Gas Transfer Price Methodology

The Government, in consultation with industry, developed the gas transfer price methodology to alleviate uncertainty surrounding integrated gas to liquids projects that source their natural gas in Commonwealth waters. This uncertainty existed because the natural gas production phase of the project is subject to Petroleum Resource Rent Tax (PRRT), *(Petroleum Resource Rent Tax – Overview)* while the conversion of the natural gas to other products, such as liquefied natural gas (LNG) or methanol, is not. When projects producing these products have an integrated ownership, an "arms length" price may not be negotiated when the gas is moved from the PRRT ringfence (as provided in the *Petroleum Resource Rent Tax Assessment Act 1987*) *(Resources Taxation Legislation)* to the downstream processing phase, resulting in uncertainty regarding how to equitably apportion rents.

Principles

A set of principles were developed by industry and government to provide a framework for establishing the gas transfer price. These principles were:

- only upstream activities are liable for PRRT;
- outcomes should be assessed against economic efficiency criteria;
- GTP methodology to apply to all integrated gas to liquids projects;
- project risks equitably reflected on all cost centres;
- the transfer price references the first commercial third party price for derivative products; and
- the transfer price is transparent, equitable, auditable and simple to administer.

The Commonwealth announced in December 1998 that it would use the "residual price methodology" (RPM) to determine the gas transfer price. This price would be used to determine the project's PRRT liability. A gas transfer price would only apply when no comparable commercially negotiated arms length price is available.

Calculation

Reflecting these principles, the RPM is structured to allow investors to forecast the tax liability for their project. Two widely accepted formulae, utilising the netback and the cost plus approaches, are used to determine notional gas prices for the upstream and downstream components.

The netback method identifies all the relevant costs incurred in the downstream operation, and then subtracts those costs, including an allowance for capital expenditure, from the total revenues realised from selling the liquefied product. This provides a notional maximum "arms length" price a downstream producer (liquefier) can pay for the natural gas feedstock in order to earn the minimum return necessary to continue production.

The cost plus price does not reference the final market LNG price, rather it is based on the total costs in the natural gas production process, including an allowance for capital expenditure. This provides the notional minimum price the upstream producer requires to continue supplying natural gas to the LNG plant.

NETBACK AND COST PLUS PRICE FORMULAE

$$\text{Netback Price} = \frac{\text{GTL Revenues - GTL Costs}}{\text{Natural Gas Volumes}}$$

$$\text{Cost Plus Price} = \frac{\text{Gas Extraction Costs}}{\text{Natural Gas Volume}}$$

In theory, a fully competitive market should produce conditions where the project's netback and cost plus prices are equal. In practice, rigidity in the supply of inputs and other demand-related factors result in a divergence of the two prices. Normally, this provides an outcome where the netback price is greater than the cost plus price. The difference represents the economic rents associated with the project, and is also known as residual profit (refer Figure below).