SUPREME COURT OF QUEENSLAND

CITATION:	*Australia Pacific LNG Pty Limited & Ors v The Treasurer, Minister for Aboriginal and Torres Strait Islander Partnerships and Minister for Sport* [2020] QCA 15
PARTIES:	**AUSTRALIA PACIFIC LNG PTY LIMITED** ACN 001 646 331 (first appellant) **AUSTRALIAN PACIFIC LNG (CSG) PTY LIMITED** ACN 099 577 769 (second appellant) **AUSTRALIAN PACIFIC LNG CSG MARKETING PTY LIMITED** ACN 008 750 945 (third appellant) **AUSTRALIA PACIFIC LNG (MOURA) PTY LIMITED** ACN 064 989 813 (fourth appellant) **v** **THE TREASURER, MINISTER FOR ABORIGINAL AND TORRES STRAIT ISLANDER PARTNERSHIPS AND MINISTER FOR SPORT** (respondent)
FILE NO/S:	Appeal No 6507 of 2019 SC No 1027 of 2016
DIVISION:	Court of Appeal
PROCEEDING:	General Civil Appeal
ORIGINATING COURT:	Supreme Court at Brisbane – [2019] QSC 124 (Bond J)
DELIVERED ON:	7 February 2020
DELIVERED AT:	Brisbane
HEARING DATE:	26 November 2019
JUDGES:	Morrison and Philippides JJA and Mullins AJA
ORDERS:	**1. Appeal dismissed.** **2. The appellants pay the respondent's costs of and incidental to the appeal.**
CATCHWORDS:	ADMINISTRATIVE LAW – JUDICIAL REVIEW – REVIEWABLE DECISIONS AND CONDUCT – GENERALLY – APPEAL OF DECISION TO DISMISS APPLICATION – where the appellants are a producer of liquefied natural gas and were liable to pay royalties – where the *Petroleum and Gas (Production and Safety) Regulation* 2004 (Qld) holds that a producer can apply to the Minister for

a decision about how one or more of the components of the wellhead value of petroleum disposed by the producer must be worked out for a particular period – where the appellants applied to the Minister for a decision – where the Minister's decision was challenged in the matter below – where the challenge was successful and the decision was set aside – where the learned trial judge dismissed an application by the appellants for a declaration that the Minister had adopted a method which was not capable of determining what the *Regulation* requires, namely "the amount that the petroleum could reasonably be expected to realise if it was sold on a commercial basis" – where the appellants appeal against the dismissal of the application – whether the learned trial judge should have allowed the application

APPEAL AND NEW TRIAL – APPEAL - GENERAL PRINCIPLES – INTERFERENCE WITH DISCRETION OF COURT BELOW – IN GENERAL – OTHER MATTERS – where it is contended that the Minister exceeded jurisdiction by adopting a formula that did not comply with s 148 of the *Regulation* – where it was contended that the adopted formula wrongly assumed that the sold petroleum was LNG and not feedstock gas – where it was submitted that the formula "involves a legal error because it has the effect of assuming the full potential of feedstock petroleum at the first point of disposal as actually having been realised as LNG, when that potential is not realised at that point, and it thereby values the wrong petroleum" – whether the Minister exceeded jurisdiction with the formula adopted – whether the formula that the Minister adopted wrongly assumed the type of petroleum – whether the adopted formula involves a legal error

Petroleum and Gas (Production and Safety) Act 2004 (Qld) (superseded), s 590
Petroleum and Gas (Production and Safety) Regulation 2004 (Qld) (superseded), s 148, s 148E, 148F, s 148G

Spencer v The Commonwealth (1907) 5 CLR 418; [1907] HCA 82, mentioned
Turner v Minister of Public Instruction (1956) 95 CLR 245; [1956] HCA 7, cited

COUNSEL: L F Kelly QC, with M F Johnston, for the appellants
P A Looney QC, with A D Scott, for the respondent

SOLICITORS: Clayton Utz for the appellants
Crown Law for the respondent

[1] **MORRISON JA:** Australia Pacific LNG Pty Ltd[1] is part of a group of companies which are involved in a project converting coal seam gas into liquefied natural gas, then selling it to overseas buyers.

[2] At one end of the project supply chain is the producer, which extracts coal seam gas from wells. That raw coal seam gas is transported by pipeline to the next stage, the processing plant, where it is treated, converting it into what is called "feedstock gas". It is then transported by pipeline to the next stage, the liquefaction facility, where it is converted into liquefied natural gas (LNG).

[3] As a producer of liquefied natural gas APLNG was liable to pay a royalty under the *Petroleum and Gas (Royalty) Regulation* 2004 (Qld). That royalty is assessed at the "first point of disposal", which is when the feedstock gas leaves the processing plant, and is transported to the liquefaction plant. Pursuant to s 147C of the *Regulation* that was to be "at the rate of 10% of the wellhead value of the petroleum disposed of … during a royalty return period".

[4] Under the *Regulation* a producer could apply to the Minister for Aboriginal and Torres Strait Islander Partnership for a petroleum royalty decision about "how 1 or more of the components of the wellhead value of petroleum disposed of … by the petroleum producer must be worked out for a … particular period".

[5] APLNG applied to the Minister for a decision as to one component of the wellhead value of petroleum to be calculated, namely the component under s 148(1)(a) of the *Regulation*: "the amount that the petroleum could reasonably be expected to realise if it were sold on a commercial basis".

[6] The Minister delivered the decision on 16 December 2015. For the purpose of making that decision the Minister was permitted to state a method or formula. The decision adopted a method, called the "Netback Method", proposed by Lonergan Edwards & Associates (**Lonergan**), one of the experts retained to make submissions to the Minister as to the appropriate method of calculation.

[7] The Minister's decision was challenged on an application for statutory order of review under the *Judicial Review Act* 1991 (Qld). That challenge was successful. The decision was declared invalid and set aside.[2] However, the learned primary judge dismissed an application by APLNG for a declaration that the Minister had adopted a method which was not capable of determining what the *Regulation* requires, namely "the amount that the petroleum could reasonably be expected to realise if it was sold on a commercial basis".

[8] APLNG appeals against the dismissal of that application.

The regulatory framework

[9] Petroleum producers must pay a royalty under s 590 of the *Petroleum and Gas (Production and Safety) Act* 2004 (Qld). It relevantly provides:

> "**590 Imposition of petroleum royalty on petroleum producers**

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1 To which I shall refer as APLNG.

2 *Australia Pacific LNG Pty Ltd & Ors v The Treasurer, Minister for Aboriginal and Torres Strait Islander Partnerships and Minister for Sport* [2019] QSC 124.

> (1) A petroleum producer must pay the State petroleum royalty for petroleum that the producer produces …
>
> (2) The petroleum royalty—
>
> (a) must be paid on or before the time prescribed under a regulation; and
>
> (b) is payable at the rate prescribed under a regulation on the value of the petroleum at the prescribed time.
>
> (3) The value of petroleum for the petroleum royalty is the value provided for under a regulation or worked out in the way prescribed under a regulation."

[10] The definition of "petroleum" includes coal seam gas and LNG: s 10 of the *Act*.

[11] A petroleum royalty is payable for the royalty return period in which the petroleum is "disposed of": s 147(1)(a) of the *Regulation*. That section applies here. The "royalty return period" is the quarterly period for which a royalty return must be lodged: Schedule 2 of the *Act* and s 146A of the *Regulation*. A producer disposes of petroleum when it sells or otherwise transfers ownership of the petroleum to another person (or when it flares, vents or uses the petroleum): s 147(2) of the *Regulation*.

[12] Unless otherwise required by the Minister, the producer must, by the last business day of the month immediately following the royalty return period in which the petroleum was disposed of,[3] lodge a written return containing prescribed "royalty information": s 594 of the *Act*. Section 149 of the *Regulation* specifies what information is required:

(a) the wellhead value of the petroleum disposed of by the petroleum producer during the royalty return period;

(b) a breakdown of certain prescribed expenses and other deductions necessary to be made for working out the wellhead value; and

(c) for each relevant petroleum product disposed of by the producer during the royalty return period, the volume of the product disposed of and the amount of any revenue earned by the producer in relation to the product.

[13] Unless the Minister has allowed the producer to pay the royalty on the same day as the return is lodged,[4] the royalty is payable in three instalments, the last of which falls on the day the royalty return must be lodged: s 147(3) of the *Regulation*. Provision is made for how much the instalments are (s 147A(2) and s 147A(3) of the *Regulation*), and also that the producer can elect to pay on a monthly basis: s 147A and s 147B of the *Regulation*.

[14] The producer must also lodge an annual royalty return for each annual return period, for so long as the petroleum producer owns petroleum for which a royalty is, or could be payable, the annual return must state the royalty information for that period: s 599 of the *Act*.

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3 Referred to as the "ordinary due date".

4 Which the Minister may do under s 147(5) of the *Regulation*.

[15] The Minister must make an assessment of the amount of petroleum royalty for each royalty return and annual royalty return: s 599B(1) and s 599D of the *Act*. If the producer has not lodged a return as required the Minister may make a default assessment if satisfied that an amount is payable: s 599B(2) and s 599D of the *Act*. Provision is made for reassessment in appropriate circumstances: s 599C of the *Act*.

[16] Once an assessment or reassessment has been made the Minister must give the producer an assessment notice: s 599E of the *Ac*t. The notice must identify various matters, including whether further monies are payable consequent upon the assessment or reassessment, and, if so, the amount, the due date, and the amount of penalty which might be payable: s 599E and s 601 of the *Act*. Provision is made as to the amount of the penalties: s 601(2) of the *Act*.

[17] Provision is also made for the Minister to require a petroleum producer to provide a royalty estimate for the petroleum producer for a stated future period: s 599A of the *Act* and s 149B of the *Regulation*. And provision is also made for the Minister to estimate the royalty return where the petroleum producer has not lodged a royalty return for the previous royalty return period: s 147A(5) and s 147B(2) of the *Regulation*. Where estimates are used the petroleum royalty payable for the first and second instalments is the estimated amount: s 147A(5)(b) of the *Regulation*.

[18] Unpaid royalties are recoverable as a debt: s 603 of the *Act*.

[19] Therefore the liability to pay a royalty only accrues once a petroleum producer is in a position to dispose of petroleum during a royalty return period. Once that occurs the *Act* and *Regulation* provide a comprehensive regulatory structure which requires regular and accurate calculation of the amounts payable, and payment on or before set dates. Failure to do so exposes the producer to the imposition of default interest and significant penalties.

Calculation of the royalty

[20] Section 147C of the *Regulation* identifies the rate, the value and the prescribed time. As it then was, it relevantly provided:[5]

> "Petroleum royalty payable by a petroleum producer is payable at the rate of 10% of the wellhead value of the petroleum disposed of … by the petroleum producer during a royalty return period."

[21] As mentioned above, petroleum is "disposed of" if the producer "sells or otherwise transfers ownership of the petroleum to another person (or when it flares, vents or uses the petroleum)".

[22] The calculation of the wellhead value of petroleum is dealt with in s 148 of the *Regulation*. It relevantly provides:

> "**148 Working out wellhead value of petroleum**
>
> (1) The wellhead value of petroleum disposed of … by a petroleum producer in a royalty return period is—
>
> (a) the amount that the petroleum could reasonably be expected to realise if it were sold on a commercial basis; less

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5 The rate increased to 12.5 per cent in 2019.

(b) the sum of the following—

(i) the expenses for the royalty return period mentioned in subsection (2);

(ii) any negative wellhead value deducted under subsection (4).

(2) For subsection (1)(b)(i), the expenses are each of the following—

(a) a pipeline tariff or other charge paid or payable by the petroleum producer to a third party for transporting the petroleum through a pipeline to the point of its disposal, if the Minister reasonably believes the amount of the tariff is reasonable on a commercial basis;

(b) a processing plant toll or other charge paid or payable by the petroleum producer to a third party for processing the petroleum before it is disposed of, if the toll is calculated—

(i) on a commercial basis; or

(ii) if the Minister reasonably believes that use of the plant by other petroleum producers or for other purposes makes another basis for charging the most practicable basis—on the other basis;

(c) depreciation of capital expenditure by the petroleum producer on a petroleum facility or pipeline used for processing the petroleum or transporting it from the wellhead of the well in which it was produced to the point of its disposal, allocated over—

(i) 10 years; or

(ii) a shorter period decided by the Minister, if the Minister reasonably believes the shorter period is reasonable having regard to the expected potential for production of the natural underground reservoir from which the petroleum is produced;

(d) an operating cost incurred, or to be incurred, by the petroleum producer that directly relates to—

(i) treating, processing or refining the petroleum before it is disposed of; or

(ii) transporting the petroleum to the point of its disposal;

(e) another expense incurred, or to be incurred, by the petroleum producer in relation to the operation of the site at which the petroleum was produced that is approved by the Minister for the purpose of this subsection."

[23] As was pointed out by the learned primary judge, the evident goal of the calculation under s 148 of the *Regulation* is to establish a value for the petroleum disposed of,

by sale or other ownership transfer during a particular period, for the purpose of the royalty calculation. However, the revenue figure from which the expenses are deducted is not an actual revenue figure but rather a hypothetical figure, namely "the amount that the petroleum could reasonably be expected to realise if it were sold on a commercial basis". Identifying that figure requires some form of valuation process.

[24] Pursuant to s 148B(1)(b) of the *Regulation* a petroleum producer may apply to the Minister:

> " … for a decision (a ***petroleum royalty decision***) about how 1 or more of the components of the wellhead value of petroleum disposed of or produced by the petroleum producer must be worked out for a particular transaction or particular period."

[25] The term "component" is defined in s 148A of the *Regulation*, relevantly as follows:

> "***component***, of the wellhead value of petroleum disposed of or produced by a petroleum producer in a royalty return period, means—
>
> (a) an element used to work out the amount under section 148(1)(a) that the petroleum could reasonably be expected to realise; …"

[26] Section 148D provides when an application for a petroleum royalty decision must be made, and s 148E specifies the requirements for making the application. They include:

> "(c) state why the petroleum producer is seeking the petroleum royalty decision; and
>
> (d) include a statement about how the petroleum producer proposes a component of the wellhead value of the petroleum should be worked out for a particular transaction or particular period; and
>
> *Examples—*
>
> - a fixed value with adjustments in particular circumstances
> - a formula for deciding the market value. …"

[27] Section 148F(2) of the *Regulation* relevantly provides that the petroleum royalty decision may state:

> "(a) a method or formula—
>
> (i) for deciding the market value of the petroleum; or
>
> (ii) for working out particular tolls or tariffs paid or payable by the petroleum producer; or
>
> (iii) for adjusting the market value of the petroleum or the tolls or tariffs in particular circumstances; or

(iv) to be used for working out any other component of the wellhead value of the petroleum; and

(b) the period for which the petroleum royalty decision applies; and

(c) when the petroleum royalty decision is to be reviewed."

[28] The Minister is given a broad discretion as to the factors to take into account when considering the making of a petroleum royalty decision. Section 148G of the *Regulation* provides for the following criteria:

> "(a) the amount for which petroleum has been sold in similar circumstances;
>
> (b) how the value of the petroleum can be adjusted to reflect changes to the market value of the petroleum;
>
> (c) the expenses likely to be incurred by the petroleum producer in arms-length transactions at market value;
>
> (d) the period for which the petroleum royalty decision, or aspects of the decision, will apply;
>
> (e) the need for any future adjustment of the petroleum royalty decision or aspects of the decision;
>
> (f) any submissions made to the Minister by the petroleum producer in relation to a component of the wellhead value of the petroleum;
>
> (g) any other relevant matter."

The application for a petroleum royalty decision

[29] APLNG applied for a petroleum royalty decision under s 148D of the *Regulation*. The nature of the application was accurately summarised by the learned primary judge:[6]

> "It advised the Minister that the integrated nature of the APLNG Project, with common ownership of the companies involved across the gas chain, meant that there would not be an arm's-length value of gas negotiated in respect of the feedstock petroleum. Accordingly, it sought a petroleum royalty decision in respect of how it should go about the calculation for the purposes of s 148(1)(a) of the Regulation of the amount that the feedstock petroleum could reasonably be expected to realise if it were sold on a commercial basis."

[30] The application explained the way the project was structured, the difference between operations upstream and downstream from the point of first disposal, and how the LNG would be sold. It also presented submissions as to what it contended was the appropriate methodology for calculating the amount that the feedstock petroleum could reasonably be expected to realise if it were sold on a commercial basis.

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6 Reasons below at [40].

[31] One annexure was a report from Ernst & Young, which identified various competing methodologies. I need only refer to two of those methodologies, one called the Comparable Uncontrolled Price Method, and the other, the Netback Method.

[32] They were described, at a conceptual level, by the learned primary judge:[7]

> "(b) The "Netback Method", in which the question of market value of the feedstock petroleum at the first point of disposal would be approached from the downstream side of the disposal. The method would identify the ascertainable market price of the LNG when sold externally and would deduct from that price an appropriate gross margin to reflect the amount which the seller would seek (1) to cover its selling and other operating expenses and (2) to make an appropriate return on its capital, taking into account the capital expenditure it had incurred and the risks it had assumed. The theory would be that such a calculation would derive the maximum price that the seller would be prepared to pay the upstream producer for the feedstock gas which it had sold externally.
>
> …
>
> (d) The "Residual Price Method" … in which market value of the feedstock petroleum would be ascertained … by –
>
> (i) making a cost plus calculation to determine the price for which a seller of feedstock gas at the first point of disposal would sell its gas for in order to cover its upstream costs;
>
> (ii) making a netback calculation to determine the maximum price that would be paid for the feedstock gas by the buyer at that point to allow the buyer to cover its downstream costs taking into account the price which would be obtained for the sale of LNG; and
>
> (iii) then assuming that the market value of the feedstock gas at the first point of disposal would be the point half way between those two figures, on the basis that profit would be allocated equally between the upstream and downstream points and the market value would be treated as the price so identified."

[33] Ernst & Young's report identified the nature of the judgment involved in selecting the appropriate methodology, and the approach required:[8]

> "The choice of adopting an appropriate arm's length transfer pricing methodology and the way that methodology is able to be applied to demonstrate the arm's length nature of transfer prices will depend on the circumstances of each transaction. However, in accordance with the OECD and ATO guidelines the choice of the most appropriate

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7 Reasons below at [38].

8 Ernst & Young Report, June 2011.

methodology is to be based on a practical weighting of the evidence having regard to:

- the nature of the activities being examined;
- the availability, coverage and reliability of the data;
- the degree of comparability that exists between the controlled and uncontrolled dealings or between enterprises undertaking the dealings, including all the circumstances in which the dealings took place; and
- the nature and extent of any assumptions.

Further, in assessing the degree of comparability that exists between the controlled and uncontrolled dealings, the ATO and the OECD list the following five factors which need to be considered:

- characteristics of the property or services;
- functions performed, assets contributed and the risk assumed by each party;
- contractual terms, e.g. duration, rights, payments;
- business strategies, e.g. market positioning and strategic direction; and
- economic and market circumstances.

Whilst there is no formal hierarchy of transfer pricing methodologies, the OECD and the ATO will generally seek to use the transfer pricing method that is best suited or most appropriate to the circumstances of the particular case."

[34] In respect of that process Ernst & Young concluded with this remark:

> "Accordingly, whichever transfer pricing method is chosen as the most appropriate for determining the wellhead value of the CSG, it must have regard to the functions, assets and risks that are present across the upstream and downstream operations, including the valuable intangible assets present in the downstream operations. Should a particular transfer pricing method not have regard to this, that transfer pricing methodology would not be considered an appropriate transfer pricing methodology in accordance with the OECD and ATO guidelines."

[35] Ernst & Young concluded that the most appropriate was the Comparable Uncontrolled Price Method, however in the absence of data which permitted its use, the Residual Profit Split Method was appropriate, or the simplified version of that method, the Residual Price Method, as it specifically took into consideration and attributed value to the respective key functions performed, intangible assets utilised and risks borne by both the upstream and downstream operators.

[36] Ultimately APLNG's application conceded that there was no data to enable the Comparable Uncontrolled Price Method to be used, and proposed the Residual Price Method.

The Minister's decision

[37] The Minister was provided with competing expert advice about the most appropriate method to be adopted. For the producers, reports from Ernst & Young and a number of other experts were provided, proposing the adoption of the Residual Price Method. For the Office of State Revenue (OSR), three reports were provided from Lonergan, which proposed a variant of the Netback Method, the Adopted Netback Method, as the appropriate method to adopt. The process of competing reports and submissions continued for some time, and the OSR provided various briefing notes to the Minister.

[38] The decision attached a Schedule 2, which specified a formula for deciding the market value of the petroleum. It was common ground that the formula was the Netback Method.

[39] The principal formula was expressed as follows:

$$MV = \frac{{}^{V}{}_{LNG} \times {}^{P}{}_{LNG} - {}^{V}{}_{Port} \times {}^{Toll}{}_{Loading} - {}^{V}{}_{Plant} \times {}^{Toll}{}_{Processing} - {}^{V}{}_{Pipeline} \times {}^{Toll}{}_{Transport}}{{}^{V}{}_{Pipeline}}$$

[40] The table beneath the formula in Annexure A defines the variables used in it:

(a) MV = Market Value gigajoule (GJ) of Petroleum disposed of by a Producer for the Relevant Period.

(b) VLNG = Volume of LNG in GJ exported by APLNG Processing for the Relevant Period.

(c) PLNG = Volume-weighted average price per GJ calculated based on the total proceeds from the sales of LNG and the total volume of LNG sold during the Relevant Period. The proceeds from the sales of LNG during the Relevant Period include the proceeds from the sales of LNG at FOB, and if not FOB the netted back FOB contract prices, of LNG exported by APLNG Processing for the Relevant Period plus any additional payments made or due to any APLNG project entitles or related parties in relation to the LNG sales under the SPAs.

(d) ${}^{V}{}_{Port}$ = The volume of LNG in GJ entering the storage and port loading facilities for the Relevant Period.

(e) ${}^{Toll}{}_{Loading}$ = Notional loading toll per GJ of LNG entering the storage and port loading facilities (in A$) for the Relevant Period, calculated in accordance with the following formula and relevant inputs.

(f) ${}^{V}{}_{Plant}$ = Volume of gas in GJ entering the APLNG liquefaction plant in relation Train 1 or Train 2 for the Relevant Period.

(g) ${}^{Toll}{}_{Processing}$ = Notional processing toll per GJ of gas entering the APLNG liquefaction plant (in A$) for the Relevant Period, calculated in accordance with the following formula and relevant inputs.

(h) ${}^{Toll}{}_{Transport}$ = Notional transport toll per GJ of gas entering the transmission pipeline (in A$) for the Relevant Period, calculated in accordance with the following formula and relevant inputs.

(i) $^{V}{}_{Pipeline}$ = Volume of gas in GJ entering the transmission pipeline for the Relevant Period.

[41] Expressed more simply the formula determined market value by starting with the price achieved for all sales of LNG exported ($^{V}{}_{LNG} \times {}^{P}{}_{LNG}$). From that is deducted the costs incurred in transporting the LNG through the pipeline from the wellhead to the export facility, and the charges levied into the liquefaction plant and the storage and port loading facility.

[42] The costs of piping the LNG from the wellhead to the export facility is expressed as a toll ($^{V}{}_{Pipeline} \times {}^{Toll}{}_{Transport}$). The costs or charges of piping the LNG into the liquefaction plant is also expressed as a toll ($^{V}{}_{Plant} \times {}^{Toll}{}_{Processing}$), as is the cost or charges of piping the LNG into the storage and port loading facility from where the LNG would be exported ($^{V}{}_{Port} \times {}^{Toll}{}_{Loading}$).

[43] The Minister adopted the analysis of Lonergan. That expert's opinion was that the appropriate basis upon which to calculate the formula to establish market value should be one where the upstream assets and the downstream assets are notionally or actually to be developed by separate, arms-length, knowledgeable parties, who enter into commercial negotiations to determine a method or formula by which the price for the feedstock gas at the first point of disposal is to be derived, that agreement being made prior to committing to the joint development.

Grounds 1 & 2 – formula non-compliant with s 148 of the *Regulation*

[44] These grounds attacked the Minister's decision on the basis that the Minister exceeded jurisdiction by adopting a formula that did not comply with s 148 of the *Regulation*.

[45] Mr Kelly QC, appearing for APLNG, contended in a variety of ways that the formula adopted by the Minister "determines an amount for tolls or access charges for the hypothetical upstream operator to use downstream infrastructure of hypothetical owners of the infrastructure, as opposed to determining the amount that the relevant petroleum … could reasonably be expected to realise if it were sold on a commercial basis". The contentions were summarised:[9]

> "(a) first, the Formula determines an amount for *tolls or access charges* for the hypothetical upstream operator to use downstream infrastructure of hypothetical owners of the infrastructure, as opposed to determining the amount that the relevant petroleum (known as *"feedstock petroleum"*) could reasonably be expected to realise if it *were sold* on a commercial basis (the **Access Charges Point);**
>
> (b) secondly, the Formula has the effect of erroneously treating the hypothetical downstream operator as a mere *provider of infrastructure* in return for an access charge or toll in the same way as an infrastructure provider of rail or port facilities, as opposed to treating the hypothetical downstream operator as a *purchaser* of the feedstock petroleum, taking ownership of the feedstock petroleum and then converting it to something

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9 Appellants' Amended Outline, para 4.

> else (namely, LNG) for subsequent sale to overseas entities (the **Infrastructure Provider Point)**."

[46] That submission was developed further, by reference to s 148(1)(a) of the *Regulation*, to contend that the Lonergan approach was akin to the owner of the feedstock petroleum retaining ownership and simply being charged tolls for use of infrastructure by three separate downstream owners:[10]

> "This exposes the legal error the subject of the Access Charges Point. That is because the relevant and only transaction on the proper construction of s148(1)(a) of the Regulation is a *sale on a commercial basis* of the feedstock petroleum, and not a commercial transaction for *providing the upstream operator with use and access to the downstream infrastructure in return for a toll*. The owner of the feedstock petroleum (the upstream operator) is meant to be *selling* the feedstock petroleum, and not retaining ownership of that petroleum and seeking access to downstream infrastructure and paying an access toll. The transactions – a toll for access versus sale of a commodity on a commercial basis – are necessarily different.
>
> …
>
> It is also relevant to note that the Formula replicates four notional parties to various transactions to access downstream infrastructure – namely, the upstream owner of the feedstock petroleum, and *three separate notional owners* of the downstream infrastructure. The *"sale"* of feedstock petroleum between *a seller* and *a buyer* is necessarily different to multipartite commercial transactions between an owner of feedstock petroleum and three separate owners of downstream infrastructure concerning the feedstock owner's access to that downstream infrastructure."

[47] The submission continued that the Minister had exceeded jurisdiction when making the decision. This submission was expressed thus:[11]

> "The Minister's jurisdiction and statutory task was *limited to* making a petroleum royalty decision about how that component of the wellhead value outlined in s148(1)(a) of the Regulation - *"the amount that the petroleum could reasonably be expected to realise if it were sold on a commercial basis"* – must be worked out for a particular transaction or period. The important point is that the Minister had no power, authority or jurisdiction (and it would be an error of law) to make a decision about how to work out matters with respect to any type of commercial transaction *other than* the amount the feedstock petroleum could reasonably be expected to realise if it were sold on a commercial basis."

Discussion

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10 Appellants' Amended Outline, paras 25 and 28; internal citation omitted.

11 Appellants' Amended Outline, para 12.

[48] It was common ground that the whole gas production, processing, transport, storage and sale process was reflected in a document entitled APLNG Value Chain.[12]

[49] The basic stages in the process are shown as a sequence commencing at the wells: (i) wells; (ii) processing plants; (iii) "first point of disposal", at the outlet valve of the processing plants; (iv) lateral pipelines and transmission pipeline; (v) liquefaction plant; (vi) storage; and (vii) shipping.

[50] The difficulty confronting the selection of a method or formula to calculate market value was that the APLNG Value Chain reveals that all companies in the process are part of the APLNG Group so that all parties, whether they be drillers or producers, processors, liquefaction facility owners, marketers or port storage facility owners, were inter-related. Some companies in the group had roles to play at various stages in the process. Thus, APLNG itself was a tenure holder, petroleum producer and a processor. And Australia Pacific LNG CSG Marketing Pty Ltd was a marketer operating at the point of production as well as a domestic marketer at the point where the gas is converted to LNG.

[51] The entire project can be viewed as a stream starting at the wellhead and ending at the port storage facility where the gas was shipped overseas. The market value was to be established at the "first point of disposal", that is, immediately after the feedstock gas had been processed into coal seam gas, and before it is piped to the liquefaction plant. Assets upstream of the first point of disposal are the wells and the processing plants. Assets downstream are the pipelines, liquefaction plant, storage and loading, and the port facility.

[52] It was common ground that the consequence of the inter-related structure of the project was that there were no arm's length transactions at any point of the process. That also meant that there were no arm's length sales of feedstock gas at the first point of disposal.

[53] Lonergan identified the task at the outset of the 2014 Report: addressing certain questions "with the ultimate goal of determining a method or formula to assess the market value of the LNG feedstock gas at the first point of disposal".[13] Then in the Executive Summary noted that "The focus of our assessment is to derive a method / formula to establish the market value of the feedstock gas at the first point of disposal for a given royalty period".[14]

[54] Lonergan's opinion was that the appropriate basis upon which to calculate the formula to establish market value should be one where the upstream assets and the downstream assets are notionally or actually to be developed by separate, arms-length, knowledgeable parties, who enter into commercial negotiations to determine a method or formula by which the price for the feedstock gas at the first point of disposal is to be derived prior to committing to the joint development.

[55] For that calculation, it was necessary to identify/analyse the rational mental/thought process adopted by a hypothetical arms-length developer of the upstream assets and a hypothetical arms-length developer of the downstream assets in the (hypothetical) commercial negotiations at the time the joint development decision is to be made.

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12 Exhibit 9; AB 1217.
13 Lonergan Report 23 September 2014, para 1(a), AB 533.
14 Lonergan Report para 6, AB 536.

[56] Lonergan's analysis was that in the hypothetical transaction the two parties would simultaneously enter into long term gas supply agreements, as a result of which risk would be passed upstream to the owner of the upstream assets. Such risk sharing arrangements were: "… consistent with the risk sharing arrangement between the arms-length owners of downstream infrastructure (rail and port) for bulk commodity exports such as coal and iron ore and the arms-length upstream commodity producers whereby commodity price risk and FX risk and other risk are passed upstream due to the presence [of the assumed risk sharing arrangements]."

[57] Lonergan thereby reasoned that the method or formula which would be agreed by the two hypothetical parties to the transaction would be based upon a "building block approach", which is "widely used by regulators to determine the appropriate annual revenue requirement for regulated infrastructure providers". Under this approach, a component of the method or formula that would be agreed by the parties to the hypothetical transaction for working out the value of the petroleum would be, in effect, tolls charged for the use of the downstream operator's assets, calculated to provide a return on capital, return of capital, operating costs and the costs of tax.

[58] In accordance with this approach Lonergan said that the parties would agree to a formula for calculating the price of the petroleum using a "Netback Method". Under this method:

(a) the LNG price is identified and from that is deducted an appropriate gross margin to reflect the amount which the seller would seek: (i) to cover its selling and other operating expenses; and (ii) to make an appropriate return;

(b) the "appropriate return" to the seller is calculated by use of the building block approach.

[59] The learned primary judge found that the Netback Method could be characterised as a method or formula for determining the market value. His Honour expressed his conclusions thus:[15]

> "[129] …the Adopted Netback Method assumes that the "sale" at the first point of disposal in the royalty period would take place pursuant to an arrangement struck at an antecedent arm's length negotiation between the putative seller and the putative buyer which dealt with the price which would be paid for the disposal of the feedstock gas in future relevant periods. Such an assumption can be regarded as seeking to identify the amount that the petroleum could reasonably be expected to realise "if it were sold on a commercial basis" at the first point of disposal. The alternative is to say that the Regulation required the method or formula stated by the Minister to model something which was incapable of existing. I think the meaning of "if it were sold on a commercial basis" is sufficiently flexible to encompass what has been assumed by the petroleum royalty decision.
>
> [130] With that as the base assumption, in theory a Netback Method could be characterised as an appropriate solution to the

15 Reasons below at [129]-[131].

problem of identifying the amount which feedstock gas would reasonably be expected to realise on such a sale. Its suitability in preference to other possible methodologies would depend upon the assessment of such considerations as those identified at [39] above, and whether the identification of the deductions from the market price occurred in such a way as would appropriately reflect the amount which downstream operator would seek in the hypothesised negotiation: (1) to cover its selling and other operating expenses, and (2) to make an appropriate return on its capital, taking into account the capital expenditure it had incurred and the risks it had assumed.

[131] It seems to me that the Adopted Netback Method must be properly characterised as a method or formula for deciding the amount that the petroleum could reasonably be expected to realise if it were sold on a commercial basis. The conceptual framework which underlines it cannot, as a matter of law, be demonstrated to give rise to a formula which is inapposite to the task for which it was stated."

[60] The royalty is payable on the wellhead value of the petroleum. Further, the royalty is assessed at the "first point of disposal" and is levied at the rate of 10 per cent of the wellhead value "of the petroleum disposed of". The petroleum "disposed of" is a reference to the "first point of disposal", and therefore the royalty is assessed on the petroleum disposed of at the first point of disposal.

[61] The wellhead value is "the amount that the petroleum could reasonably be expected to realise if it were sold on a commercial basis". It was that component upon which APLNG sought a Ministerial decision.

[62] Necessarily the market value depends upon hypothetical elements. The use of the phrases "could reasonably be expected to realise" and "if it were sold" make that plain. Thus the value is to be determined even though there may be no actual sale. That follows because petroleum can be "disposed of" without a sale or transfer of ownership, for example by use, flaring or venting. Thus, if petroleum is used, flared or vented by the producer, and there is no transfer of ownership at all, that petroleum is valued in the same way, ie to determine the amount that petroleum could reasonably be expected to realise if it were sold on a commercial basis.

[63] Equally, the market value is be determined in spite of an actual sale, for example if that sale is not at arm's length, or not "on a commercial basis".

[64] For those reasons it is wrong, in my view, to seek to define the hypothetical sale by looking to see if the arrangement has an actual passing of ownership. The assessment is to establish a value applicable at the first point of disposal, as if the petroleum was sold, not because it was.

[65] What the sections require is the notional "amount" that the petroleum might "realise". In my view, the realisable amount does not seek the notional sale price without offsetting costs. The assessment is directed at value, not sale price, and market value must factor in costs of holding or producing the asset that is being valued.

[66] The requirement that the hypothesised sale be on a "commercial basis" means, in my view, that the regulatory regime requires that the assessment of value be based on a net price notionally negotiated in an arm's length sale. So much is also evident from the terms of s 148(1) and s 148(2) of the *Regulation*, which deal with expenses to be deducted from the amount that the petroleum could reasonably be expected to realise in order to arrive at the wellhead value.

[67] Further, in my view, nothing in the relevant provisions calls for the notional sale to be between a vendor and purchaser who are the immediate parties either side of the first point of disposal. In other words, using the APLNG Value Chain, the market value does not necessarily require that the notional sale be between the processor who operates the processing plant at the first point of disposal, and the owner of the transmission pipeline or the operator of the liquefaction plant (the next downstream operators). All that is called for is an assessment based on a notional sale so that a value applicable at the first point of disposal is determined. Thus, that could be set on a notional sale between an overseas buyer and the processor, as long as it was on a commercial basis and reflected the amount that the petroleum could realise.

[68] Lonergan's explanation of the Netback Method was given in its 2014 report:[16]

> "7 The basis upon which the method / formula should be derived is one where **a hypothetical arm's length developer of the upstream assets and a hypothetical arm's length developer of the downstream assets enter into commercial negotiations on the joint development of the upstream segment and downstream segment of an integrated LNG project whose overall economic viability is underpinned by long-term LNG export agreements and expected substantial Asian demand for LNG**. In simple terms, the method / formula to establish the market value of gas should be derived in a context where the expected positive value created from the entire value chain needs to be hypothetically apportioned between the upstream segment and the downstream segment, given the relative risks involved and the alternative uses of the gas.
>
> 8 **The appropriate point in time at which a hypothetical arm's length developer of the upstream assets and a hypothetical arm's length developer of the downstream asset negotiate on the method / formula to finally establish the value of the feedstock gas should be at, or as at, the time just before the final joint development decision** because this is a relevant and important consideration for both parties before making their final decision on the joint development.
>
> 9 In this setting **the netback method under which the price of feedstock gas at the first point of disposal is set based on deducting the correctly calculated downstream costs from the ascertainable market value of LNG (e.g. on a free on board (FOB) basis)** is the method / formula acceptable to

[16] Lonergan Report 23, AB 533, at 536. Emphasis added.

both parties in the absence of material adverse circumstances (e.g. material adverse changes in LNG export prices and/or FX rates or material adverse changes in upstream gas reserves and resources with consequential adverse changes in the expected economic life of the upstream and downstream assets). The method / formula negotiated between these hypothetical rational parties at the time just before the final joint development decision should also allow for the fact that if and when the material adverse circumstances arise, both the netback method and the upstream cost plus method (reflecting the upstream costs of extracting and delivering the gas to the first point of disposal) should be considered, mirroring rational commercial negotiations between two arm's length knowledgeable parties, which endeavour to maintain a long-term symbiotic relationship."

[69] What is clear from that explanation is that the two parties under the Netback Method hypothetical sale are: (i) as vendor, the hypothetical arm's length developer of the upstream assets, and (ii) as purchaser, the hypothetical arm's length developer of the downstream assets. The downstream assets include the pipeline network, the liquefaction plant, and storage and port facility which is the point of overseas sale of the LNG.[17] The justification for that approach was also explained:[18]

"45 Central to the value allocation exercise is the need to establish the market value of a subject asset or a subject group of assets which is not readily observable, but belongs to a collection of assets whose total market value is readily observable or ascertainable.

46 Market value is generally defined in practice as the price that would be negotiated in an open and unrestricted market between a knowledgeable willing but not anxious buyer (WBNAB) and a knowledgeable willing but not anxious seller (WBNAS) acting at arm's length within a reasonable timeframe. This definition of market value is consistent with that set out in *Spencer v The Commonwealth* (1907) 5 CLR 418.

47 In the case of an integrated LNG project (or an integrated mining project in general), the value allocation exercise involves establishing the market value of gas (or a relevant mineral) at an intermediate point in the supply chain, given that the value of gas at the end product point of sale is readily ascertainable. The (intermediate) point at which market value is to be assessed is typically a point dividing, in some way, the supply chain between the upstream segment and the downstream segment.

48 As we understand it, what is required for royalty assessment purposes is the market value of the feedstock gas at the (notional) first point of disposal. Given the brand new long-

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[17] Lonergan report, para 49, AB 546.

[18] Lonergan report, paras 45- 48, AB 546; internal citation omitted.

term nature of the integrated LNG projects for which a PRD is or may be required, the appropriate basis upon which such method / formula is to be assessed should be one where the upstream assets and the downstream asset are notionally or actually to be developed by separate hypothetical arm's length knowledgeable parties who enter into commercial negotiations to determine a method / formula by which the price for the feedstock gas at the first point of disposal is to be derived prior to committing to the joint development (i.e. in an ex-ante sense, not ex-post sense)."

[70] That is why the hypothesised sale utilises the price of feedstock gas at the first point of disposal as set based on deducting the correctly calculated downstream costs from the ascertainable market value of LNG (e.g. on a free on board (FOB) basis). In other words, it uses the notional sale price obtainable for the ultimate sale of the LNG, and deducts the cost of getting the processed coal seam gas to that state (LNG, rather than coal seam gas), and that physical point (at the port and loaded on board for sale). Put differently, the formula assumes that the parties to the hypothetical arrangement have agreed to a sale of the feedstock gas, at the first point of disposal, for a price which would allow the hypothetical purchaser to recover its costs in transporting the feedstock gas, converting it to LNG for export, and storing and loading it, as well as a reasonable return on its investment.

[71] The method or formula proposed by Lonergan incorporated a calculation that gave a return on capital on downstream assets,[19] and the allocation of risk as between the two hypothetical negotiating parties was explained:[20]

"26 A key input to calculate a relevant notional toll is the required rate of return on the underlying downstream infrastructure asset. We have adopted a post-tax nominal WACC in our assessment of the required rate of return.

27 In assessing the required rate of return for each downstream infrastructure facility, we have recognised that:

(a) the change in risk profile from the pre-production period to the post-production period. The pre-production required rates of return are used to roll forward the pre-production capex to the date of production commencement to establish the asset base value of the relevant facility at that date

(b) the risk profile of the downstream infrastructure assets is significantly less than that of the upstream assets due to the passage of commodity price risk and FX risk upstream

(c) the upstream owner bears the volume risk if it transpires that there is less gas in the ground or available from third party upstream suppliers than has been contracted to the downstream operators

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19 Lonergan report, para 22, AB 539.

20 Lonergan report, paras 26-27, AB 541.

(d) the risk profile of the liquefaction plant is greater than the risk profile of the transmission pipeline and the wharf loading facility due to the complex operation, higher operating leverage, higher stranded asset risk and higher amount of capital at risk of the former."

[72] The commerciality of the hypothesized approach is underpinned by the assumption that the upstream operator has the knowledge and the capacity to convert the feedstock gas into LNG itself. That is, the Netback Method assumes that the downstream operator would have the expertise, experience, ability, financial capacity, market power and reputation to carry out the downstream activities. On that assumption the upstream operator would only be "willing" to sell the feedstock gas to the downstream operator for a price calculated in accordance with the Netback Method.[21]

[73] Further, adoption of that method also enables the hypothetical negotiating parties to factor in alterations to price and cost according to market fluctuations. Thus, as the passage above states, changes in LNG export prices or Foreign Exchange rates, or material adverse changes in upstream gas reserves and resources with consequential adverse changes in the expected economic life of the upstream and downstream assets, are encompassed within the negotiated basis of the realisable amount. Rational commercial parties would be assumed to take such a prudential approach in the hypothetical negotiations, given that the LNG project has a potentially long operating life well beyond the scope of short term economic cycles. As Lonergan went on to explain:[22]

"11 Unless they jeopardise the symbiotic relationship between the two parties, these ex-post differences (both favourable and unfavourable) are reflected through the choice of the inputs used to implement the netback method, rather than the variation of the method itself."

[74] Lonergan's approach, as explained in its 2014 report, assumed a transfer of the petroleum from the upstream operator to the downstream operator:[23]

"50 Given that a method / formula to establish the market value of the feedstock gas at the first point of disposal is agreed between a hypothetical arm's length developer of the upstream assets and a hypothetical arm's length developer of the downstream assets at the time the decision on the joint development is made, **there is an inherent linkage between the process agreed at the beginning of the integrated project (i.e. the method / formula) and the subsequent outcome (i.e. the calculated ongoing prices at which gas is transferred from the hypothetical arm's length developer / owner of the upstream assets to the hypothetical arm's length developer / owner of the downstream assets during the life of the integrated project).**

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21 Minister's decision, para 12a; AB 342-343; Lonergan 2015 Report, para 26(a)(i), AB 1097.
22 Lonergan Report, para 11, AB 537.
23 Lonergan Report, paras 50-51, AB 547; emphasis added.

> 51 This is because at any point during the life of the integrated project, the price at which the gas is bought / sold by the hypothetical arm's length developer / owner of the upstream assets and the hypothetical arm's length developer / owner of the downstream assets is determined according to the method / formula agreed between those parties at the beginning of the project."

[75] The Lonergan report also set out specific considerations in sections headed "The buyer's perspective" and "The seller's perspective",[24] and discussed the respective positions of the upstream operator (the seller) and the downstream operator (the buyer) in terms of what each would be expected to bargain in terms of price.[25]

[76] Later in the report Lonergan refers to the tolls, in paragraphs relied upon by Mr Kelly QC to contend that the method was not based on a sale but on charges for downstream operations. However, that discussion in the report was in the context of "Estimation issues" concerning the downstream costs. They did not alter the fundamental basis of the approach. The rationale for the incorporation of tolls in the method or formula was explained:[26]

> "112 In economic substance, the separate arm's length owner of the downstream infrastructure assets receive the relevant tolls (in A$) in return for the provision of downstream infrastructure services to the separate arm's length owner of the upstream assets.
>
> 113 We have assumed that, this is conceptually effected by back-to-back long-term gas supply agreements whereby:
>
> (a) the arm's length owner of the downstream infrastructure assets enter into a long-term (take or pay) gas supply agreement with the users of exported LNG under which LNG is supplied at US$ denominated JCC linked LNG export prices
>
> (b) **the arm's length owner of the downstream infrastructure assets simultaneously enter into a long-term gas supply agreement with the arm's length owner of the upstream assets under which feedstock gas is supplied at netback value denominated in A$ after deducting the A$ denominated toll from the A$ proceeds from the exports of LNG in US$**."

[77] In my view, that method does assess the value based on a net price notionally negotiated in an arm's length sale at the first point of disposal, on the basis that the purchaser is a party at the last point of the downstream assets, and the vendor is the upstream processor.[27] Though it may be overly simplistic, one way of

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24 AB 548-549.

25 Lonergan report, paras 66-67, AB 550.

26 Lonergan report, paras 112-113, AB 560-561; emphasis added.

27 I pause to note that the Netback Method proposed by Lonergan also comprehended sales of LNG into the domestic market, rather than overseas: Report para 92, AB 555.

characterising the notional transaction is that it is one where the exporter of LNG buys and takes delivery at the first point of disposal, and the price it is prepared to pay factors in the costs to it of getting the gas into liquefied form and loaded at the port. All the tolls applicable under the Netback Method reflect the costs of transporting the gas, liquefaction, storage and loading.

[78] For the reasons given above, APLNG's contentions must be rejected. The Netback Method provides a formula as to how value was to be determined between two hypothetical parties, one the vendor of the LNG, the other the purchaser. If the price is calculated correctly according to the agreed method / formula, it necessarily becomes the price agreed between the two arm's length commercial, knowledgeable parties to the transaction at a relevant point in time. That reflects the value applying the approach in *Spencer v The Commonwealth*.[28]

[79] It may also be noted that the criticism of the Lonergan approach that was advanced to the Minister did not advance the proposition that the Netback Method was simply the imposition of downstream tolls or access charges, and not a sale. Instead, the Lonergan approach was criticised for its assumptions and lack of credible assessment of project risks and rates of return, amongst other matters, whilst accepting that it attempted to analyse a hypothetical sale between two parties.[29]

[80] These grounds fail.

Ground 3 – wrong petroleum point

[81] This ground advanced the contention that the adopted formula wrongly assumed that the sold petroleum was LNG and not feedstock gas. Thus, it was said, the formula "involves a legal error because it has the effect of assuming the *full potential* of feedstock petroleum at the first point of disposal as actually having been *realised* as LNG, when that potential is not realised at that point, and it thereby values the wrong petroleum."[30] Relying upon *Turner v Minister of Public Instruction*[31] the alleged error was explained:

> "The legal error is explained by reference to an analogy with undeveloped land (akin to the feedstock petroleum) as against land which has been developed and had its full potential realised in sub-division (akin to the LNG ready for export at the port). In the case of hypothesising a sale of undeveloped land for valuation purposes, it would be an error of law to value the land as if its *potential* to be fully developed and subdivided had *already been realised* and existed at the date of the hypothetical sale transaction. This was the situation considered in *Turner v Minister of Public Instruction* (1956) 95 CLR 245 ***(Turner).***
>
> …
>
> The Formula (as shown by the multiplication in the numerator of *"VLNG x PLNG"*) takes the realisation of LNG as a *given*, as if the full potential of the feedstock petroleum had already been *realised* at the first point of disposal, and then the method merely seeks to

28 (1907) 5 CLR 418.

29 APLNG submission, paras 53-156, AB 635-664.

30 Appellants' Amended Outline, paras 32, 39; internal citation omitted.

31 (1956) 95 CLR 245, at 268-269, 291, 292.

> deduct tolls as the downstream costs for providing access to the downstream infrastructure. That is actually valuing the LNG as the *realised potential*, as a *given,* less tolls as downstream costs, and then seeking to make that the market value of the feedstock petroleum at the first point of disposal. The Minister has notionally brought what is only *potential* into *actual being* and valued the feedstock petroleum as if that potential has in fact been realised."

[82] These points were advanced before the learned primary judge, who rejected the applicability of *Turner*:[32]

> "[142] The problem with this contention is that it pays no regard to the conceptual framework which underlies the Adopted Netback Method. It pays no regard to the fact that the sale assumed was not a normal sale to a spot market for the sale of land, but a sale pursuant to an antecedent negotiation setting up a CSG to LNG development and allocating risk accordingly. *Turner* was irrelevant for assessing such a sale. The applicants' argument does not amount to a reason not to characterise the Adopted Netback Method as a method or formula for deciding the amount that the petroleum could reasonably be expected to realise if it were sold on a commercial basis. It is really yet another way of criticising as insufficient the ways in which the Adopted Netback Method formulated the deductions from the external market price sale. As I have said, if these were errors, they were which were within the Minister's jurisdiction to make. No error of law as alleged was made."

Discussion

[83] In my respectful view, reliance upon *Turner* is misplaced and the contentions should be rejected.

[84] First, *Turner* was a case of the valuation of a resumed parcel of unimproved land. The highest and best use of the land was if it was subdivided and those subdivided lots were then sold. At the date of valuation the subdivision had not occurred, and therefore the land's potential had not been realised. The trial judge adopted a hypothetical development approach to the valuation but allowed nothing for the risk of realisation nor the profit to be made on reselling the subdivided land. The questions which arose were whether deductions for the risk of realisation should be made, and also a further deduction for the profit a purchaser might make if the land was sold unimproved and then its subdivision potential was realised.

[85] The High Court held the deductions should be made as the potential for subdivision was not immediately realisable. Thus Dixon CJ cautioned against bringing "what is only potential into actual being and value it as if it existed", but that it was right to consider the "sale of the land as it was at the date of the resumption, that is un-subdivided, but having the clear potentiality that it was fit for subdivision".[33] Kitto J held that the risks had to be taken into account because "the land was simply

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32 Reasons below at [142].

33 *Turner* at 268-269.

incapable of immediate sale in subdivision, and it would necessarily remain incapable of sale in subdivision until time, trouble and expense had been laid out upon it".[34]

[86] The situation in *Turner* was completely different from that hypothesised by Lonergan. The Netback Method postulated a commercial agreement between the owner of the upstream assets and the owner of all the downstream assets. Thus, the purchaser was the entity that owned and operated the transmission pipelines, the liquefaction plant, and the storage and loading facilities at the port. On the hypothesis it had the present capacity to transport the coal seam gas and render it into LNG, and store, load and sell it. As the learned primary judge held, the sale assumed was not a normal sale to a spot market for the sale of land, but a sale pursuant to an antecedent negotiation setting up a CSG to LNG development and allocating risk accordingly.

[87] Secondly, the contentions again assume that the hypothetical sale which underpins the Netback Method was merely the retained ownership of the petroleum by the upstream owner, which had to pay a series of tolls. For the reasons given earlier, that approach mischaracterises the assumed sale. The hypothesis was that a commercial arrangement was made between the upstream owner as vendor, and the owner of all downstream assets, as purchaser. That necessarily proceeded on the basis that what was contemplated was completion of the gas to LNG project in all its phases, without the attendant uncertainty of the kind applicable to unrealised subdivisional potential in land.

[88] This ground fails.

Conclusion

[89] As the grounds of appeal have failed the appeal should be dismissed with costs.

[90] I propose the following orders:

1. Appeal dismissed.
2. The appellants pay the respondent's costs of and incidental to the appeal.

[91] **PHILIPPIDES JA:** I agree with the reasons of Morrison JA and the orders proposed by his Honour.

[92] **MULLINS AJA:** I agree with Morrison JA.

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34 *Turner* at 291-292, Fullagar J concurring.