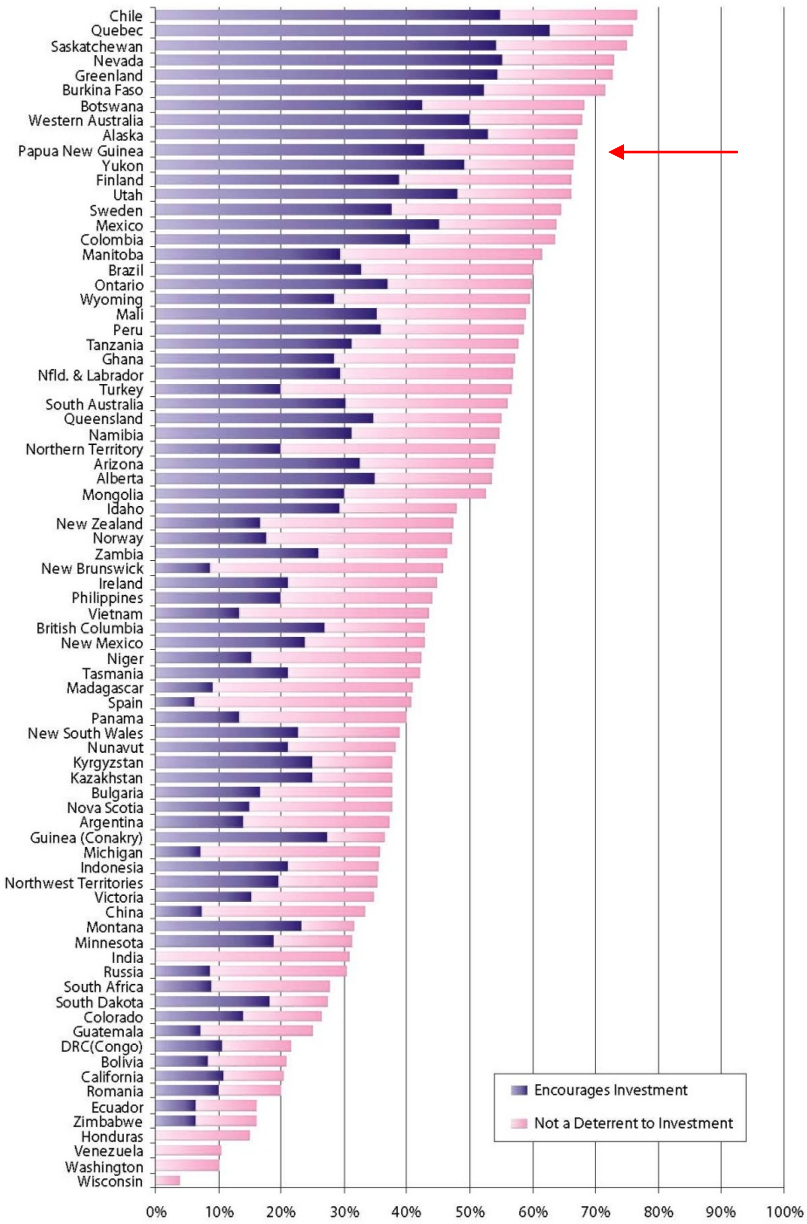
Table 4. Factors that influence a country as an investment destination

Exploration Stage	Mining stage	Decision criteria
1	N / A	Geological potential for target mineral
N / A	3	Measure of profitability
2	1	Security of tenure
3	2	Ability to repatriate profits
4	9	Consistency and constancy of mineral policies
5	7	Company has management control
6	11	Mineral ownership
7	6	Realistic foreign-exchange regulations
8	4	Stability of exploration/mining terms
9	5	Ability to predetermine tax liability
10	8	Ability to predetermine environmental obligations
11	10	Stability of fiscal regime
12	12	Ability to raise external financing
13	16	Long-term national stability
14	17	Established mineral titles system
15	N / A	Ability to apply geological assessment techniques
16	13	Method and level of tax levies
17	15	Import–export policies
18	18	Majority equity ownership held by company
19	21	Right to transfer ownership
20	22	internal (armed) conflicts
21	14	Permitted external accounts

Source: Fraser Institute Poll 2010/11

On geology, the investor perception of PNG's geology is highly positive (Figure 4).

Figure 4. Attractiveness of Papua New Guinea's geology to investors



Source: Fraser Institute Poll 2010/11

On profitability, the risks in delivering a project in PNG as perceived by investors has reduced considerably. This is due to the forthcoming successful completion of the US$19 billion PNG LNG project, a number of operating mines including two new major mining projects, and continued interest from foreign investors in future mining and petroleum projects. PNG now has a reputation as a mature mining and petroleum jurisdiction where complex resource extraction projects can be successfully undertaken. This, along with PNG's geology and continuing macroeconomic stability, will help it to maintain its attractiveness to investors.

Even though PNG's geology is good and the successful completion of the PNG LNG construction will continue to sustain the country's reputation as a place to invest in, there is nevertheless a temptation, as is the case with all countries, to alter the fiscal regime in response to changes in the global commodity markets. When commodity prices are high, the temptation is to increase the burden placed on mining and petroleum projects to extract more revenue for the State. When commodity prices are low, the temptation is to reduce the burden placed on mining and petroleum projects to try and attract additional investment.

Figure 5 shows how the level of global exploration expenditure changed throughout the 2000s, and the temptation for governments to change their fiscal settings to accommodate the prevailing commodity market conditions. When commodity prices are high, there is political pressure for the community to receive a higher proportion of project revenues. When commodity prices are low, there is political pressure to try and attract an increasingly scarce pool of capital.

Figure 5. Stability versus temptation to change the fiscal regime

Global exploration expenditure:

- 1997: US$5.2 billion
- 1998: US$3.7 billion
- 1999: US$2.8 billion
- 2000: US$2.6 billion
- 2001: US$2.2 billion
- 2002: US$1.9 billion

Temptation to lower taxes

- 2003: US$2.4 billion
- 2004: US$3.8 billion
- 2005: US$5.1 billion
- 2010: US$ 10 billion

Temptation to raise taxes

This variability in fiscal settings however, gives rise to instability – the very thing that Governments can control to attract investment by mining and petroleum exploration and extraction companies. To promote stability and remove temptation to continually readjust the fiscal regime to suit the prevailing circumstances at the time, one approach would be to implement a fiscal package that is *progressive*. That is, a fiscal package that automatically responds to prevailing commodity prices – to enable collection of a greater share of revenues when times are good, and a smaller share when times are bad.

The use of a progressive fiscal regime would arguably improve the country's reputation as a stable destination for investment, as well as improve its political acceptability.

Taxing Resource Rents

Progressiveness of a fiscal regime also helps ensure that a country is able to tax a resource rent. A resource rent is the extra revenue a project is able to gain as a result of the right to extract resources, over and above the 'normal' return that would otherwise be available to the capital invested in the project.

Taxing these rents is efficient because doing so should have a minimal effect on decisions about whether to invest or not. It is also fair because these rents come from the non-renewable resources that belong to a country.

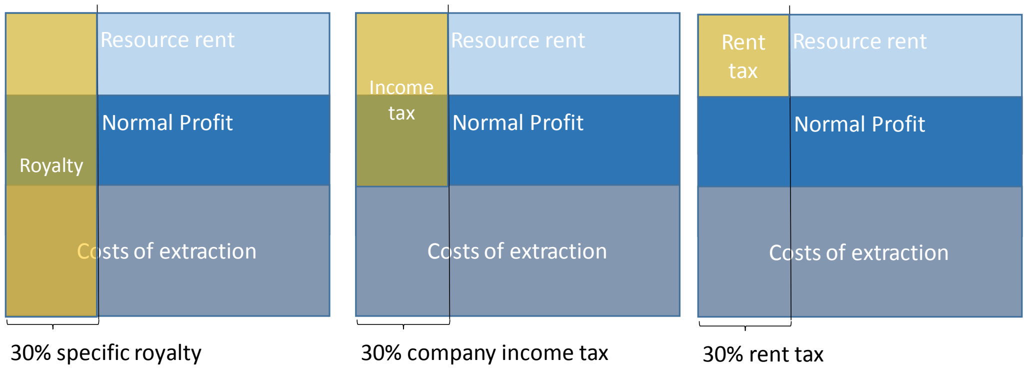
Figure 6 seeks to illustrate the difference between a rent tax and an income tax or (specific per unit) royalty. The diagram splits the profit earned by each of the three projects into two (2) types – the 'normal profit' that the capital invested could have obtained elsewhere in PNG; and the 'resource rent', which is profit earned only because of the right to extract resources.

The left hand diagram shows the effect of a specific royalty, which creates a great disincentive to investment. This is because the project must pay to the State a share of costs as well as profits. If the project were marginally profitable, the royalty could have the effect of making the project uneconomical – this comes at a cost to both the project supporter and the State.

The middle section of the diagram shows the effect of an income tax. The income tax greatly lessens the disincentive to investment, because only profits are taxed. However, if the income tax on mining and petroleum projects were increased in an effort to capture a greater proportion of rents, then there is a higher risk that the capital invested in the project could be mobilised elsewhere in PNG so as to enjoy a lower rate.

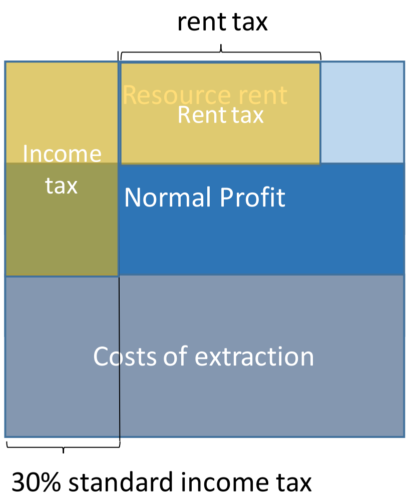
The right hand side of the diagram depicts the effect of a rent tax. The rent tax marginally lessens the disincentive to investment, because the normal profit on the project investor's capital is untaxed by the rent tax (and in practice, taxed only by the standard company income tax). At an extreme, a large proportion of the rents could be taxed without imposing a disincentive to investment. This is arguably appropriate, as the rents represent the value of the resource, which is owned by the country.

Figure 6. Royalties versus Income Taxes versus Rent Taxes



Accordingly, a fiscal regime that combined a standard tax and a rent tax to capture the parts of a project's revenue as depicted in Figure 7 would theoretically be ideal. The normal profit on capital is taxed under the standard income tax regime, and a large proportion of rent taxes are taxed under a specific rent tax. Some rent taxes remain untaxed, as the scarcity of global capabilities to explore and extract resources alluded to in the beginning of this chapter suggests that there are some firm specific rents that should remain untaxed.

Figure 7. An ideal combination of standard income tax and rent tax



In spite of the attractiveness of the concept, in theory, it is very difficult to measure the amount of profit that represents 'resource rents' – project capital costs are typically high, the production life of a typical project is long, and there is a lot of uncertainties during the life of a project.

Firstly, different projects will involve different risks, and therefore different levels of normal profits. Moreover, project supporters have no incentive to let the Government know what net returns from the project are comprised of 'normal profits' and what profits are comprised of 'resource rents'.

Secondly, a project may be comprised of a number of vertically integrated projects. Rent taxes, directed as they are at the net value of a resource after deducting all costs of extraction (including normal profits), need to be levied at the point of extraction. However, almost no resources are sold at the point of extraction, undertaking to various degrees some value adding processes prior to commercialisation. At an extreme, this may involve converting to liquid gas, or as feedstock into a vertically integrated gas fired power plant. Each of these downstream processes involves varying levels of risk, which makes attribution of rents to the resource difficult to do.

Finally, extraction costs also include exploration costs. If exploration costs are high (and exploration was undertaken efficiently), then the 'resource rent' may be illusory – it instead represents normal profits that accrue to exploration efforts.

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CHAPTER 4: EXPLORATION

Allocation of Exploration Licences

Currently in PNG, mineral exploration licenses are awarded on a 'first come, first served basis' with exploration license holders having the right to apply for a mining lease to develop any deposit they may have found.[12] Exploration licenses are presently issued for two years. They may be renewed for periods of two years indefinitely subject to meeting the regulatory requirements. There is provision for mandatory relinquishment of part of the license area (50 percent) at each renewal.

With the large upswing in metal prices in recent years, there has been a substantial increase in exploration license applications around the world and PNG is no exception. There are approximately 332 applications waiting to be processed. In addition, given that licences need renewing after every two (2) years, there are approximately 135 exploration licenses currently awaiting renewal[13].

This is over and above the more than 2,200 exploration licenses presently issued. This significant increase in license applications came with little increase in the number of staff in the Mineral Resources Authority (MRA) to process the applications, which has resulted in the amassing of applications and renewals. Application processing includes not only review of the technical and financial capabilities of the applicant but also a mining warden's hearing conducted within the area the subject of the application.

Once the backlog is cleared[14] the MRA will be faced with the parallel workload of monitoring compliance with the exploration work program on which licenses were issued. This particular task is critically important because there is a growing trend around the world for license applicants to obtain exploration licenses and 'land bank' them then doing little or no exploration work but offering the exploration rights, which are transferable after the initial two year term, to other interested parties for a fee to share or

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[12] The Department of Mineral Policy and Geohazard Management (DMPGM) is presently undertaking a substantial mineral policy review which may result in amendments to the *Mining Act 1992* and changes being made to license terms and conditions and licensing procedures. Thus reference is made to present arrangements.

[13] As of March 2013 (the time of the IMF visit to Port Moresby)

[14] at the time of IMF visit this was anticipated to take around 18 months.

take over the exploration license outright.

At present the large backlog of applications and renewals means that MRA is undertaking compliance checks on an ad hoc basis, or at the end of two years for when consideration of a license is made to renew. A computerised mining tenements (license) information and management system is proposed to be developed and installed under a World Bank funded project. It is anticipated that this project will be completed by the end of 2014, subject to testing and commissioning. This will enable MRA to process licenses much more efficiently and MRA considers that once the backlog is processed and the computerised tenements information and management system fully operational, it will be able to undertake compliance monitoring every 6-12 months instead of about every two (2) years as is the case now.

Once the large demand for license applications has been processed, there will be little new land available for new license applications, except for land being handed back at renewal, relinquished or surrendered.

At that time there may be more than one interested applicant and PNG may wish to reconsider how it goes about awarding licenses. The first come first served approach will reward the fastest applicant though not necessarily the best qualified applicant. Nor, as is relevant in the context of this Review, will it maximise the returns to PNG itself.

For petroleum prospecting licences, PNG has an 'open door' policy. This nominally involves a bidding process that accords with a 'work program bidding' auction model, however it is unclear whether in practice the bidding process is competitive and transparent. As a result, most of the country is also covered by land subject to petroleum prospecting licences.

One means of improving the allocation of exploration of licenses would be through a cash bidding process. Such a process could help the State collect resource rents without imposing extra taxation on normal profits or costs. This is because firms will, in a competitive market, bid up the price of exploration permits until the resource rent apparent at that point in the project cycle is included in the sale price. This will not capture all of the resource rent, however, because the resource rent is greatly discounted due to uncertainty at this early point of the project cycle.

If there was an inclination to move towards such an open bidding process then, given the large number of applications to be processed, consideration could be given to introducing a moratorium ('reservation' under the *Mining Act*) on the issue of new licenses and introducing competitive tendering for the remaining applications. This would require close consultation with industry and the need to promptly prepare the necessary legislative and regulatory changes, build up the capacity of regulatory agencies to undertake a tendering process and then offer land areas for bidding in a series of bidding rounds until all the land for which applications have been made are tendered and licensed. The regulatory agencies would then be able to tender land that is released at the time of a license renewal.

Ideally, the exploration right should be awarded to the highest bidder. Awarding the right to a company based on other criteria such as work program, technical and financial capabilities ('work program bidding') imposes additional processing and compliance burdens upon regulatory agency staff, and opens up the need for additional governance arrangements to ensure probity of the grant awarding process. This may be challenging in an environment where regulatory agencies' capacity is already stretched.

Furthermore, work program bidding potentially wastes resource rents when bidders over-bid work in order to win licences, or carry out their full work program even where initial work strongly indicates that further exploration work is fruitless.

If competitive tendering for exploration and prospecting licences were to be introduced, then further work will need to be undertaken to ensure that the design of the auction system maximises the return to the country.

Question 4.1 – do stakeholders consider that the current process of awarding exploration licenses in PNG is appropriate? Why or why not?

Question 4.2 – in principle, should PNG consider moving towards a competitive tendering process based upon cash bidding? If so, should this process be applied to outstanding applications, with a moratorium introduced for the issuing of new applications until such a process is put in place?

Double Deduction for Exploration Expenditure

In the early 2000s, to address the then low levels of exploration, PNG introduced a double deduction for exploration expenditure (see section 155N of the ITA 1959). As noted above, given the extensive coverage of PNG with exploration development licences, it appears that such an incentive is no longer required.

Question 4.3 – is the double deduction still required as an incentive to promote exploration, given the changes in PNG since it was first introduced?

Exploration Expenditure Deduction Restrictions

Under the tax ring fencing imposed in PNG, allowable exploration expenditure related to a license and incurred before the award of the development licence is only deductible from the income of that project. The deduction is a declining balance depreciation at 25 percent unless straight line depreciation over four (4) years is more favourable.

There is, however, a first limitation as the deduction for exploration cannot cause a tax loss. In addition, exploration costs incurred within a development licence after its award have to be considered as allowable capital expenditure and not as allowable exploration expenditure.

Exploration expenditure incurred in PNG but outside the project ring fence may be deducted from the income generated by a producing project, subject to another limitation. The allowable deduction cannot exceed 10 percent of the annual taxable income. The effect is to postpone the amortisation of exploration when a company has a large exploration budget in PNG.

In order to ensure that exploration is taxed as neutrally as possible, the 10 percent limit could be lifted.

Question 4.4 – should the 10 percent annual taxable income cap limitation on deducting exploration expenditure be removed?

CHAPTER 5: ALIGNING INCOME TAXES

Petroleum, Gas and Mining Income Tax Rates and Dividend Withholding Tax Rates

The income tax arrangements applying to petroleum, designated gas and mining projects differ, and the principal difference is in the income tax rates and the dividend withholding tax rates. There are also differences in the State's equity participation right and the application of additional profits tax. These are explained in Chapter 3, as they fall into the category of 'rent taxes'.

Petroleum projects are subject to income tax rates varying between 50 percent (old rate), 45 percent (standard rate) and 30 percent (incentive rate). However, profits from these projects are not subject to dividend withholding tax. Designated gas projects are subject to an income tax rate of 30 percent, with no dividend withholding tax. Mining projects are also subject to an income tax rate of 30 percent, but are also subject to a dividend withholding tax of 10 percent. This is broadly equivalent to a 37 percent tax rate with no withholding tax.

The rationale for the tax rates on mining projects were that they are consistent with a global norm for taxation of mining projects, and are also reasonably consistent with the standard income tax applying to other sectors of Papua New Guinea's economy – a 30 percent income tax rate with a dividend withholding tax rate of 17 percent (or 15 percent under Papua New Guinea's double tax agreements), broadly equivalent to a 41.9 (or 40.5) percent tax if no dividend withholding tax were applied.

However, with high metal prices, the income tax applicable to mining projects is no longer in itself likely to capture a fair share of resource rents for PNG. As outlined in Chapter 3 and further explored in the following Chapter, this could be addressed through the developed of an appropriate fiscal instrument to capture resource rents.

Question 5.1 – provided a suitable rent tax (see Chapter 6) is introduced for mining projects, should new mining projects continue to be subject to a 30 percent income tax rate with a dividend withholding tax rate of 10 percent?

The rationale for a high rate of tax on petroleum projects, apart from the incentive rate, is to try and capture rents that accrue to such projects due to the high price of oil that resulted from the restriction of supply by the Organisation of the Petroleum Exporting Countries (OPEC). The incentive rate was provided as an inducement for increased exploration in the early to mid-2000s, although as mentioned in Chapter 3 (Figure 5), the response to such inducement may have been limited because of a diminishing global pool of investment.

These high rates of tax on petroleum projects, however, act as an imposition of tax on normal profits. A rent tax, as discussed in Chapter 3, is a more efficient way of capturing resource rents accruing to petroleum projects.

Moving towards a company income tax regime that includes a dividend withholding tax also maximises the creditability of PNG taxes for an international investor in their home jurisdiction. This is because withholding taxes tend to be more creditable than underlying income taxes. If PNG taxes are creditable, then the investor's world-wide tax burden is reduced because a major part of PNG's tax burden falls on the investor's home jurisdiction.

Question 5.2 – provided a suitable rent tax is introduced for petroleum projects, should new petroleum projects be subject to a 30 percent income tax rate with a dividend withholding tax rate of 10 percent?

The rationale for the designated gas income tax arrangements was to induce the construction of the PNG LNG project, given the specific economics of that project.

The project involves extensive midstream (i.e. pipelines) and downstream (i.e. liquified natural gas plant) construction that did not previously exist in the country. These pipelines and the downstream processing plant have high capital costs and low operating costs. Consequently, building them involved unusually high construction risks when compared with other projects.

The successful construction of the midstream and downstream infrastructure could partially de-risk the commercialisation of other gas projects provided that there are third party access arrangements in place to allow third parties to commercialise gas reserves. Third party access arrangements could be implemented through the Independent Consumer Competition Commission. However, such arrangements must carefully balance the need for third party access, while ensuring that the arrangements are not sufficiently onerous so as to provide a disincentive for future gas projects.

> **Question 5.3** – what are stakeholders' views on ensuring that there are third party access arrangements over the PNG LNG and any new gas project midstream and downstream infrastructure? What issues might arise in introducing such arrangements?

By underpinning the economics of any new gas project through third party access to the PNG LNG midstream and downstream infrastructure (in effect, providing new projects with at least one viable option to commercialise the resource), there is arguably less need to ensure that gas projects receive fiscal terms that are more generous than mining or petroleum projects.

For new gas projects, PNG could consider ensuring that projects are segregated (as opposed to integrated) so that fiscal issues can be tailored to the supply chain, and to include terms and conditions for third party access in project documents, to help provide third party access to infrastructure. This should further de-risk projects that seek to commercialise PNG's gas reserves. Segregation should also assist in the application of any rent targeting fiscal instrument, as it should help prevent the shifting of capital costs into and revenues out of the rent tax ring fence.

Again, structuring PNG's income tax system to include a dividend withholding tax maximises the likelihood of the creditability of the country's income taxes.

> **Question 5.4** – provided that a suitable rent tax and third party access arrangements over midstream and downstream infrastructure are in place, should <u>new</u> gas projects be subject to a 30 percent income tax rate with a dividend withholding tax rate of 10 percent?

Aligning the income tax regime for petroleum and gas projects will greatly simplify the accounting of petroleum operations and the conversion of a field as a part of a petroleum project or gas project when the prescribed gas to oil ratio is exceeded. It will also help streamline the tax regime, as the same rate of income tax would apply to resource extraction and general (non-resource extraction) projects. This will help reduce the administrative burden faced by the Internal Revenue Commission. It will also simplify the income tax system, creating a better environment for potential investors.

Transfer of Interests

The income tax treatment of transfers of interests in mining and petroleum licenses and projects is unclear.

For the vendor it seems clear that any gain on the sale of the interest is not taxed, and if the vendor has any undeducted allowable capital expenditure (ACE) or allowable exploration expenditure (AEE) then these can be transferred to the buyer.[15]

The buyer, in the case of petroleum, can only claim the ACE and AEE transferred to them. However, for mining, it appears the full amount paid by the buyer can be treated as ACE (see ITA 1959 section 156B).[16]

The experience of other countries is that the non-taxation of these transfers can become a public and political issue due to the potential size of the transactions.

The possible acquisition of exploration licenses for speculation purposes also raises the question whether gains on these transactions should be taxed. These gains may be taxed in some cases as profit making transactions (section 47), but this provision depends on the intent of the taxpayer, which can be difficult to determine and is often subject to dispute. There is also a stamp duty on the transfer of interests which could be viewed as an indirect tax on the capital gain, although the tax is small (i.e. two percent).

The current tax treatment of transfers of mining interests is not symmetrical and is open to tax planning - that is, the gains are not taxed, but the full acquisition can be deducted as ACE. An appropriate approach in the absence of the taxing of the gain[17] would be to limit the deduction to the undeducted ACE and AEE. This should limit the tax planning opportunities and ensures that there is not an unnecessary deferral of revenue on the change of interests. It is also consistent with the tax treatment of the transfer of petroleum interests.

Question 5.5 – should the deduction of a buyer of a mining or petroleum interest be limited to the undeducted allowable capital expenditure and allowable exploration expenditure of the vendor?

[15] The transfer is achieved by the vendor and buyer giving the Commissioner General a notice under section 155L of the ITA 1959.

[16] This is not available for petroleum acquisitions.

[17] If Papua New Guinea decides to tax the gains on direct transfers of interest, it needs to ensure that it retains taxing rights under its double taxation agreements, including indirect transfers of value.

Part sale under non-cash farm in or private override royalty arrangements are particularly difficult due to their nature as a partial sale along with the difficulty in ascertaining the portion of the right sold. One possibility is to provide certainty by deeming one party (e.g. the buyer or the farmer) to be responsible for the entire taxation obligations related to the resource. However, in the absence of evidence that such arrangements are creating administrative or compliance concerns, no consultation question is being offered by this paper.

Mine Closure

At the end of the economic life of a mining or petroleum project, companies are obliged to incur large costs to 'decommission' the site. This can include removal of platforms and industrial structures, abandoning of wells, and site reclamation. Decommissioning costs can be significant, and because they are incurred at the end of operations there may not be sufficient income to cover the expenditure causing the contractor to incur a tax loss that cannot be used against other income.

The law was recently amended to provide relief if the taxpayer has multiple projects, by piercing the ring fence upon mine closure. However, this relief does not have value if the taxpayer has a single project.

To address the single project situation, a deduction could be allowed for a cash contribution to a decommissioning fund. The company contributes annually to a fund held in an interest-bearing escrow account under joint control with the government. Contributions to the fund are tax-deductible and any surplus accumulation in the fund at the end of the project, after deducting actual decommissioning expenditure, is returned to the company and taxed as income.

Question 5.6 –in addition to the piercing of the ring fence, should taxpayers be allowed to make contributions to a mine closure trust to bring forward deductions for decommissioning expenses into the income producing phase of a ring fenced project?

Gas Oil Ratio

At present there are differences in the way petroleum projects and designated gas projects are treated. The OGA and ITA 1959 provide for the possible conversion of a field which is part of a petroleum project to a designated gas project when the prescribed gas oil ratio condition is met. This potentially reduces the income tax rate applied to the taxable income of that field, when the applicable rate to the field under a petroleum project is not the incentive rate (i.e. 45 or 50 percent), although the project then becomes subject to the additional profits tax.

Gas reservoirs usually contain a range of hydrocarbons. They also produce 'liquids', such as condensates and other natural gas liquids, including liquefied petroleum gas.[18] These high-value products sell directly from the field site at prices close to oil.[19] The presence of large quantities of liquids in the gas ('wet' gas instead of 'dry' gas) can significantly improve gas project economics. The recovery of the liquids contained in a wet gas reservoir is often maximised by 'cycling' (reinjecting) the produced gas during the first years of production in order to maintain the reservoir pressure while selling the condensates, and then later sell the gas.

If the gas oil ratio is calculated on the basis of what is extracted notwithstanding the cycling process (as it appears under subsection 155(1) of the ITA 1959), the field is more likely to be considered a gas project, consistent with the characteristics of the in-reservoir resource. However, if the gas oil ratio is calculated on the basis of what is sold, then the field (initially) is more likely to be considered an oil project consistent with what is marketed from the project.

Alignment of the income tax regimes should address this issue. However, in the meantime it may make more sense to tax a project consistent with what it produces, given the rationale of gas treatment is in recognition of the high capital costs to commercialise the resource rather than the nature of the in-reservoir resource.

Question 5.7 – should the application of the gas oil ratio test be measured on the basis of resource extracted to product marketed? What issues might arise with such an approach?

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[18] Condensate is hydrocarbons that 'condense' to liquid when brought to the surface (consisting of pentane and longer chain hydrocarbon molecules). Liquefied petroleum gas (LPG) is propane and butane obtained from gas after a special processing. Natural Gas Liquids comprises condensates and LPGs.

[19] Additional liquids may be extracted at the liquefied natural gas plant.

Hedging Gains/Losses

Gains and losses on hedging transactions can cause significant difficulties for the taxation of the mining and petroleum sectors. Hedging transactions tend to be very complex and often involve multiple offshore entities. These transactions can give rise to significant losses (and also significant profits), which may impact on the tax collected from mining and petroleum companies. One approach of avoiding this is to treat hedging separately and taxing it under standard income tax.

Provided that there is certainty to project companies, they can enter into arrangements to use hedging to control risk in a tax neutral manner.

Consultation Question 5.8 – should separable hedging gains and losses be taxed outside of the project ring fence, under the standard income tax regime?

Partial Year Depreciation

Mining companies can depreciate using a 25 percent declining balance method (sections 73-78 of the ITA 1959). Under these provisions, a company may take a full year's depreciation deduction in the first calendar year of commercial production, even when commercial production was for a small part of that year.

This results in differing tax treatment according to what time of the year a project commences. To address this, the depreciation rules could be modified to ensure that depreciation in the first year of commercial production of a project is pro-rated.

Question 5.9 – should depreciation deductions be pro-rated in the first year of production?

Other Aligning Changes

There are a range of other differences between the treatment of designated gas, petroleum and mining projects. For example, on cessation or abandonment of designated gas[20] or petroleum[21] projects, the Commissioner General has the discretion to allocate undeducted allowable capital expenditure to other projects or allow them to be carried forward for 20 years of cessation or abandonment. Such a discretion does not exist for mining projects.

Submissions could consider whether there are other aspects of the income tax system that could be aligned between mining, designated gas and petroleum projects, so as to minimise complexity and improve compliance and administration of the tax system. Such changes would continue to reduce the burden on an already stretched Internal Revenue Commission.

Question 5.10 – what other changes to Division 10 of the *Income Tax Act 1959* could made to align the income tax treatment of designated gas, petroleum, and mining projects?

[20] Subsection 158D(3) ITA 1959.

[21] Subsection 157C(3) ITA 1959.

CHAPTER 6: DESIGN OF A RESOURCE RENT TAX

Introduction

In this Chapter, the design of a fiscal instrument that specifically targets resource rents is considered. As discussed earlier, such a fiscal instrument could ensure that PNG receives its fair share of resource rents, given that these rents represent the value of the resource owned by PNG.

Such a fiscal instrument will also improve the progressivity of the fiscal regime, thereby reducing political pressure to alter the fiscal regime to collect more taxes when global commodity prices are high. As well, such a fiscal instrument will also reduce the tax burden when global commodity prices are low to attract (scarce) investment capital. This in turn will improve the stability of the fiscal regime, something highly sought after by mining and petroleum companies and which improves the attractiveness of PNG as an investment destination.

The development of a fiscal instrument which targets resource rents will also reduce the risk that a project investor will not be able to make a normal return on its investment. Resource rent targeting fiscal instruments reduce taxation if commodity prices are less than what an investor expected. This in turn reduces the downside risk of an investment in PNG at the final investment decision stage. This aspect of resource rent targeting fiscal instruments also ensures that projects do not close early and leave resource rents in the field, uncommercialised.

Such fiscal instruments, due to their nature as progressive fiscal instruments, also increase the volatility in revenue collections. PNG is in the process of implementing a Sovereign Wealth Fund whose principal role will be to stabilise the flow of mining and petroleum revenues into the budget. It should therefore be acknowledged that the effectiveness of the resource rent targeting fiscal instruments considered in here is linked with the successful implementation of the Sovereign Wealth Fund.

PNG already has two (2) fiscal instruments that target resource rents – the State's equity participation right, and the additional profits tax applicable to designated gas projects.

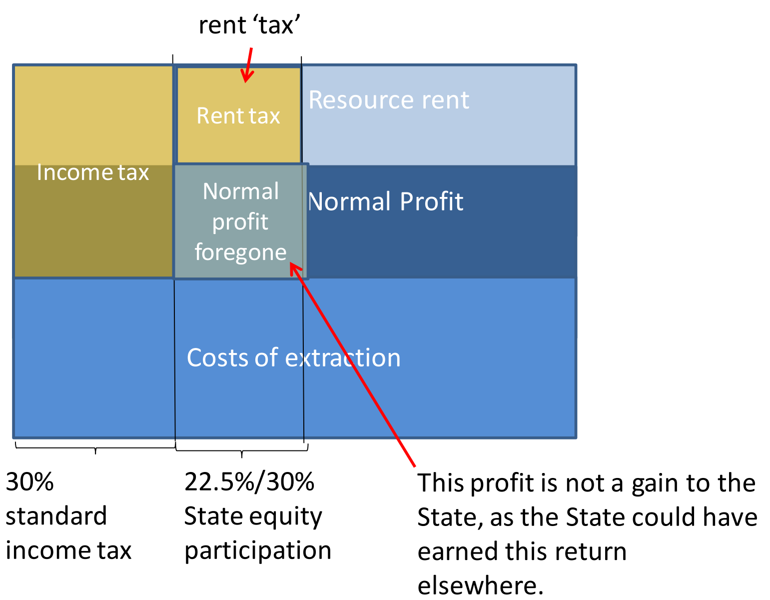
State's Equity Participation Right

The State has the right, but not obligation, to acquire a share of designated gas, petroleum or mining projects. The State can acquire up to 22.5 percent of a designated gas or petroleum project, and up to 30 percent of a mining project, at par value, or 'sunk cost'. This means the State can acquire a share in a project by paying its share of the project's historic cost (including exploration cost), and an ongoing share of future costs.

In return, the State can receive a share of the profits of the project, paid as dividends, in accordance with its right as a shareholder. However, the State is not better off under this arrangement by the amount of the dividends, because the State would need to finance its share of the project. As funds used to finance its share of the project could have been used to generate returns in an alternative project, the State is only better off by the amount of the dividends that exceeds what the State could have obtained in an alternative investment. This excess is roughly a share of the resource rent equivalent to the State's share in the project.

Using similar Figures as those used in Chapter 3, this can be shown in Figure 8.

Figure 8. How State equity participation at sunk cost operates like a rent tax



However, many projects do not include resource rents that should be targeted. This is because sunk costs appropriately include exploration costs, and at least some, and in some cases all and more, of the 'rents' actually represent normal profits accruing to exploration. These rents are known in the literature as 'quasi-rents'.

As a simple example, a company may have incurred K100 million in exploration costs to find a mineral resource. Commercialising this mineral resource will generate a future stream of net revenue worth K140 million if developed, which will cost K45 million. For the company, the decision would be made to proceed, as the net revenue (worth K140 million) is worth far more than development costs (K45 million).

For the State, exercising the option (to acquire, say, 30 percent of the project) would require it (the State) to contribute K43.5 million (30 percent of the aggregate of sunk exploration costs and development costs, or K145 million) in order to obtain the right to acquire net revenue worth K42 million (30 percent of the net revenue of K140 million) – a loss of K1.5 million, together with the opportunity cost of forgone profit on an alternative investment.

At times, the State's decision as to whether or not to take equity in a project is a fine balance, requiring great judgment (and therefore capability and resources) necessary to determine whether taking equity will enable the State to acquire a portion of the resource rent, or represents a transfer in value to the project owner.

This value of judgment is exacerbated by the asymmetry of information – a project with poor economics may have an incentive to invite the State's participation hence present the project optimistically and attractively to the State. A project with superior economics may have the incentive to deter State participation and do the opposite. The need for considered judgment may cause delays for project supporters while the State considers whether to take equity in a project or not.

Furthermore, a project's economics based on existing information might suggest that a project is unattractive to the State, however by not exercising the option, the State foregoes the right to any future resource rents associated with the development license if the resource proves larger after more information is obtained.

Even if a project's economics justifies the State taking equity in order to obtain a share of the resource rent, the project supporter may try to have the State invest in an integrated project, including within the project ring fence midstream and downstream processing infrastructure. This could greatly increase the funding required to take equity in the project in order to capture the same amount of rent, thereby lowering State equity rates of return (and increasing the project supporter's rate of return on their capital).

Targeting resource rents through State equity participation also eliminates any possibility that the rent 'tax' will be creditable in a foreign investor's home jurisdiction. As the 'tax' is legally in the form of a dividend to the State, no credit is likely to be available to the investor in their home jurisdiction.

The State's equity participation right also creates significant governance issues vis-à-vis;

- First, there is an implicit budget subsidy, whereby the State nominee has first call over revenues to support State participation (or other activities of the nominee, giving rise to concerns that expenditure is undertaken off budget)[22] over other budget priorities.

- Second, the State participation in projects reduces clarity between the commercial and non-commercial role of the State. There is often a temptation to grant concessions to a project in which the State has an equity interest. Such a result is of little benefit to the State, as the State must pay the whole of a concession but receives only its share of the profits. However, institutional weaknesses in governance arrangements may allow this temptation to be acted upon.

- Finally, there is commonly a disconnect between the financing of the State's equity participation, and the dividends that flow from the State's equity - in many cases, the dividends are received by a State nominee that has little responsibility to meet the loan obligations associated with financing. As a result, the State equity participation creates artificial revenue streams (dividends that should otherwise be used to repay debt used to finance the equity participation) that attract competition to obtain control of those streams.

[22] Full adoption of the *Government Finance Statistics Manual 2001* to appropriately categorise State nominees in the Government's fiscal reporting can help address this concern.

An alternative that could address many of these concerns is to impose an obligation on projects to provide a free carried interest, whereby the State borrows from the project, and the loan is repaid by forgone rights to dividends and profits from the project. This alternative however is arguably not as effective as a rent tax, as the two (2) achieve similar outcomes except that dividends paid to the State are not available as tax credits to the investor, and some governance concerns remain.

At the same time, projects sometimes consider that State equity participation in their project helps them overcome administrative and compliance barriers due to the alignment of interests that occur. However, this only provides a justification for State (or landowner) equity - it does not necessarily provide a justification for designing a resource rent targeting instrument in the form of State equity. If the benefits that flow from State equity exists, projects are free to sell equity to the State on whatever terms they see fit.

On balance, there appears to be better merit in implementing a resource rent targeting fiscal instrument that is self-executing (saving scarce State agency capacity and resources) and which is stable and transparent to prospective investors, such as a rent tax.

Question 6.1 – do stakeholders agree with the pros and cons of state equity participation as described? What other factors might be relevant when considering the benefits of State participation?

Question 6.2 – what are stakeholders' views on the value of the State having a carried interest in a project?

Question 6.3 – as a general principle, do stakeholders agree that the State should focus on ensuring it collects a proportion of any resource rent from new projects through an appropriately framed fiscal instrument rather than through State participation?

Additional Profits Tax

As discussed in Chapter 1, PNG currently imposes a two-tiered additional profits tax on designated gas projects. PNG has applied some form of additional profits tax to mining and petroleum project in the past. With the exception of an additional profits tax in the form negotiated for Bougainville Copper Limited, no additional profits tax has been paid by any petroleum or mining company. An implicit additional profits tax was paid by the Kutubu oil project partners because the State's accumulated liability on its carried interest was paid from the State's share of oil.

The lack of revenue collected by the additional profits tax does not mean that the design of the tax itself is necessarily at fault. Instead, the lack of collection of additional profits tax in the past appears to have resulted from the previously high rate of income tax itself, and the very high uplift rate that was originally set at a fixed rate in a high inflationary environment.

As mentioned previously, the design of the additional profits tax closely replicates a State carried equity participation, with the tax rate being equal to the State's 'share'. However there is one key difference. If project net revenue fails to return the State's investment,[23] then the State is not obliged to pay[24] its share of the shortfall. In the existing State equity participation arrangements, if project net revenue fails to repay the State's investment, then the State bears that cost (i.e. there is recourse to the State as investor). If the existing State equity financing arrangements are analogous to equity financing, then an additional profit tax is analogous to project financing with limited recourse to the investor.

To ensure equivalence of the additional profits tax with State equity in light of this limited recourse, the net cash outflows incurred by the project has to be indexed (or 'uplifted') by an optimal amount to cover normal profits, including a premium for taking on risk that the State is not bearing due to the 'limited recourse'. If this optimal uplift is applied, then the additional profits tax should only collect resource rents (Figure 9).

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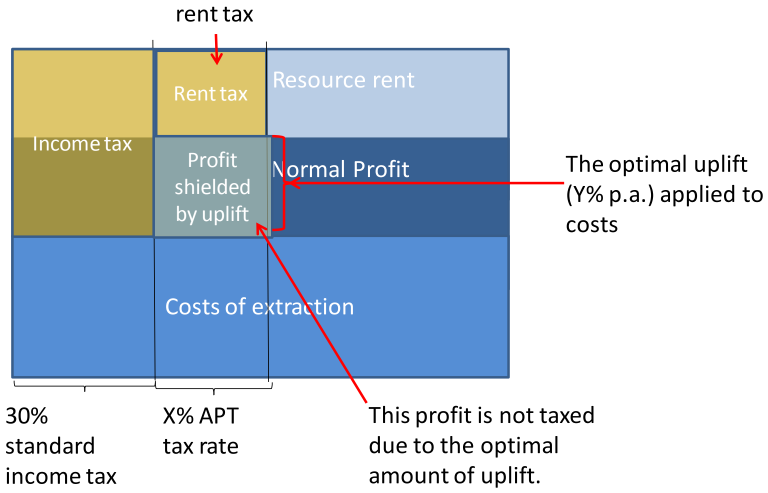
[23] Including an estimate of normal profit.

[24] Or forgo, in the case of normal profit.

Figure 9. How State equity participation at sunk cost operates like a rent tax



The optimal uplift rate however is difficult to estimate. Resource companies have no incentive to disclose levels of resource rents, and the level of resource rents vary with changes in the global economy, which are inevitable in the long production life of a typical project. For example, an uplift rate could be set too high due to unexpected lower inflation. Although inflation could be addressed through using a floating rate, other changes (e.g. volatile commodity prices) cannot.

Moreover, the optimal uplift rate varies between resource projects,[25] and there is no universal optimal uplift rate for all projects.[26]

If the uplift rate is set too low for a project, then the additional profits tax will tax normal profits, and create a disincentive to invest. If an uplift rate is set too high for a project, then targeted resource rents will not be collected. In addition, projects can use techniques such as project integration to move capital intensive assets (e.g. pipelines, liquefied natural gas plant) within the additional profits tax ring fence to take further advantage of a too high uplift rate.

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[25] The riskiness of the project is the relevant risk, due to project ring fencing. If there were no ring fencing, then the riskiness of the individual firm would be the relevant consideration.

[26] If losses were credibly refunded by the State, the rent tax would be similar to the State's current equity arrangements. That is, the optimal uplift rate would no longer be that relating to project risks, but instead associated with investing in the State's issued bonds. Accordingly, the optimal uplift rate would be the State's borrowing rate.

It should be noted that other forms of tax can easily be redesigned to approximate an additional profits tax.[27] For example, an ad valorem royalty imposed on the wellhead or mine gate value of a resource, where the 'netback' used to determine the value of the resource takes into account both operating and capital costs with depreciation and an uplift rate for the capital costs, is very similar to a rent tax. However, the difficult issue of the optimal uplift implicit in the depreciation and uplift rates for capital costs remains.

A criticism often levelled at resource rent taxes designed around a rate of return, such as the additional profits tax, is that the pattern of tax collection is at the end of the project (i.e. back end loaded). This can create political pressure to change a tax in the early stage of a project when the project is recovering its investment, and the perception of low taxation arises due to no tax being collected. This is an important design criterion if a fiscal package is to remain stable over the volatile commodity price cycle.

However, a rent tax can be modified to bring forward the collection of revenues, through delaying the recognition of expenses or advancing recognition of revenue, provided that uplifts are applied and the bring forward is not so extreme to increase the risk of unused capital deductions or credits for advanced payment of income. That is, the rent tax can be designed to borrow 'future taxes' to pay for current taxes.

One approach to the uncertainty inherent in determining the optimal uplift rate is to use two tiers – a lower uplift rate associated with a lower tax rate to reduce the possible tax impost on normal profits, and a higher uplift rate associated with a higher tax rate to target what is more likely to be resource rents.

However, given the fundamental administration and compliance difficulties associated with a resource rent tax that involves an uplift, a simpler tax that approximates a rate of return based additional profits tax may be preferable, particularly given the other demands on the Internal Revenue Commission.

The following sections include a discussion on possible fiscal instruments that could be used to approximate a pure resource rent tax.

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[27] As noted previously in this chapter, a State carried interest equity right can also be designed to approximate an additional profits tax, with the interest rate on the implicit loan being the uplift rate. The difficulty in designing this right is to set this interest rate.

R-factor

An R-factor tax uses the ratio (hence 'R') of cumulative actual company revenues after income tax from the start of the project to the cumulative costs or capital expenditures at the date of the additional profits tax calculation. The ratio reaches 1.00 when cumulative net revenues equal cumulative costs and will increase throughout the life of a project. A three or more tier scheme might be used.

Since the R-factor tax, unlike the additional profits tax, ignores the time value of money, it is by design less efficient than the additional profits tax. In particular, the R-factor tax imposes a greater tax burden on short life projects than longer life projects. This makes selection of the ratios at which the R-factor applies or escalates difficult, if the aim is to target resource rents.

Nonetheless, the R-factor tax is a relatively common approach, with it becoming increasingly common around the world in the petroleum and gas sector (to date, no mining regime has adopted the R-factor tax). Its mechanism is simpler, and more easily understood than an additional profits tax that uses a rate of return methodology.

Sliding Royalty

Some countries have introduced sliding scale royalties as a rent collection instrument. This involves linking the royalty rate to the mineral price or the mining company's profitability. In the past five years a small number of countries (such as Chile, Peru, South Africa, and Mongolia) have introduced sliding-scale royalties linked to profitability or prices, with the highest rate (for Chile) being capped at 14 percent.

However, in PNG, this may result in friction between the government and the present recipients of royalties (namely, landowners and sub-national governments) as to how any increase in royalties should be shared between the State and these parties.

Income Tax Surcharge

An alternative design for collecting resource rents is an income tax surcharge, such as that used in the United Kingdom. This method of collecting rents is entirely based on the income tax system, and does not involve any uplift rate. Yet, it does not penalise short lived projects in the way that the R-factor tax does.

Under this method, a company's income is taxed under a surcharge. To help ensure that normal profits are not taxed, the company is given an immediate write off for all capital and any loss is carried forward to be set off against the income tax surcharge tax base. To help ensure that interest deductions are not manipulated to transfer profits outside the project ring fence, deductions for financing are not allowed. This disallowance can greatly increase the effective average rate of tax on profits; this is accommodated through the choice of the income tax surcharge rate.

Figure 10 sets out a method statement to calculate the income tax surcharge. It does not use any other tax characteristics other than those already collected by the existing income tax system. The similarity of the tax to the existing income tax system maximises the likelihood of creditability of the tax, and reduces the administrative and compliance burden of the Internal Revenue Commission and taxpayers. It also is easier to understand for the citizens of PNG, and addresses many of the governance concerns of State equity by ensuring that revenue flows are directed into the consolidated revenue fund (or a fully budget integrated Sovereign Wealth Fund) and managed under the usual budget process.

Figure 10. Income tax surcharge method statement

Step 1. Calculate the project's taxable income for the period.

Step 2. Addback carried forward losses applied.

Step 3. Addback depreciation deductions.

Step 4. Addback interest and financing deductions.

Step 5. Deduct any capital expenditure incurred in the period.

Step 6. Deduct any income tax paid in the period.

Step 7. If the result is negative (ie. a surcharge loss), this amount is carried forward to be set off against surcharge gains of future income years.

Step 8. If the result is positive (ie. a surcharge gain), then apply any available carried forward surcharge losses.

Step 9. If any positive amount remains after Step 9, then the surcharge rate is applied to the surcharge gain.

The simplicity of the tax, along with the simplicity associated with alignment of the company tax regime, may be particularly attractive to PNG given how stretched the resources are within the Internal Revenue Commission. Ideally, the tax system should make things easier for the tax administration, to enable them to perform their job according to the expectations set of them.

If an income tax surcharge model were to be adopted, the tax rate would need to be set so that the income tax surcharges collected are sufficient to replace the rents that would otherwise have been collected under the State's equity participation right and the additional profits tax.[28] This provides credibility that leads to improved fiscal stability into the future.

Question 6.4 – what are stakeholders' views on the various fiscal instruments discussed as a means of capturing resource rents? Which model might be most appropriate in PNG's context and why? Should consideration be given to extending an amended Additional Profits Tax across the various sectors?

Landowner Equity Participation Right

Currently, the State is required to grant free equity in resource projects to landowners from the area in which a project is located where it takes an equity participation interest. The landowners' share in projects is two percent for petroleum projects and five percent for mining projects, free carried by the State, and is controlled by a State nominee company managed by the Mineral Resources Development Corporation Ltd.

[28] This level of tax should also substantially exceed the additional profits tax currently applied to designated gas projects. In the event that the income tax surcharge or other new resource rent tax imposes less tax than the existing additional profits tax, the State could be exposed to significant costs due to 'most favoured nation' clauses contained in a project agreement that the State previously entered into. To prevent this, it may be necessary to continue the application of the existing additional profits tax regime to designated gas projects, but have any tax collected fully credited against any income tax surcharge.

If the State's equity participation right were removed as a part of any fiscal regime redesign this would potentially reduce affected landowners' equity. To ensure that they are not made worse off by the changes, the State could provide compensation funded by a share of taxes collected under the income tax surcharge applicable to the relevant project under a pre-set funding formula.[29]

Nonetheless, landowners may feel that they should have the opportunity to take an ownership interest in a project on their land. Although it would be expected that a project developer would consider entering into negotiations with landowners to provide landowners with the opportunity to acquire an interest in the project in view of the possible mutual benefits of doing so, there may be value in formalising this process in the relevant legislation.

Question 6.5 – should affected landowners be given the right, but not obligation, to acquire 20 percent of a project on commercial terms, to be exercised on or before the grant of the relevant development licence?

It should be noted that no government (national, provincial or local) should be obliged to assist the landowners in exercising this option, whether by way of negotiation, provision of finance or otherwise.

[29]As this is not strictly a matter of taxation, rather of inter-government fiscal equity, the Committee does not make any specific comment on this.

CHAPTER 7: ROYALTY AND DEVELOPMENT LEVY

Currently, all projects pay royalties at the rate of two percent. This is payable to affected landowners, local and provincial governments.

For mining projects, it is calculated based upon free on board sales. In addition, mining companies pay an additional levy of 0.25 percent to the Mineral Resources Authority.

For petroleum and gas projects, the levy is calculated based upon wellhead value. New designated gas and petroleum projects also pay a development levy of two percent, payable to the provincial government in which a project is located. However the royalty is creditable against income taxes (i.e. the royalty acts as a revenue sharing instrument between the National Government and provincial, local level government and affected landowners).

The result is that a resource project's overall royalty rate, apart from the Mineral Resources Authority levy, is two percent. This is low by international standards.

Notwithstanding that the royalty rate is low, as royalties can act to distort investment decisions, consideration could be given to maintain current royalty rates and instead rely on the development of an appropriate resource rent tax to take into account the relatively light royalty burden that is being imposed.

Question 7.1 – do stakeholders agree that royalty rates should be maintained, with a focus instead on developing an appropriately framed resource rent tax?

One area where reform might be considered in the context of new petroleum and gas licenses is the point at which the royalty is determined. Notably, a field gate value basis royalty determination could be used instead of a wellhead one (which is the current situation). The wellhead basis for determining the royalty and the development levy could be replaced as the deductions of the costs between the wellhead and the field gate remain a quite complex, time consuming and controversial issue.[30] The field gate means the fiscal point at the outlet of the field storage before entering the transportation

[30] For example, in offshore the allocation of costs before and after the wellhead is quite complex. Many countries have abandoned the wellhead basis for a field gate, point of export or similar basis.

system (or the point of export for an offshore field), as defined and agreed when the field development plan is approved.

Question 7.2 – for new petroleum and gas licences, should a field gate value basis royalty determination should be used instead of a wellhead one?

CHAPTER 8: TAX INCENTIVES

Many countries offer tax incentives to attract new investment and encourage growth both in relation to their extractive sectors and more broadly. The justifications for incentives include:

- Encouraging the production or consumption of a good that produces benefits that the private market does not fully take into account (i.e. positive externalities).

- Making a country competitive with its neighbours and hence more attractive for foreign direct investment.

- They are necessary to offset high non-tax production costs in a country.

Despite these justifications, there are a number of concerns with incentives, especially those that take the form of tax holidays. These concerns are:

- Tax incentives involve a loss of current and future revenue. If a revenue target is to be achieved, taxes must be higher in other activities, which harms economic efficiency and compliance, and causes inequities.

- Tax incentives by their nature are inequitable and inefficient as they create different tax treatments between and within sectors and this leads to distorted resource allocations. Another danger in providing incentives for only a small portion of the economy is that it encourages 'exemption creep' - that is, providing an exemption to one sector or activity creates pressure from other similar 'worthy' taxpayers for the same exemption.

- Tax incentives create opportunities for tax abuse and corruption. An example of such abuse includes transfer pricing between related parties to ensure profits are made in exempt activities and deductions in taxable activities.

- Tax incentives complicate tax administration and compliance. These complications often arise because of the need to monitor the incentives due to concerns with abuse. The administration and compliance difficulties are especially likely in countries where the tax administration is weak.

- Tax incentives, especially tax holidays, tend to attract footloose firms that leave as soon as the incentive expires, without lasting employment effects.

- Tax incentives may be redundant as they do not lead to a change in the intended behaviour, as the incentive simply benefits those firms that are, or were intending, to undertake the sought behaviour.

- Taxes are not the most important factor in investment decisions. Studies suggests that other factors - such as market size, labour costs, infrastructure, and a stable economic and political environment - are likely to be equally or more important.

- The benefits of tax incentives may be reversed if a foreign investor is from a country that taxes its residents on a worldwide basis (e.g. the United States). In those cases, foreign profits repatriated to the country of residence will be taxed at the residence country rate with a credit given for any tax paid in the source country. Therefore, the effect of a tax incentive is to transfer revenue to the residence country.

- Tax holidays are inefficient in promoting investment in new enterprises, which are often unprofitable in the early years and unlikely to benefit from the incentive.

In light of these concerns, income tax holidays in PNG should be avoided, especially in the extractive industries. Few countries provide tax holidays to mining and petroleum projects because they want to ensure the state receives a fair share from the resources. A tax holiday defeats this purpose, as does reductions in main fiscal rates.

If the authorities want to provide tax incentives, a better approach may be to provide accelerated depreciation or investment tax credits, as PNG already does in certain cases. These incentives reward the actual act of investment and can be targeted at investment in the preferred activities or locations. The accelerated depreciation provided to the mining and petroleum sector seems reasonable, although some of the expenditure uplifts may benefit from review.

It is noteworthy that from 2013 to 2014, the gross domestic product contribution of the mining sector is expected to rise, whereas the share of the mining sector's contribution to revenue is expected to fall. In large part this is likely to be a result from the tax holiday granted to the Ramu Nickel mine, which is projected to move to full production in 2014 without paying any income tax.

Question 8.1 – what are stakeholder's views on the provision of tax incentives for the mining and petroleum sector? Should special reductions in main fiscal rates not be granted to any new mining or petroleum projects?

Infrastructure Tax Credits

The infrastructure scheme is aimed at encouraging operators in resource projects, primary production and tourism to spend money on infrastructure in the area in which the resource project is located (or other areas). Approved projects generally take the form of public welfare type projects such as schools, aid posts, hospitals, roads or other capital assets.

Money spent on such projects is treated as a tax credit – tax payable is reduced by the expenditure incurred on such projects – so there is no cost to the company actually spending the money.

In general, the annual cap that may be spent on such projects is 0.75 percent of assessable income.[31] Any unutilised credits may be carried forward for a period of two years. In other words, if less than 0.75 percent of assessable income is spent in one year, the remaining unused 'cap' may be used up in the following two years, in addition to the normal cap.

If a company overspends in one year, the extra amount spent may be rolled forward indefinitely. The amount of tax credit claimable in any one year is limited to the amount of tax payable by the taxpayer.

Although the scheme has merit in that a resource project is often a more efficient and effective provider of infrastructure in the communities in which they operate, it is often unclear to communities that the National Government is actually providing the infrastructure in the form of revenue foregone. The annual cap is set at a level that reflects the National Government bearing the total cost of the expenditure.

There are parallels between infrastructure spending by resource projects and the treatment of donations to registered charities by individuals. In both cases, the taxpayer is providing socially desirable funding allocations. However, unlike an individual who is free to determine to which charity a donation can be made, a resource company is obliged to seek approval from Government.

[31] Very generous infrastructure tax credits were extended to projects approved by National Executive Council prior to 19 November 2013 under a recent amendment to section 219C ITA 1959.

At the same time, the nature of the infrastructure provided gives the resource company greater private benefits in the form of community goodwill.

Taking into account both the expenditure restrictions as well as the greater private benefit of infrastructure spending compared with donations, the infrastructure credit could be replaced with a 150 percent infrastructure deduction, deductible for the purposes of both the income tax.

This could allow PNG to increase the annual cap to two percent of assessable income, thereby potentially resulting in greater community infrastructure provision at a similar cost to the revenue.

Question 8.2 – should the infrastructure credit scheme be replaced with an infrastructure 150 percent deduction scheme, with an increase in the annual cap to two percent of assessable income?

Chapter 9: International Aspects of the Mining and Petroleum Fiscal Regime

Transfer Pricing and Thin Capitalisation

PNG has transfer pricing rules and thin capitalisation rules applying to the extractive industries. The law includes rules to ensure that all transactions are at arm's length so as to prevent abusive transfer pricing, such as into and out of any income tax surcharge ring fence. Guidelines for applying the arm's length rule, based on the OECD's transfer pricing guidelines, have been released. To prevent thin capitalisation, a debt to equity limit of 3:1 is applied to mining and petroleum projects (for other sectors the limit is 2:1), with a deduction being denied for any excess interest.[32] The Commissioner General can also deny a deduction for interest on non-arm's length loans where the interest rate is not at a market rate.

Countries globally have been reducing their debt to equity ratios for thin-capitalization purposes to more closely reflect general commercial levels and reduce scope for profit shifting. While many countries have formed the view that debt to equity ratios of 3:1 are overly generous in any economic context, changes in corporate leveraging following the global financial crisis has brought this into sharper focus. New Zealand and Australia are two regional countries that have acted recently to reduce debt to equity ratios for thin-capitalization purposes. New Zealand has reduced the ratio for inbound investment to 1.5:1. Australia is in the process of reducing its ratio to 2:1, including for the mining, petroleum and gas sectors.

Question 9.1(a) – should PNG retain the thin capitalisation debt to equity limit applying to mining and petroleum projects when reductions are occurring in neighbouring jurisdictions?

Question 9.1(b) - Would 2:1 or 1.5:1 be more representative of commercial gearing levels in PNG's Mining, petroleum and gas sectors?

[32] Generally, the company holding an interest in a petroleum agreement has low equity, being an ad hoc affiliate of a parent company. Therefore the concept of 'debt to equity' is not directly applicable in upstream projects. The limitation on interest in such a case is expressed in relation to the total development capital costs, where only a maximum proportion (such as a 3:1 ratio) could be financed by debt. By contrast, exploration cost should be financed by equity, not bearing interest.

Ultimately it is critical that PNG's transfer pricing and thin capitalisation rules are effectively enforce, particularly in relation to mining and petroleum companies. As discussed in the following Chapter, the limited capacity of the IRC to enforce these rules could pose a significant risk to government revenues.

Double Taxation Agreements

Papua New Guinea has nine double tax agreements (DTAs). DTAs assist in determining the taxing rights of the source country as well as avoiding double taxation, and can be a source of certainty in taxation arrangements for foreign investors seeking to invest in another country. Whilst this paper does not examine DTA negotiation policy in detail, it is worth considering aspects of DTAs that have a particular bearing on the mining and petroleum sectors.

The current DTAs contain special provisions relating to the resources sector, but future DTAs should ensure the definition of 'permanent establishment' includes exploration. The current DTAs include specific provisions for the resources sector, such as the inclusion of additional profits tax and income tax surcharges as a tax subject to the agreement, which further ensures that a foreign tax credit (if available) can be obtained by the company in its country of residence.

While the definition of 'permanent establishment' of a foreign taxpayer includes 'a mine, gas or oil well, a quarry, or any other place of extraction of natural resources', the tax treatment of exploration could be clarified. The definition could be made clearer by specifically mentioning activities for the exploration and exploitation of natural resources. This will ensure PNG preserves its source taxing rights on income from the exploration, or exploitation, of natural resources.

In negotiating DTAs PNG should seek to preserve its right to extract reasonable withholding taxes. There has been a trend to lower withholding tax rates, even to zero in some DTAs. This arrangement is beneficial for both negotiating countries where there is a significant flow of income each way. For many developing countries, the flow of income is usually from the developing (source) country to the developed (residence) country, so that low withholding tax rates are beneficial to the developed country, but are of little benefit to the developing country.

In effect, the developing (or source) country is giving up revenue on source income for little benefit in return. PNG has a sound DTA negotiating policy with DTAs generally applying the same withholding tax rates as are set out under the PNG law. These withholding rates are reasonable, therefore, PNG should continue to resist lower rates in DTAs, but it should ensure that the DTAs provide for crediting of withholding taxes in both countries.

CHAPTER 10: OTHER ISSUES

Tax Administration

The possible changes in this paper could simplify the fiscal regime for new projects, reducing the complexity of tax administration thereby freeing State agency resources. However, the tax take that will be realised in practice depends not only on the design of the fiscal regime but also on the effectiveness of the tax administration. The Internal Revenue Commission (IRC) is responsible for administration of the ITA 1959, the Mineral Resources Authority (MRA) is responsible for collection of mineral royalties, the Department of Petroleum and Energy for collection of oil and gas royalties and the PNG Customs Services for collection of import duties.

The IRC have only undertaken limited work to ensure mining and petroleum companies are complying with their tax obligations. To date there have been little, if any, audits of the operating oil, gas or mining taxpayers.

There is an urgent need to undertake audits of mining and petroleum companies as well as subcontractors working with those companies. Regular auditing of these companies during the exploration, development and production stages is critical to ensure the correct revenues are being paid. These companies are one of the most significant sources of revenue for PNG and therefore need to be closely monitored, especially given (i) the size of the present oil, gas and mining operations, (ii) the extremely rapid growth of oil, gas and mining investment (over US$20 billion expected in 2012 and 2013), and (iii) the potential for exploitation of intangible costs.

The importance of IRC being adequately resourced and skilled to do this work cannot be over emphasised. The IRC has advised that it has funding for 580 positions, but has around 200 positions still vacant, while a recent review by the US Treasury suggested that to be fully effective the IRC should have an establishment of about one thousand (1,000) positions. The IRC has an active recruitment campaign but finds it difficult to source and retain appropriately skilled staff and the necessary levels of competencies. It is important that these positions be filled with the required people.

There are a number of steps that can be taken now to begin to monitor the sectors. For example, for oil and gas companies the IRC could undertake annual cost audits with information that should already be provided to Department of Petroleum and Energy and the state owned enterprises that hold equity interests (e.g. Petromin). One approach would be for the IRC to have a designated team focusing on 'individual costs' of oil and gas taxpayers with the State owned enterprises responsible for auditing the 'joint costs' in accordance with the joint operating agreements. For contractors, the companies should have data on payments to those contractors as well as tax paid. A first step could be to focus on the largest contractors.

The increased enforcement should also be accompanied by adequate dispute mechanisms, in particular ensuring a person is appointed for the Review Tribunal. Taxpayers can seek to have an assessment reviewed by the Tribunal. However, there have been no reviews for some time due to the lack of a person for the Tribunal.

Royalty Withholding Tax for Landowners

Currently, royalties payable by resource projects to landowners are subject to withholding tax at the rate of five percent, unless the recipient landowners are duly registered for tax purposes. This low rate of withholding means the IRC has the burden of actively ensuring that the remaining tax that is likely to be payable on the payment is collected.

In order to facilitate the IRC's efforts to collect taxes from payments made to landowners, the withholding rate could be increased to the lowest positive personal income tax rate (currently 22 percent).

Question 10.1 – should the withholding rate on royalties paid by resource projects to landowners be increased to the prevailing lowest positive personal income tax rate?

Template Agreements

The ideas put forward in this issues paper would, if implemented, ensure that PNG's fiscal arrangements for mining and petroleum projects are transparent and provide a level playing field, with as little Government red tape affecting exploration and development as possible.

In order to proactively support these reforms, consideration could be given to developing and publishing template project agreements that form the basis of any new projects within the country. This will assist State agencies, including the State Solicitor General, to develop new project agreements in a timely manner.

Question 10.2 – should template project agreements that will form the basis of any new project agreements within the country be developed and published?

Fiscal Stability

Mining and petroleum companies are likely to seek some form of assurance of fiscal stability in case of changes in the law of critical fiscal terms. The case for giving such protection is that investors require certainty of critical fiscal terms in order to reduce the range of risks they face, and thus to increase the likelihood of a positive investment decision in the country.

This protection could be provided as a properly worded 'fiscal stability clause' in a petroleum agreement or mining contract if the law so authorises. It does not limit in any way the right of the country to change its law but only addresses what is the impact of a change in the law for the parties to an agreement/contract.

Most PNG agreements/contracts provide some fiscal stability, with some arguably being excessively generous, thereby unduly increasing the government's risk. These include 'most favoured taxpayer provisions' or 'indemnification/compensation provisions', which can constrain government decision making for other projects.

Fiscal stability clauses are not preferred. Such clauses limit the Government's ability to impose new laws on a project or renegotiate as circumstances change or more information becomes available. They can also be difficult for the tax authorities to administer - for example, due to uncertainties over what is covered by the stability clause.

A country such as PNG is more likely to be able to accept stability if certain minimum payments, such as royalties, are being made and the government can share in the upside of profitable outcomes (e.g. through the company income tax and rent targeting fiscal instruments). If the State gets an equitable share then it is less likely to seek alternative terms. If it is clear to the general public that the State is receiving a fair share political pressure for changes is less likely to arise. Correspondingly, if the investor's share of risks and benefits is in equilibrium, there is less likelihood of them seeking to minimise taxes.

If fiscal stability clauses are offered, then arguably protection should be restricted to the key rates of tax and duty, and to major deductions such as capital allowances explicitly listed in the clause, and should be symmetrical and time limited. The clause should apply to these listed key features applicable to the company on the date any agreement is signed. It should not extend to reasonable and non-discriminatory regulations or administrative rulings made for general improvement of the tax or duty systems.

The fiscal stability clause should also be symmetrical: the company will be exempted or indemnified from tax or duty increase but, by the same token, it should not benefit from decreases during the stability period. By making the clause symmetrical, certainty for the investor is not compromised while the risk to government revenues is reduced. The fiscal stability should also be time limited.

Clauses with 'most favoured taxpayer provisions' or 'indemnification/compensation provisions' should arguably be avoided. As discussed in Chapter 3, investors are globally mobile, and the relevant comparison is between fiscal regimes applicable across countries, not current and future fiscal regimes within a country.

PNG's practice of imposing a two (2) percent premium for a fiscal stability clause could be discontinued if the fiscal package is modified in line with other possible changes referred to in this paper to increase progressivity.

Question 10.3(a) provided a suitable rent tax is imposed on resource projects, should the *Resource Contracts Fiscal Stabilisation Act 2000* apply to new projects or not?

Question 10.3(b) otherwise, should fiscal stability obtained in exchange for a two percent tax rate premium be made symmetrical, time limited and limited to key rates of tax and duty and explicitly listed capital allowances?

Question 10.3(c) - what are stakeholders' views on offering 'most favoured taxpayer provisions' or 'indemnification/compensation provisions'?

Extractive Industries Transparency Initiative

In April 2013, the Government announced that it would implement the extractive industries transparency initiative to increase transparency and accountability of revenues generated from the mining, oil and gas sectors. The

Government said that it will work with industry and civil society organisations through the formation of a multi stakeholder group and development of a fully costed work plan for implementation. It is intended that, under this initiative, the Government will report production data, licensing information, and transfers made to local governments and state owned enterprise.

The Committee supports the Government's efforts in implementing this initiative.

Goods and Services Tax Deferral Scheme

The zero-rating of output from mining and petroleum companies is consistent with international practice, but the zero-rating of suppliers who supply goods and services to those companies should be reviewed. Most, if not all, of the output from the resources sector will be exported, and therefore zero-rated under the goods and services tax (GST) - that is, no GST is imposed on the supply of the goods or services and a credit is given for GST on inputs.

However, zero-rating supplies to the companies creates two main problems: (1) it opens up the GST system to revenue leakage through abuse; and (2) it significantly increases the workload of the IRC - rather than having to deal with a small number of mining and petroleum companies, it has to deal with, and often provide refunds to, a significantly larger number of suppliers. The IRC has to use a significant portion of its limited resources in dealing with this issue.

Removing the zero-rating for supplies to mining and petroleum companies will require prompt payment of refunds, and could be accompanied by the introduction of a GST deferred payment scheme. Export companies are often concerned that if they have to pay GST on inputs this can have cash flow consequences, especially if GST refunds are not paid promptly. Therefore, the IRC should ensure GST refunds to the mining and petroleum companies are paid promptly.

Another concern is the GST on import of large capital items. Rather than providing refunds, some countries offer a deferred payment scheme. Under a deferred payment scheme, the payment of GST on imports is delayed until filing the next GST return, at which time there will be a credit available to offset the potential GST on the imported equipment.

Question 10.4 – should a GST deferral scheme be introduced the payment of GST on imports is delayed until filing the next GST return. At which time there will be a credit available to offset the potential GST on the imported equipment?

Import Duties

Currently, there is an inconsistent approach to import duties for mining and petroleum projects. Some companies receive exemptions while others are only entitled to lower duty rates (e.g. some projects are entitled to duty rates based on a prescribed basket of goods).

Like the goods and services tax, the most significant impact for the sector is often duties on imported capital goods. Resource companies, which are seeking to make a substantial investment in a country, are likely to seek import duty exemptions or reductions for these capital goods. Such exemptions/reductions can also be sought as a way to minimise dealings with customs officials, where foreign companies with substantial import needs can be a target for corrupt behaviour.

The practice of some countries to deal with this issue is to exempt or offer lower duties on a 'positive list' of specialised equipment, such as for exploration and development, from import duties. If this is to apply, then the preferred approach is to limit the exemption/reduction to capital goods not available in the domestic market and further restricted by requiring the equipment be re-exported after its use (assuming the equipment has some remaining economic life). Project or time limitations could also apply.

While lower duty rates could continue to be provided for goods used in exploration and development, the rates should be applied consistently between projects. Items such as fuel, motor vehicles, and non-specialised consumables should not be exempt. This approach should reduce the opportunities for revenue leakage, while not inhibiting imports of specialised goods.

Question 10.5 – should import duty exemptions or lower rates be given to specifically listed specialised equipment not available in the market, but with the requirement that the equipment be re-exported after use if there is any remaining economic life?

ABBREVIATIONS

ACE:	Allowable Capital Expenditure
AEE:	Allowable Exploration Expenditure
APT:	Additional Profits Tax
BBL:	Barrels of oil
DMPGM:	Department of Minerals Policy and Geohazard Management
DTA:	Double Taxation Agreement
DWT:	Dividend Withholding Tax
GST:	Goods and Services Tax
IRC:	Internal Revenue Commission
ITA:	Income Tax Act
MRA:	Mineral Resources Authority
OGA:	Oil and Gas Act
PDL:	Petroleum Development License
PPL:	Petroleum Prospecting License
PRL:	Petroleum Retention License
PNG:	Papua New Guinea
ROR:	Rate of Return
Tcf:	Trillion cubic feet (gas volume)