1. Purpose

To provide an opportunity to comment on implementation of the volume model as the basis for imposing Queensland petroleum royalty.

2. Background

General

As part of the 2019-20 Queensland Budget, the Government announced a review of the design of Queensland’s petroleum royalty regime. The objectives of the petroleum royalty review (PRR) are to ensure greater certainty, equity and simplicity for all parties and identify opportunities to simplify the current regime, while providing an appropriate return to Queenslanders from their valuable non-renewable resources.

A working group independently chaired by The Honourable Jay Weatherill was formed to undertake the PRR. Mr Weatherill provided two reports to government, in December 2019 and February 2020. Following consideration of those reports, the Treasurer and Minister for Infrastructure and Planning announced a new petroleum royalty liability model on 8 June 2020.

Currently petroleum royalty is imposed at 12.5% of the wellhead value of petroleum disposed of during a return period. From 1 October 2020 petroleum royalty will instead be imposed by applying a prescribed royalty rate to the volume of petroleum produced during a return period. This is referred to as the volume model.

Consultation process

This consultation paper is the basis for seeking industry comments on implementation of the volume model. It sets out the basis for applying the volume model, including how the royalty rate will be determined for different types of petroleum, and the other changes that will support implementation of the new arrangements.

Written submissions are invited by Wednesday 24 June 2020 and should be made to Mr Daniel Fielding, Director Royalty at daniel.fielding@treasury.qld.gov.au.

Submissions are particularly sought on the specific questions noted in the consultation paper, but may address other issues considered relevant.

Given the government’s announcement of its decision to introduce the volume model for imposing petroleum royalty, the purpose of the consultation process is to ensure any administrative issues arising for its implementation are identified. The consultation process is limited accordingly. Given this objective, the consultation process does not include consideration of the petroleum royalty rates or benchmark prices.
3. Relationship between PRR and RAM Program

The PRR has been undertaken separately to the Office of State Revenue’s (OSR) Royalty Administration Modernisation (RAM) program. The RAM program focuses on royalty administration, with the objective being to apply the *Taxation Administration Act 2001* (TAA) to mineral and petroleum royalties by including the mineral and petroleum royalty legislation as revenue laws under the TAA. The royalty legislation, including the *Petroleum and Gas (Production and Safety) Act 2004* (Petroleum and Gas Act) and the *Petroleum and Gas (Royalty) Regulation 2004* (Petroleum and Gas Royalty Regulation), will continue to specify when and how royalty liability arises, including royalty rates, concessions and exemptions. This will include the basis for applying the volume model to determine petroleum royalty liability.

Public consultation on the RAM program has been finalised.

Given the relationship between the amendments required to the petroleum royalty legislation to implement the PRR and RAM programs, and the benefits RAM will deliver to mineral and petroleum royalty payers, both programs will be delivered together for commencement on 1 October 2020.

4. Volume model

Current basis for determining petroleum royalty liability – wellhead value

Petroleum royalty currently applies at the rate of 12.5% of the wellhead value of all petroleum disposed of by a petroleum producer during a period. For royalty purposes, petroleum includes oil, condensate, coal seam gas (CSG), natural gas and liquefied petroleum gas (LPG). Disposal includes sales to third parties and related entities, own-use, and flaring and venting.

*Wellhead value* is calculated by determining the amount the petroleum could reasonably be expected to realise if it were sold on a commercial basis, less specific statutory deductions for expenses incurred between the wellhead and disposal point, and less any negative wellhead value from a previous quarter within the same annual period.

Royalty is payable by the petroleum producer (the tenure holder) and liability arises at the first point of disposal, which is ordinarily post the wellhead. However, where arrangements exist within petroleum projects for non-tenure holders to commercialise petroleum produced by the project, disposal by the producer may be taken to occur at the wellhead immediately on production of the petroleum.

Volume model basis for determining petroleum royalty liability

From 1 October 2020, the basis on which petroleum royalty is imposed for all petroleum will change to the volume model. Under these arrangements, a petroleum royalty rate prescribed in the Petroleum and Gas Royalty Regulation will be applied to the volume of petroleum produced by a producer during a royalty return period. The basis for determining the applicable royalty rate is set out in *Determining petroleum royalty rate*. As noted in that section, there will be four liable classes of petroleum and separate rates will apply for each class.
Liability will arise when the petroleum is first produced, not at the time of disposal. For instance, if CSG is produced during March 2021 and is sold in April 2021, petroleum royalty will be payable for the CSG for the March 2021 quarter and all relevant details will need to be included in the March 2021 quarterly return. This can be contrasted to the current arrangements where petroleum royalty would be payable for the June 2021 quarter, being the period the petroleum is disposed of.

Although the Petroleum and Gas Act contemplates that petroleum produced and then stored in a natural underground reservoir before being recovered to ground level is again produced at the time of recovery, any potential for double liability will be addressed by making clear that royalty liability arises on first production and not on subsequent recovery.

**EXAMPLE 1**

Producer X produces 500,000 GJ of natural gas during the June 2021 quarter. 30,000 GJ is reinjected into a natural underground reservoir in June 2021 and is then recovered to ground level during the September 2021 quarter. A further 300,000 GJ of natural gas is produced during the September 2021 quarter.

Producer X will pay royalty on 500,000 GJ of gas for the June 2021 quarter i.e. the total volume produced during that quarter as it is all first produced then.

Producer X will pay royalty on 300,000 GJ of gas for the September 2021 quarter i.e. the total volume that is first produced during that quarter.

Where petroleum has been produced but not disposed of before 1 October 2020, transitional arrangements will require royalty for that petroleum to be paid for the return period ending 30 September 2020. This is discussed in more detail in *Lodgement of returns*.

**Measurement of petroleum produced**

Imposition of petroleum royalty using the volume model requires determination of the volume of petroleum produced. However, it is recognised there may be practical issues in measuring the volume of petroleum at the point of production, and that a reliable measurement may not be possible until the petroleum has undergone processing to remove impurities, such as water from CSG.

Accordingly, where the volume of liable petroleum is first accurately measurable at a point past the wellhead, it may be necessary to adjust the volume determined at that point to derive the volume produced. For instance, where the volume of CSG is measurable at the exit of the gas processing facility, that volume would need to be adjusted to add back any volume of CSG used by the producer, or flared or vented, between the wellhead and the measurement point.

OSR can currently decide a measurement of petroleum where no measurement has been made.1 This power will be extended to ensure OSR can also determine a measurement of petroleum where not satisfied with the measurement made by a producer.

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1 See s.592 Petroleum and Gas Act
A ruling setting out guidelines for measuring the volume of liable petroleum will be issued by OSR to assist producers.

Comment is sought regarding any particular issues that should be considered in:
(a) determining the volume of petroleum first produced during a period
(b) framing guidelines for measuring the volume of liable petroleum for each of the four classes of petroleum.

5. Liable classes of petroleum

General

From 1 October 2020 petroleum royalty will be payable at the prescribed rate on the volume of petroleum produced during a royalty return period, which will be either quarterly or annual (see Lodgement of returns). The applicable rate will depend on the petroleum type, with four classes of petroleum being established - three classes relating to petroleum in gas form and the other class relating to petroleum in liquid form.

Attachment 1 provides definitions for the key terms used in this paper.

Petroleum in gas form

For petroleum that is gas at standard temperature and pressure, the applicable royalty rate for a return period will depend on whether the gas is:

- produced by an LNG project and is not domestic gas (LNG project gas)
- supplied by a producer that is not a member of an LNG project to an LNG project (LNG supply gas) or
- domestic gas (as defined).

Different tiered royalty rates will apply to each class of gas, with the rate tiers for each class reflecting movements in the reference price for the gas (see Determining petroleum royalty rate).

Where there is an arm’s length sales price available for the gas sold during a return period, the intention is that this sales price will be the basis for determining the reference price for the producer, and the royalty rate will ordinarily be set by reference to that price. That is, the sales price for particular gas will determine the royalty rate tier applicable for the producer for the period, and that royalty rate will be applied to the volume of the gas produced in that period; in effect a personalised benchmark price.

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2 See s.11 Petroleum and Gas Act
3 This would include LPG.
A sales price will be regarded as arm’s length where the sale is to a person who is not a relevant entity for the producer or, if the producer sells to a relevant entity, there is ultimately a sale to a person who is not a relevant entity for either the producer or any person to whom the gas has been sold in a series of transactions (see definition of relevant entity at Attachment 1). That is, where the sale of gas by the liable producer is not taken to be arm’s length for this purpose, where possible there will be a tracing through any subsequent transaction or series of transactions after the producer’s sale to obtain an arm’s length sales price for the gas to determine the applicable royalty rate.

The basis for determining an arm’s length sales price is as follows.

- For LNG project gas - the per gigajoule (GJ) sale price of LNG under all ‘final’ LNG sales for the period. A ‘final’ LNG sale for a producer is the first LNG sale by the project that does not involve a member of the LNG project or relevant entities.

- For LNG supply gas - the per gigajoule (GJ) sale price of gas sold by a producer directly, or indirectly through a relevant entity, to an LNG project under all ‘final’ LNG supply gas sales for the period. A ‘final’ LNG supply gas sale is the gas sale between the producer, or a relevant entity for the producer, and the LNG project provided the LNG project is not a relevant entity for either the producer or the reseller.

- For domestic gas - the per gigajoule (GJ) sale price of domestic gas sold by the producer under all ‘final’ domestic gas sales for the period. A ‘final’ domestic gas sale is the first gas sale that does not involve relevant entities.

All sale prices are GST inclusive.

Relevantly, as the purpose of using sales price information is to set a reference price to determine the applicable royalty rate, there is no requirement for any correlation between the volume produced in a return period, which is liable for royalty, and the volume sold, which is only relevant for reference price purposes.

In certain circumstances, sales price will not be used to determine the applicable royalty rate for a producer, and a benchmark price will apply instead as the reference price. This will include those cases where there is no arm’s length sale directly by the producer and it is not possible to trace through a series of sales to derive an arm’s length sales price. This is discussed further under Use of benchmark price as alternative to sales price for each class of petroleum.

An alternative approach for dealing with cases where a producer sells domestic gas to a relevant entity was proposed by the Australian Petroleum Production and Exploration Association (APPEA) during consultation on the volume model. The proposal was for OSR to verify the arm’s length nature of domestic related party gas sales, using standard OECD transfer pricing techniques and in particular, the use of ‘comparable uncontrolled prices’ or CUPs for domestic gas sales. If there was still disagreement between OSR and the producer as to the arm’s length nature of the price, we would recommend that parties enter into independent, binding arbitration for resolution. In the event that binding arbitration is not considered suitable and a substitute price must be used, then that substitute price should only be based on a producer's average domestic sales (and not LNG sales which incorporate additional value-added during liquefaction).
This requirement would effectively continue the current petroleum royalty decision (PRD) process, introducing more complexity and uncertainty into the volume model by requiring a decision to be made about the appropriate sales value to use case by case before a royalty rate could be determined. Incorporating a review mechanism as a fundamental part of this valuation process, whether it be binding arbitration or the review processes to be provided by the TAA, may further delay determination of the applicable royalty rate. This approach is not considered feasible or to achieve the PRR objective of simplifying the current petroleum royalty regime.

However, the approach for determining the domestic gas sales price, and therefore the domestic gas royalty rate, will not have regard to LNG sales.

**Petroleum in liquid form**

As for gas, the relevant royalty rate for crude oil and condensate (referred to in this paper as oil) for a royalty return period will be determined by reference to the sale price of the oil in the period. That is, where the oil sale contract is not between relevant entities, the sale price is the price in the contract entered into by the producer. If the producer and the purchaser are relevant entities, the sale price is that under the first sale contract that does not involve persons who are relevant entities for each other. That is, in the same way as for domestic gas, where possible there will be a tracing through any subsequent transaction or series of transactions after the producer’s sale to obtain an arm’s length sales price for the oil to determine the applicable royalty rate.

As for gas, in limited circumstances the sales price will not be used to determine the applicable oil royalty rate, and a benchmark price will apply instead (see Determining petroleum royalty rate).

### 6. Determining petroleum royalty rate

**Petroleum royalty liability generally**

Petroleum royalty will be determined as follows for each class of petroleum.

- **LNG project gas** – the LNG project gas royalty rate applied to the volume equivalent measured in GJ of LNG project gas produced in a royalty return period

- **LNG supply gas** – the LNG supply gas royalty rate applied to the volume equivalent measured in GJ of LNG supply gas produced in a royalty return period

- **Domestic gas** – the domestic gas royalty rate applied to the volume equivalent measured in GJ of domestic gas produced in a royalty return period

- **Oil** – the oil royalty rate applied to the volume in barrels of oil produced in a royalty return period.

The classification of petroleum into one of the above classes is necessary to determine the royalty rate applicable to the volume of that gas produced during a period which, as noted, may be by use of sales price or a benchmark price applicable to that class of petroleum.
Determining petroleum royalty rate – domestic gas

What is domestic gas?

Domestic gas is all petroleum that is gas at standard temperature and pressure that is:

- sold or transferred to a person who is not a member of an LNG project, but does not include gas sold or transferred as LNG
- flared or vented (existing exemption continues to apply)
- used by the producer for energy generation (used does not include used as feedstock for conversion to LNG)
- disposed of by the producer, other than disposed of as LNG.

For a producer that is not a member of an LNG project, if it is not possible to otherwise determine the classification of gas produced, it is taken to be domestic gas. This would include gas produced and stored in the period. For the classification of gas produced by an LNG project, see What is LNG project gas.

**EXAMPLE 2**

Producer A produces 1,000,000 GJ of CSG during the September quarter. Producer A is not a member of an LNG project. During that period it:

- uses 100,000 GJ for energy production – this is domestic gas
- flares 50,000 GJ- this is domestic gas
- sells 800,000 GJ to a relevant entity that sells it to unrelated industrial users – this is domestic gas
- stores 50,000 GJ – this is taken to be domestic gas.

When lodging the royalty return for the September quarter, Producer A will pay royalty at the domestic gas rate on 1,000,000 GJ of gas.

Comment is sought regarding:
(a) the factors to be taken into account for determining that gas is domestic gas
(b) the inclusion of LPG as domestic gas
(c) any procedural matters to be considered in identifying domestic gas for petroleum royalty purposes.
**Domestic gas royalty rate calculation – general**

The Petroleum and Gas Royalty Regulation will specify the domestic gas royalty rates. The particular rate payable by a producer for a return period will be determined based on a relevant reference price, with the rate increasing as the reference price increases.

The rate payable by a producer for a return period will be determined by reference to:

(a) the sales price per GJ of gas sold by the producer directly, or indirectly through a relevant entity, if the person purchasing the gas is not a relevant entity for either the producer or the producer’s relevant entity reseller

(b) the domestic gas benchmark price prescribed in the Petroleum and Gas Royalty Regulation where:
   (i) the person purchasing the gas is a relevant entity for either the producer or the producer’s relevant entity reseller;
   (ii) information required for determining the royalty rate is not available for a producer when the royalty return is lodged; or
   (iii) a benchmark price decision applies (see Domestic gas royalty rate calculation – use of benchmark price as alternative to sales price).

**Domestic gas royalty rate calculation – use of sales price**

As noted, where possible and appropriate, determination of the royalty rate payable by a producer for domestic gas will be based on the sales price per GJ of domestic gas sold directly, or indirectly by a relevant entity, to a person that is not a relevant entity for either the producer or an intermediary seller.

For the sales price to be used in determining the royalty rate for domestic gas, the final sale must be to a non-relevant entity. Where the first domestic gas sale by a producer is to a relevant entity, the intention is to trace through the transaction(s) to the first sale to a person who is not a relevant entity and use the sales value from that sale. However, as noted in (b)(i) above, if the final sale of gas by a producer is to a relevant entity, this sales price cannot be used to determine the royalty rate and the benchmark price is instead substituted for these sales to derive a deemed price per GJ of domestic gas sold (see formulas below).

The same principles apply for oil (see below).

For determining the applicable domestic gas royalty rate for a return period, the sales price per GJ ($SP$) of domestic gas sold in the period will be determined as follows, and the value for $SP$ is then applied to the tiered domestic gas royalty rates to determine the actual rate payable by the petroleum producer for the period:

\[
SP = \frac{[SA + RES]}{[SV + REV]}
\]
**SA** is, for a return period, the total revenue, expressed in Australian dollars, of domestic gas sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a person who is not a relevant entity for the producer or the reseller.

**SV** is, for a return period, the total volume in GJ of domestic gas sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a person who is not a relevant entity for the producer or the reseller.

**RES** is, for a return period, the deemed sales value of domestic gas sold by the producer during the period if, for the gas, there is no sale directly, or indirectly through a relevant entity for the producer, to a person that is not a relevant entity for the producer or the reseller, worked out as follows:

\[
RES = BR \times REV
\]

**BR** is, for a return period, the domestic gas benchmark price.

**REV** is, for a return period, the total volume in GJ of domestic gas sold by the producer during the period if, for the gas, there is no sale directly, or indirectly through a relevant entity for the producer, to a person that is not a relevant entity for the producer or the reseller.

No costs related to the sale are deductible for determining **SP**. This same principle in relation to costs applies for determining **SP** for LNG project gas, LNG supply gas and oil.

Importantly, where domestic gas is not sold for consideration e.g. it is flared, vented or used, that volume is not taken into account in the above formulas and no value is attributed to it for this purpose either. The domestic gas royalty rate determined using the above formulas is applied to the total volume of domestic gas produced (i.e. including that used and flared, subject to exemptions) for determining royalty liability for the period.

**Domestic gas royalty rate calculation – use of benchmark price as alternative to sales price**

If the only sales of domestic gas made by a producer in a return period are ultimately to a relevant entity, the prescribed domestic gas benchmark price will apply for determining the applicable royalty rate; that is **SP** in the above formula would equal the benchmark price.

Also, if information required for determining the royalty rate is not available for a producer when a royalty return is lodged, the domestic gas benchmark price will apply for determining the royalty payable for all domestic gas produced in the period. That is, the benchmark price will apply instead of **SP** above. This may arise where there are no domestic gas sales in a period and all gas is flared, vented or used.
The Commissioner may also decide that the domestic gas benchmark price will apply for a producer (benchmark price decision) if:

- the producer elects to have the benchmark price apply;
- the domestic gas benchmark price has had to be used for more than one quarterly return period in the last four quarterly return periods (or for two consecutive annual return periods if relevant) because information necessary for determining the royalty rate was not available when the royalty returns were lodged; or
- the Commissioner is satisfied that domestic gas sales and volume information is inadequate, or its use would be inappropriate, for properly determining petroleum royalty payable by a producer having regard to one or both of the following:
  - arrangements between the producer, a relevant entity for the producer and a purchaser of the gas
  - the number of sales of domestic gas, and volume of domestic gas sold, to relevant and non-relevant entities.

A benchmark price decision ensures royalty liability can be properly determined in all cases. Accordingly, it can apply to an earlier return period than the period the decision is made in, and may apply for a stated future period or indefinitely until revoked.

As noted, a producer can elect to have the benchmark price apply, which it may choose to do if compilation of actual sales data will be problematic for instance. If a producer elects to use the benchmark price it is expected it would generally have ongoing application as it is not intended to allow an election to be made period by period. However, the Commissioner may consider a request to revert to use of sales price as the reference price in the future if it is considered appropriate.

These same principles apply for the other classes of petroleum.

Rights of review will be available under the TAA (i.e. objection, and then appeal to the Supreme Court or review by the Queensland Civil and Administrative Tribunal) for the resulting assessment made.

**Determining petroleum royalty rate – LNG project gas**

*What is LNG project gas?*

LNG project gas is all gas produced by an LNG project that is not domestic gas.

For an LNG project, if it not possible to determine whether or not the gas produced is domestic gas, it will be regarded as LNG project gas. This would include where gas is produced and stored during the period.
EXAMPLE 3

XYZ LNG Project produces 1,000,000 GJ of CSG during the September quarter. During that period it:

- uses 150,000 GJ for energy production – this is domestic gas
- flares 50,000 GJ- this is domestic gas
- sells 200,000 GJ to a relevant entity that is not part of the LNG project, that sells it to unrelated industrial users that are not members of an LNG project – this is domestic gas
- stores 100,000 GJ produced in the period – this is LNG project gas
- uses 500,000 GJ for conversion to LNG – this is LNG project gas.

When lodging the royalty return for the September quarter, XYZ LNG Project will pay royalty at the domestic gas rate on the 400,000 GJ of domestic gas produced during the period and at the LNG project gas rate on the remaining volume produced.

If in this example XYZ LNG Project was unable to measure the volume of gas flared, only 350,000 GJ of the CSG produced would be liable for royalty at the domestic gas rate and the remaining volume produced in the period would be liable at the LNG project gas rate.

What is an LNG project?

Broadly an LNG project is an arrangement between a petroleum producer and another person for the supply of gas for producing and selling LNG. This can include:

- one or more petroleum producers (whether or not relevant entities) who operate the tenures together
- one or more persons who are relevant entities for one or more of the petroleum producers and who are involved in the purchase, processing, transportation or liquefaction of the gas, or the storage or sale of the LNG.

To provide certainty, the Commissioner will make a determination about the composition of an LNG project and will notify the petroleum producers of that decision and the date it applies from. The date of effect may be an earlier return period if necessary e.g. to ensure the correct royalty rate applies where the composition of an existing LNG project changes and the change needs to be reflected in a new LNG project decision.

If another person becomes involved with an LNG project in relation to the purchase, processing, transportation or liquefaction of the project’s gas, or the storage or sale of the LNG, the project’s petroleum producers will have an obligation to notify the Commissioner. The same applies if a person ceases to be a member of an LNG project. This will enable the Commissioner to decide if a new LNG project decision is required to include the additional person or exclude the departing person. Failure to notify will be an offence. Notification by one person for the project is sufficient.
EXAMPLE 4

Producer A, Producer B and Producer C are members of a joint venture that produces CSG. They are not relevant entities. Producer A and Producer B incorporate, and hold shares 50:50 in, Transport Co, LNG Co and LNG Sale Co which transport the CSG produced by the joint venture, produce LNG and sell LNG, respectively.

The Commissioner may determine that Producer A, Producer B, Producer C, Transport Co, LNG Co and LNG Sale Co are members of an LNG project for petroleum royalty purposes.

After the LNG project decision is made, a non-tenure holder J Co, who is involved in the joint venture with Producer A, Producer B and Producer C, elects to be treated as a petroleum producer for royalty purposes (see Arrangements for non-tenure holders). As J Co is then taken to be involved in the production of petroleum by the LNG project, Producer A, Producer B and Producer C must notify the Commissioner within 30 days. (Notification by one of them will be satisfactory to meet this obligation.)

As a result, the Commissioner may then determine that Producer A, Producer B, Producer C, J Co, Transport Co, LNG Co and LNG Sale Co are members of an LNG project for petroleum royalty purposes.

Comment is sought regarding:
(a) the factors to be taken into account for determining there is an LNG project and that gas is LNG project gas
(b) any procedural matters to be considered in deciding and notifying the formation of an LNG project or identifying LNG project gas for petroleum royalty purposes.

LNG project gas royalty rate calculation – general

The Petroleum and Gas Royalty Regulation will specify the LNG project gas royalty rates. The particular rate payable by a producer for a return period will be determined based on a relevant reference price as determined below, with the rate increasing as the reference price increases:

(a) by reference to the LNG sales price per GJ of LNG sold directly, or indirectly by a relevant entity for a project member, to a person who is not a member of the LNG project or a relevant entity for any member of the LNG project

(a) by reference to the LNG project gas benchmark price prescribed in the Petroleum and Gas Royalty Regulation where:

(i) the person purchasing the LNG is a member of the LNG project or a relevant entity for any member of the LNG project;

(ii) information required for determining the royalty rate is not available for a producer when the royalty return is lodged; or
(iii) a benchmark price decision applies (see LNG project gas royalty rate calculation – use of benchmark price as alternative to sales price).

**LNG project gas royalty rate calculation – use of sales price**

As noted, determination of the royalty rate payable by a producer for LNG project gas will, where possible and appropriate, be based on the LNG sales price per GJ ($SP$) of LNG sold by the LNG project in the period, determined as follows.

$$SP = \frac{SA + RES}{SV + REV}$$

where –

$SA$ is, for a return period, the total revenue, expressed in Australian dollars, from LNG sold by the LNG project during the period to a person who is not a member of the LNG project and is not a relevant entity for any member of the LNG project

$SV$ is, for a return period, the total volume expressed in GJ of LNG sold by the LNG project during the period to a person who is not a member of the LNG project and is not a relevant entity for any member of the LNG project

$RES$ is, for a return period, the deemed sales value of LNG sold by the LNG project during the period if, for the LNG, there is no sale directly, or indirectly through a relevant entity for a project member, to a person that is not a relevant entity for any member of the LNG project, worked out as follows:

$$RES = BR \times REV$$

$BR$ is, for a return period, the LNG project gas benchmark price

$REV$ is, for a return period, the total volume in GJ of LNG sold by the LNG project during the period if, for the LNG, there is no sale directly, or indirectly through a relevant entity for a project member, to a person that is not a relevant entity for any member of the LNG project

$SA$, $SV$, $RES$ and $REV$ take into account the LNG sold during the period irrespective of where the feedstock gas is sourced from (e.g. some feedstock may be purchased from outside the project) and the time the feedstock gas is produced or purchased.

As noted for domestic gas, no costs related to the sale are deductible for determining $SP$.

The value determined for $SP$ is then applied to the tiered LNG project gas royalty rates to determine the actual rate payable by the petroleum producer for the period.
LNG project gas royalty rate calculation – use of benchmark price as alternative to sales price

If information required for determining the royalty rate is not available when a return is lodged e.g. no LNG sales information has been provided to the producer in time, the prescribed LNG project gas benchmark price will apply for determining the royalty rate payable for all LNG project gas produced in the period. That is, the benchmark price will apply instead of SP above, and this benchmark price will be applied to the tiered LNG project gas royalty rates to determine the actual rate payable by the petroleum producer for the period.

The Commissioner may also decide that the LNG project gas benchmark price will apply for an LNG project (benchmark price decision) if:

- the producer elects to have the benchmark price apply;
- the LNG project gas benchmark price has had to be used for more than one quarterly return period in the last four quarterly return periods (or for two consecutive annual return periods if relevant) because information necessary for determining the royalty rate was not available when the royalty returns were lodged; or
- the Commissioner is satisfied that LNG sales and volume information is inadequate, or its use would be inappropriate, for properly determining petroleum royalty payable by a producer in the LNG project having regard to one or more of the following:
  - arrangements between the producer, a relevant entity for the producer and the LNG seller
  - arrangements between the LNG seller, a relevant entity for the LNG seller and purchasers of the LNG
  - the number of sales of LNG project gas and volume of LNG project gas sold
  - the number of sales of LNG, and volume of LNG sold, by the project to relevant and non-relevant entities.

**EXAMPLE 5**

*LNG Sale Co sells all LNG produced by the XYZ LNG project. LNG Sale Co has failed for the previous and current royalty return periods to provide to the XYZ LNG project producers information about the LNG sales.*

*Having regard to these matters, the Commissioner may make a benchmark price decision, with the result that the royalty rate is determined by reference to the benchmark price rather than the sales of LNG made by LNG Sale Co. The benchmark price decision can apply for a particular period or have no end date stated.*

*An assessment of petroleum royalty liability is made accordingly. The petroleum producers may object to the assessment made.*
Determining petroleum royalty rate – LNG supply gas

What is LNG supply gas?

LNG supply gas is gas that is sold or transferred by a petroleum producer, other than a producer who is a member of an LNG project, directly, or indirectly through a relevant entity, to an LNG project. How the LNG project ultimately uses the gas is not relevant.

Where a producer is a member of an LNG project and sells gas directly or indirectly to another LNG project, the gas is LNG project gas (see What is LNG project gas?).

As the royalty rate payable by a producer in these cases depends on the identity of the entity it sells the gas to, an LNG project must advise each person it purchases gas from that it is an LNG project. It must give this notification to all sellers by the time it first purchases gas from them after 1 October 2020. Failure to do so will be an offence and a separate offence will be committed each time gas is purchased without the notification having been given. However, having given the notification to a particular seller, it is not necessary for the LNG project to provide it again each time there is a purchase from them.

A producer, other than a member of an LNG project, selling gas to a person who has not provided notification to them or an intermediary relevant entity seller that they are an LNG project can treat that gas as domestic gas.

EXAMPLE 6

Producer A sells all of the CSG it produces to a wholly owned subsidiary B Co. Producer A is not a member of an LNG project. B Co sells half of the CSG it purchases from Producer A to XYZ LNG project and half to an unrelated commercial user. XYZ LNG project advises B Co it is an LNG project.

For determining the applicable royalty rate for a return period, Producer A will identify 50% of the volume of CSG produced as being LNG supply gas and 50% of the volume produced as being domestic gas (see What is domestic gas?).

Comment is sought regarding:
(a) the factors to be taken into account for determining that gas is LNG supply gas
(b) any procedural matters to be considered in identifying LNG supply gas for petroleum royalty purposes.

LNG supply gas royalty rate calculation – general

The Petroleum and Gas Royalty Regulation will specify the tiered LNG supply gas royalty rates. The rate payable by a producer for a return period will be determined by reference to:

(b) the sales price per GJ of gas sold directly, or indirectly by a relevant entity, to an LNG project if the member of the LNG project purchasing the gas is not a relevant entity for the producer or the producer’s relevant entity reseller
(c) the LNG supply gas benchmark price prescribed in the Petroleum and Gas Royalty Regulation where:

(iv) the person purchasing the gas is a relevant entity for either the producer or the producer’s relevant entity reseller;

(v) information required for determining the royalty rate is not available for a producer when the royalty return is lodged; or

(vi) a benchmark price decision applies (see LNG supply gas royalty rate calculation – use of benchmark price as alternative to sales price).

**LNG supply gas royalty rate calculation – use of sales price**

As noted, where possible and appropriate, determination of the royalty rate payable by a producer for LNG supply gas will be based on the sales price per GJ of gas sold directly, or indirectly through a relevant entity, to an LNG project that is not a relevant entity for either the producer or the reseller.

For the sales price to be used in determining the royalty rate for LNG supply gas, the final sale must be to a non-relevant entity. As noted in (b)(i) above under LNG supply gas royalty rate calculation – general, where the sale of gas by a producer is directly or indirectly to a member of an LNG project that is a relevant entity, the sales price cannot be used to determine the royalty rate and the benchmark price is instead substituted for these sales to derive a deemed price per GJ of gas sold directly or indirectly to the LNG project (see formulas below).

For determining the applicable LNG supply gas royalty rate for a return period, the sales price per GJ (SP) of LNG supply gas sold in the period will be determined as follows, and the value for SP is then applied to the tiered LNG supply gas royalty rates to determine the actual rate payable by the petroleum producer for the period:

\[
SP = \frac{SA + RES}{SV + REV}
\]

*SA* is, for a return period, the total revenue, expressed in Australian dollars, from LNG supply gas sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a member of an LNG project that is not a relevant entity for the producer or the reseller.

*SV* is, for a return period, the total volume in GJ of LNG supply gas sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a member of an LNG project that is not a relevant entity for the producer or the reseller.

*RES* is, for a return period, the deemed sales value of LNG supply gas, expressed in Australian dollars, sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a member of an LNG project that is a relevant entity for the producer or the reseller, worked out as follows:

\[
RES = BR \times REV
\]
**BR** is, for a return period, the LNG supply gas benchmark price

**REV** is, for a return period, the total volume in GJ of LNG supply gas sold by the producer during the period directly or indirectly to a member of an LNG project that is a relevant entity for the producer or the reseller

**LNG supply gas royalty rate calculation – use of benchmark price as alternative to sales price**

If the only sales of LNG supply gas made directly or indirectly by a producer in a return period are to a relevant entity, the prescribed LNG supply gas benchmark price will apply for determining the applicable royalty rate; that is **SP** in the above formula would equal the benchmark price.

Also, if information required for determining the royalty rate is not available for a producer when a royalty return is lodged, the LNG supply gas benchmark price will apply for determining the royalty payable for all LNG supply gas produced in the period. That is, the benchmark price will apply instead of **SP** above.

The Commissioner may also decide that the LNG supply gas benchmark price will apply for a producer (*benchmark price decision*) if:

- the producer elects to have the benchmark price apply;
- the LNG supply gas benchmark price has had to be used for more than one quarterly return period in the last four quarterly return periods (or for two consecutive annual return periods if relevant) because information necessary for determining the royalty rate was not available when the royalty returns were lodged; or
- the Commissioner is satisfied that LNG supply gas sales and volume information is inadequate, or its use would be inappropriate, for properly determining petroleum royalty payable by a producer having regard to one or both of the following:
  - arrangements between the producer, a relevant entity for the producer and the LNG project
  - the number of sales of LNG supply gas, and volume of LNG supply gas sold, to relevant and non-relevant entities.
Determining petroleum royalty rate – oil

What is oil?

Oil is all petroleum that is a liquid at standard temperature and pressure, and includes crude oil and condensate.\(^4\)

Comment is sought regarding:
(a) the factors to be taken into account for determining that petroleum is oil
(b) any procedural matters to be considered in identifying oil for petroleum royalty purposes.

Oil royalty rate determination

The same principles for determining the royalty rate for oil apply as for domestic gas, including the basis for:

- determining the sales price per GJ (SP) of oil sold in the period to relevant and non-relevant entities
- the use of the oil benchmark price instead of sales price
- making a benchmark price decision.

Specific tiered royalty rates for oil and an oil benchmark price will be prescribed in the Petroleum and Gas Royalty Regulation.

Comment is sought regarding:
(a) the factors to be taken into account for making a benchmark price decision for LNG project gas, LNG supply gas, domestic gas or oil
(b) any procedural matters to be considered in making a benchmark price decision for each class of petroleum.

Access to sales information for determining royalty liability

Where a producer sells petroleum directly to a non-relevant entity, they would be expected to have access to the sales data relevant for determining the royalty rate. However, where a producer sells petroleum to a relevant entity, determination of the royalty rate may require access to information that is within another person’s knowledge and control e.g. for domestic gas this is the relevant entity that makes the final sale. Provision of this information by the relevant entity to the producer is therefore critical to determination of royalty liability and the proper operation of the royalty framework.

\(^4\) It is noted the terms crude oil and condensate are not used in the PGA or PGR but are used under the definition of petroleum in the Petroleum and Gas (General Provisions) Regulation 2017. The particular terms are not defined.
Under section 87 TAA the Commissioner can, by written notice, require a person to provide information or documents for the administration or enforcement of a tax law. The maximum penalty for failure to comply with section 87 TAA is 100 penalty units.\(^5\)

However, section 87 TAA requires the giving of a notice by the Commissioner to an identified person and the provision of the information or documents to the Commissioner, neither of which is practical in these cases. Accordingly, the legislation will include an ongoing obligation for all relevant persons to provide to a petroleum producer the information required for determining the royalty rate applicable for the producer.

Accordingly the following persons will be legislatively required to provide all necessary information to a petroleum producer to enable the producer’s royalty rate to be determined for a period.

1. For a producer that is a member of an LNG project – the LNG project member that sells LNG during the period to a person who is not a member of the LNG project and is not a relevant entity for any member of the LNG project (i.e. to enable the variable $SA$ to be determined for the LNG project gas royalty rate calculation).

2. For a producer that sells LNG supply gas indirectly to an LNG project through a relevant entity – the person that sells the LNG supply gas to the LNG project.

3. For a producer that sells domestic gas or oil to a relevant entity – the person who makes the final sale (see discussion under Petroleum royalty rate calculation – domestic gas).

The required information must be provided to the producer within two weeks of the end of each quarter and in a form suitable to enable the producer’s petroleum royalty liability to be determined on lodgement of the royalty return. Failure to provide the information as required will be an offence with a maximum penalty of 100 penalty units.

\(^5\) Section 121 TAA.
EXAMPLE 7

XYZ LNG Project produces 1,000,000 GJ of CSG during the June quarter. During that period it:

- uses 800,000 GJ of CSG for conversion to LNG, which relevant entity LNG Sale Co sells to unrelated foreign purchasers
- sells 150,000 GJ of CSG to a relevant entity that is not part of the LNG project, Domestic Co, which sells it to industrial users
- flares 50,000 GJ of CSG.

Within two weeks after 30 June, the XYZ LNG Project petroleum producers must be provided the following information:

- by LNG Sale Co - the volume and total revenue of the LNG sold by it during the 1 April – 30 June period
- by Domestic Co - the volume and total revenue of the CSG sold by it during the 1 April – 30 June period.

If LNG Sale Co fails to provide the required information to the producers by the time the June return is lodged, LNG Sale Co commits an offence and the LNG project gas benchmark price will be used to determine the royalty rate for 800,000 GJ of the CSG produced during the period, being LNG project gas.

If Domestic Co fails to provide the required information to the producers by the time the June return is lodged, Domestic Co commits an offence and the domestic gas benchmark price will be used to determine the royalty rate for 200,000 GJ of the CSG produced during the period, being domestic gas.

Comment is sought regarding:
(a) the timeframes for providing to a petroleum producer the sales information necessary for inclusion in its royalty return to enable the applicable royalty rate to be determined
(b) any other procedural matters to be considered in relation to these obligations and use of the information for determining the royalty rate.

Worked examples – determination of petroleum royalty rate

Attachment 2 provides worked examples of how the petroleum royalty rate will be determined, including when use of a benchmark price is required.
7. Arrangements for non-tenure holders

Background

To support adoption of the volume model, particularly the use of sales data to determine the royalty rate, industry requested beneficial reforms to legislatively allow a person who is involved in petroleum production but does not hold any legal interest in the petroleum tenure (non-holder) to elect to be treated as a petroleum producer for all royalty related matters under the Petroleum and Gas Act. Broadly, the proposal is to allow a non-tenure holder to lodge royalty returns and pay royalty as if it is the petroleum producer for its commercial share of petroleum produced from the tenure.

Relevantly for the volume model it would mean that commercially sensitive sales information would not need to be provided by the non-holder to the tenure holder to enable a royalty rate to be determined for a joint venture. Rather, the non-holder would use its sales data to determine the royalty rate applicable to its share of the petroleum produced from the tenure, and pay royalty on that share accordingly. The tenure holder would similarly use its own sales data to determine the royalty rate applicable to its share of the petroleum.

Current legislative obligations for petroleum producers

*Petroleum producer* is defined in schedule 2 of the Petroleum and Gas Act as including the petroleum tenure holder who produces petroleum or for whom it is produced. A petroleum tenure is an authority to prospect or a petroleum lease.

A petroleum producer who produces petroleum is required to pay petroleum royalty and do all things related to meeting this obligation, including lodging returns, paying interest and penalty if royalty is not paid as required, and notifying OSR if royalty has been underpaid. Each tenure holder is jointly and severally liable with the other holders of the tenure for the royalty payable.

Non-holder arrangements

*Election*

To support the volume model, the Petroleum and Gas Act will be amended to allow a person to elect in writing to be treated as a petroleum producer for the payment of royalty and all royalty related matters for a stated petroleum tenure(s). The election must specify the extent to which the person is electing to be deemed a petroleum producer for each tenure e.g. as to 25%, 50% etc. If approved, the non-holder will pay royalty in relation to that proportionate share of petroleum production regardless of any other arrangements that may be in place with the tenure holder, such as gas swaps or banking.

In recognition of the obligations that arise, the making of a non-holder election is voluntary and cannot be compelled by the Commissioner or a tenure holder. However, also in recognition of the obligations that arise and the significant change in the legislative requirements that would otherwise apply, an election is only valid if endorsed by the tenure holder and approved by the Commissioner.

The election will specify a start date from the beginning of a return period, which may be an earlier period but not before 1 October 2020. It may also specify an end date, but need not. The nominated start and end dates will be subject to the Commissioner’s approval.
An election will continue to apply until one of the following happens.

- The election period originally decided by the Commissioner ends.
- The non-holder withdraws the election.
- A tenure holder withdraws support for the election.
- The Commissioner otherwise decides to end the election.

The Commissioner must give notice of a decision to allow, refuse or end an election, together with reasons for the decision as appropriate.

OSR will publish further information about how to make or revoke an election.

**Rights and obligations**

From the election start date the non-holder is taken to be a petroleum producer for section 590 Petroleum and Gas Act and to produce the proportion of petroleum stated in the election for the relevant tenure. Relevantly, the election applies only for royalty matters under the Petroleum and Gas Act and does not in any way affect anything relating to the tenure i.e. it does not newly create a legal interest in the tenure for the non-holder or affect any interest the non-holder may be taken to have in another way.

From the election start date the non-holder must lodge royalty returns for its share of the petroleum and pay all royalty assessed. In determining the royalty payable, the volume of petroleum produced and the applicable rate are determined as though the non-holder is the producer of that petroleum. Interest and penalty will apply if the non-holder fails to pay its royalty liability on time or does not properly disclose its correct liability and a reassessment increasing liability is made.

Although these non-holder arrangements will allow a person to voluntarily assume responsibility for meeting royalty obligations that would otherwise apply to the tenure holder, revenue protection measures will remain to ensure all royalty payable for the tenure is paid. As the non-holder does not actually hold the tenure despite being deemed a petroleum producer for royalty purposes, the tenure holder remains liable for all royalty for the tenure if the non-holder defaults. Where more than one person holds a tenure each holder is jointly and severally liable for unpaid royalty. In addition, the tenure holder would not be permitted to transfer all or part of the tenure if any royalty payable by the non-holder remains unpaid. In that case, the tenure holder may pay any outstanding royalty to enable the transfer to occur.

Other royalty related rights and obligations will apply to the non-holder in the same way as for the tenure holder.

- The non-holder will have rights of review under the TAA for assessments made.
- The non-holder may be prosecuted for an offence if it makes a false or misleading statement, provides a false or misleading document or information, or fails to give a notice as required e.g. a notice that royalty was incorrectly assessed.
- The non-holder must keep records for determining its royalty liability.

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The ending of an election does not affect any obligations incurred during the election period, any actions that could be taken by the Commissioner against the non-holder arising during the election period, or any liability for royalty arising during the election period (including where that liability crystallises after the election is withdrawn, such as following an audit). However, as noted, if the non-holder fails to pay any royalty outstanding, the tenure holder remains liable for it.

8. Lodgement of returns

Return lodgement arrangements generally

Currently the Petroleum and Gas Act requires a petroleum producer to:

- lodge a quarterly royalty return for each period in which petroleum is produced, disposed of or stored, and pay the royalty on the return due date
- lodge an annual royalty return if royalty is or may be payable for the annual period
- pay any difference between the annual return liability and the amount payable for the quarterly returns on the annual return due date.

The annual return is necessary because wellhead value, and therefore the actual petroleum royalty liability, cannot be properly determined until the end of the annual period when all sales have been reconciled and all deductions, including depreciation, quantified. The annual return therefore reconciles actual annual royalty liability and the royalty paid for the quarterly returns.

Annual returns can be currently lodged on either a calendar year or financial year basis depending on the producer's preference. This recognises that proper determination of the depreciation deduction for wellhead value purposes in particular is usually only possible once a producer's annual financial statements are prepared, with some producers preparing these statements on a calendar year and some on a financial year basis.

Changes to petroleum royalty return lodgement arrangements were proposed under the RAM program and consultation on that framework has been undertaken. On adoption of the volume model, further simplification of those proposed arrangements is possible to reflect that annual reconciliation of royalty liability will no longer be necessary. Accordingly, from 1 October 2020 petroleum royalty returns will be lodged for an operation as follows.

- An operation that has at least one petroleum lease will lodge quarterly returns, with lodgement of returns being mandatory regardless of liability. No annual return is required.
- An operation with only authorities to prospect and no petroleum leases must lodge an annual return, including if no royalty is payable for the period. All annual returns will be lodged on a financial year basis as there is no longer any need to claim annually determined deductions. However the Commissioner can require lodgement of quarterly returns instead of the annual return if satisfied it would be appropriate or if the producer requests it.
These new return lodgement arrangements do not affect who lodges a return. Accordingly, a petroleum operation lodging a return for particular petroleum tenures will continue to lodge returns for those tenures, subject to any election made by a non-tenure holder to be deemed to be a petroleum producer for the tenures (see *Arrangements for non-tenure holders*). Also, as is currently the case, royalty liability will be determined for the operation. This means that determination of the royalty rate using sales price will be done at the operation level to determine the appropriate royalty rate for the operation.

**Transitional return lodgement arrangements**

**Quarterly and annual returns – pre-commencement liabilities**

As noted, the new return framework applies to returns lodged for periods starting on or after 1 October 2020.

Quarterly returns for the period ending 30 September 2020 will therefore be lodged on the wellhead value basis by 30 October 2020 as is currently the case. However, special arrangements will be necessary to allow annual returns to be lodged on the wellhead value basis for liabilities up to 30 September 2020 to reconcile the final wellhead value to that date, prior to producers then moving to quarterly return obligations only or annual return lodgement obligations only. The following special transitional arrangements for shorter ‘annual’ periods will therefore be necessary to finalise wellhead value liabilities arising up to that time.

- **Financial year lodgers:** A transitional annual return for the period 1 July 2020 to 30 September 2020 will be due by 31 December 2020. It will include all petroleum produced during that period, with liability determined on the wellhead value basis, and will reconcile the actual liability for the period and the September quarterly return liability.

- **Calendar year lodgers:** A transitional annual return for the period 1 January 2020 to 30 September 2020 will be due by 31 December 2020. It will include all petroleum produced during that period, with liability determined on the wellhead value basis, and will reconcile the actual liability for the period and the March, June and September quarterly return liabilities.

**Petroleum produced but not disposed of before commencement**

As noted, the volume model applies to all petroleum produced from 1 October 2020. Returns lodged for a period commencing from 1 October 2020 are to include only this petroleum.

The Petroleum and Gas Act imposes royalty on all petroleum produced by a petroleum producer; that is royalty liability is incurred on production. However, for paying the royalty, the Petroleum and Gas Royalty Regulation currently requires the petroleum be included in the return for the period it is disposed of.

Where petroleum is produced but not disposed of by 1 October 2020, the current return arrangements would require this petroleum to be included in a post 1 October 2020 return. However, as noted these returns will be lodged on the volume basis, which does not apply to pre 1 October 2020 production.

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7 31 October is not a business day.
Therefore, to ensure royalty is properly payable once the new arrangements commence, this petroleum will instead need to be included in the September 2020 quarterly return and royalty paid on its wellhead value. If the petroleum has not been disposed of by 30 October 2020 when the September quarterly return is due, and royalty liability cannot be properly quantified at that time, the actual liability should be reconciled when the annual return for the period to 30 September 2020 is lodged on 31 December 2020.

An issue was raised during consultation regarding take-or-pay arrangements and determination of royalty liability on adoption of the volume model. The concern was the volume model could result in double payment of royalties on the one volume of gas where gas is sold under a take-or-pay arrangement before 1 October 2020, at which time royalty is payable on the wellhead value basis, and is delivered at a later date when the volume model applies.

However, as noted above, the design of the volume model, which ensures royalty is payable on first production, and the effect of the transitional arrangements, which ensure royalty is payable on the wellhead value basis if it is produced before 1 October 2020, should mean that take-or-pay arrangements do not give rise to any issues on commencement of the volume model.

**EXAMPLE 8**

*ABC Co is currently lodging on a calendar year basis. It produces petroleum on 30 September 2020, which it sells on 10 November 2020. Under transitional arrangements to support implementation of the volume model, the petroleum is required to be included in the September quarterly return due on 30 October 2020. However, as the wellhead value of the petroleum cannot be properly determined when the quarterly return is lodged, ABC Co will include the petroleum in the annual return for the 2020 calendar year which, under the transitional arrangements, is due on 31 December 2020, and will pay any shortfall then.*

**First annual return post commencement**

For those producers who will be lodging quarterly returns under the new returns framework (i.e. those with a petroleum lease), this will commence for the December 2020 quarterly return and all liability for that and future quarterly return periods will be determined on the volume basis. There will be no further need to lodge annual returns for petroleum royalty liability arising from that time.

For those producers who will only be lodging annual returns (i.e. those with only authorities to prospect), the first annual return under the new framework will be lodged for the period from 1 October 2020 to 30 June 2021. This return will be due on 30 September 2021. All liability for that and future annual return periods will be determined on the volume basis.

Comment is sought regarding whether:

(a) these transitional return arrangements will appropriately accommodate all instances where petroleum has been produced but not disposed of prior to 1 October 2020

(b) any other issues need to be considered for the transitional return arrangements.
9. Petroleum royalty decisions

Currently the Minister may make a PRD under the Petroleum and Gas Royalty Regulation to determine components of wellhead value, including the commercial value of petroleum and the value of statutory deductions. The PRD may apply for a stated period.

On commencement of the volume model for petroleum produced from 1 October 2020, there will no longer be any need for a PRD for that petroleum. Accordingly, the PRD provisions will cease to apply for this petroleum and the operation of existing PRDs will cease for petroleum produced post commencement despite any statement to the contrary in the PRD.

However a PRD may still be required for liabilities arising pre-commencement and the PRD provisions will continue to operate to this extent. This means that from 1 October 2020 the Commissioner may make a PRD for petroleum produced before 1 October 2020 and may amend a PRD relating to pre commencement liabilities. The RAM program will provide review rights for any PRD or amendment of a PRD made from 1 October 2020.

Any legislative obligations imposed in relation to a PRD will continue to apply. For instance, if a stated factor for a PRD has changed and the change is relevant for a period covered by the PRD, the obligation for the producer to notify the Commissioner within 60 days will continue. This will enable the Commissioner to consider whether the PRD should be amended for pre commencement liabilities.8

10. Other issues

Indexation of royalty rate tiers

During consultation industry raised for consideration whether the royalty rate tiers should be adjusted by reference to an appropriate benchmark price such as CPI to avoid perceived ‘bracket creep’.

When announcing the outcome of the PRR and adoption of the volume model from 1 October 2020, the Treasurer and Minister for Infrastructure and Planning also announced the government’s intention not to adjust the royalty rates for five years.

The appropriate basis for setting the petroleum royalty rate after that time, including the relevance of indexation of the rate tiers, will be a matter for government.

Private royalty arrangements

An issue was raised during consultation regarding how a move away from wellhead value to a volume model for imposing petroleum royalty may impact existing contracts that provide for the payment of a private royalty. The issue relates to the fact some private royalty arrangements may require determination of an arm’s length value of petroleum and, for this purpose, some reliance may have been placed on the commercial value determined for petroleum royalty purposes under the wellhead value method.

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8 See s.148G Petroleum and Gas Royalty Regulation.
The extent to which detailed royalty information is required to support these private royalty arrangements is unclear. However, the provision of this information to a private royalty recipient is a matter for the royalty payer as OSR has no legislative basis for disclosing this information, and is in fact prohibited from doing so without the royalty payer’s consent.

That is, the parties to a private royalty arrangement would need to contractually specify how the value of petroleum is to be determined and to have arrangements for confirming that value without reliance on information held by OSR. This could be based on the same methodology currently used to determine the royalty value, but it is a matter for the parties as to how this is given effect, verified and enforced.

Ultimately, therefore, whether or not appropriate petroleum valuation information is provided to a private royalty recipient is not affected by the petroleum royalty regime in effect, and adoption of the volume will not affect this.

**Grouping of corporate entities**

Currently petroleum producers operating multiple tenures may lodge a royalty return on an operations basis. These arrangements, which apply under an administrative arrangement, allow royalty to be determined for the operation.

During PRR consultation, an issue was raised regarding how corporate groups account for petroleum royalty where operations are managed on a portfolio basis. It was requested that consideration be given to allowing revenues and production volumes to be determined for petroleum royalty purposes on a corporate group basis if the volume model is implemented. This issue is outside the scope of the PRR.
## SUMMARY OF DEFINITIONS

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| Domestic gas             | Petroleum that is gas at standard temperature and pressure that is:  
- sold or transferred to a person who is not a member of an LNG project, but does not include gas sold or transferred as LNG  
- flared or vented  
- used by the producer other than as feedstock for conversion to LNG  
- disposed of by the producer, other than disposed of as LNG. For a producer that is not a member of an LNG project, if it is not possible to determine the classification of gas produced, it is domestic gas. |
| LNG project              | An arrangement between a petroleum producer and another person for the supply of gas for producing and selling LNG, and includes:  
- one or more petroleum producers (whether or not relevant entities) who operate the tenures together  
- one or more persons who are relevant entities for one or more of the petroleum producers and who are involved in the purchase, processing, transportation or liquefaction of the gas, or the storage or sale of the LNG. |
| LNG project gas          | Petroleum that is gas at standard temperature and pressure which is produced by an LNG project and is not domestic gas. For an LNG project, if it is not possible to determine whether or not the gas produced is domestic gas, it will be regarded as LNG project gas. |
| LNG supply gas           | Petroleum that is gas at standard temperature and pressure which is sold or transferred by a petroleum producer, other than a producer who is a member of an LNG project, directly or indirectly through a relevant entity to an LNG project. |
| Oil                      | Petroleum that is liquid at standard temperature and pressure, and includes crude oil and condensate. |
| Produced (s.15 Petroleum and Gas Act) | Petroleum is *produced* when it is—  
(a) recovered to ground level from a natural underground reservoir in which it has been contained; or  
(b) released to ground level from a natural underground reservoir from which it is extracted. |
| Relevant entity (s.148A Petroleum and Gas Royalty Regulation) | For a petroleum producer, means—  
(a) for a petroleum producer that is a corporation—  
(i) an associated entity of the corporation within the meaning of the Corporations Act, section 50AAA; or  
(ii) a related entity of the corporation within the meaning of the Corporations Act, section 9, definition related entity; or  
(iii) a related party of the corporation within the meaning of the Corporations Act, section 228; or  
(b) for a petroleum producer who is an individual—a related person of the individual within the meaning of the *Duties Act 2001*, section 61, other than section 61(1)(d) of that Act. |
EXAMPLES – DETERMINATION OF ROYALTY RATES

WORKED EXAMPLE 1

FACTS

ABC LNG Project produces 900,000 GJ of CSG and 100,000 GJ of natural gas during the June quarter. During this period:

- it uses 750,000 GJ of gas for conversion to LNG
- LNG Sale Co, a relevant entity, sells 700,000 GJ of LNG produced by the project for $7M to unrelated foreign purchasers
- it sells 150,000 GJ of gas to Domestic Co, a relevant entity but not an LNG project member
- Domestic Co sells 200,000 GJ of gas for $1M to unrelated industrial users
- it flares 50,000 GJ of gas.

An LNG project decision has been made by the Commissioner for ABC LNG Project. The members of the ABC LNG Project are LNG Sale Co, Domestic Co, and Producer A, Producer B and Producer C who hold the tenures for the project.

LNG Sale Co provides information to the project’s producers regarding the volume and total revenue of the LNG sold by it during the June quarter. Domestic Co provides information to the producers regarding the volume and total revenue of the gas sold by it during the June quarter.

DETERMINATION OF ROYALTY RATE

Domestic gas rate determination

For determining the applicable royalty rate for the domestic gas produced by ABC LNG Project during the period, it is necessary to determine \( SP \) as follows:

\[
SP = \frac{1,000,000 + 0}{200,000 + 0} = \$5/GJ
\]

where:

\( SP \) is, for the return period, the sales price per GJ of domestic gas sold in the period, worked out as follows:

\[
SP = \frac{SA + RES}{SV + REV}
\]
**SA** is, for the return period, the total revenue, expressed in Australian dollars, from domestic gas sold during the period by the producer directly, or indirectly through a relevant entity, to a person who is not a relevant entity for either the producer or the reseller.

**SV** is, for the return period, the total volume in GJ of domestic gas sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a person who is not a relevant entity for either the producer or the reseller.

**RES** is, for the return period, the deemed value of domestic gas sold by the producer during the period if, for the gas, there is no sale directly, or indirectly through a relevant entity for the producer, to a person that is not a relevant entity for either the producer or the reseller, worked out as follows:

\[ RES = BR \times REV \]

**BR** is, for the return period, the domestic gas benchmark price.

**REV** is, for the return period, the total volume in GJ of domestic gas sold during the period by the producer if, for the gas, there is no sale directly, or indirectly through a relevant entity for the producer, to a person that is not a relevant entity for either the producer or the reseller.

As all sales of domestic gas are to persons who are not relevant entities, only **SA** and **SV** are relevant for the formula; **RES** and **REV** are irrelevant.

The value for **SP** of $5/GJ is then applied to the tiered domestic gas rates (as prescribed), and the result applied to the volume of domestic gas produced during the June quarter i.e. 200,000GJ (150,000 GJ + 50,000 GJ) to determine the royalty payable for that volume of domestic gas produced during the period.

**LNG project gas rate determination**

For determining the applicable royalty rate for the LNG project gas produced by ABC LNG Project during the period, it is necessary to determine **SP** as follows:

\[ SP = \frac{7,000,000 + 0}{700,000 + 0} = \$10/GJ \]

where:

**SP** is, for the return period, the LNG sales price per GJ of LNG sold by the LNG project in the period, worked out as follows:

\[ SP = \frac{[SA + RES]}{[SV + REV]} \]

**SA** is, for the return period, the total revenue, expressed in Australian dollars, from LNG sold by the LNG project during the period to a person who is not a member of the LNG project and is not a relevant entity for any member of the LNG project.
**SV** is, for the return period, the total volume expressed in GJ of LNG sold by the LNG project during the period to a person who is not a member of the LNG project and is not a relevant entity for any member of the LNG project.

**RES** is, for a return period, the deemed sales value of LNG sold by the LNG project during the period if, for the LNG, there is no sale directly, or indirectly through a relevant entity for a project member, to a person that is not a relevant entity for any member of the LNG project, worked out as follows:

\[ RES = BR \times REV \]

**BR** is, for a return period, the LNG project gas benchmark price.

**REV** is, for a return period, the total volume in GJ of LNG sold by the LNG project during the period if, for the LNG, there is no sale directly, or indirectly through a relevant entity for a project member, to a person that is not a relevant entity for any member of the LNG project.

The value for **SP** of $10/GJ is then applied to the tiered LNG project gas rates (as prescribed), and the result applied to all gas produced by the project during the June quarter that is not domestic gas i.e. 800,000 GJ (1,000,000 GJ – 200,000 GJ) to determine the royalty payable for the LNG project gas produced during the period.

For determining the volume of LNG project gas produced, it is noted that not all of the gas produced during the period was used for conversion to LNG, sold as domestic gas or flared. Any volume of gas produced by an LNG project that cannot be identified as domestic gas is taken to be LNG project gas.
WORKED EXAMPLE 2

FACTS

ABC LNG Project produces 1,000,000 GJ of CSG during the June quarter return period. It also purchased 500,000 GJ of CSG for $2M from an unrelated producer, S Co, on 31 March to supplement the CSG volumes available for conversion to LNG during the June quarter. S Co is not a member of an LNG project.

During the June quarter:

- 1,300,000 GJ of CSG is used for conversion to LNG (800,000 GJ produced by the project and 500,000 GJ purchased)
- LNG Sale Co, a relevant entity, sells 1,000,000 GJ of LNG produced by the project for $11M to unrelated foreign purchasers
- It sells 150,000 GJ of CSG to Domestic Co, a relevant entity but not an LNG project member
- Domestic Co sells 200,000 GJ of CSG for $1M to unrelated industrial users
- It flares 50,000 GJ of CSG.

DETERMINATION OF ROYALTY RATE

Domestic gas rate determination

For determining the applicable royalty rate for the domestic gas produced by ABC LNG Project during the period, SP is determined in the same way as for Worked Example 1.

If however Domestic Co failed to provide to the ABC LNG Project the information required about its domestic gas sales for the period before the royalty return is lodged on 31 July, there is no domestic gas sales information to determine SP for the domestic gas royalty rate calculation. Accordingly, the domestic gas benchmark price would be used to determine the applicable royalty rate for the ABC LNG Project for the June quarter, and this rate would be applied to 200,000 GJ of the CSG produced during the June quarter to determine the royalty payable for the domestic gas produced during the period.

Use of the benchmark price for domestic gas does not affect determination of the LNG project gas royalty rate by reference to the LNG sales data (see below).
LNG project gas rate determination

For determining the applicable royalty rate for the LNG project gas produced by ABC LNG Project during the period, \( SP \) is determined as follows:

\[
SP = \frac{11,000,000 + 0}{1,000,000 + 0} = \$11/GJ
\]

The value for \( SP \) of $11/GJ is then applied to the tiered LNG project gas rates (as prescribed), and the result applied to the remaining volume of CSG produced by the LNG project during the period i.e. 800,000 GJ to determine the royalty payable for the LNG project gas.

The volume of LNG sold by the project reflects that feedstock CSG has been purchased by the project. That LNG volume and total sales revenue is taken into account for determining \( SP \) in the above formula and is used to determine the royalty rate payable on the LNG project gas produced by the ABC LNG Project i.e. 800,000 GJ as noted.

No royalty is payable by the ABC LNG Project for the 500,000 GJ of CSG purchased from S Co as S Co is the liable producer (see below).

LNG supply gas rate determination

Royalty is payable by S Co for the 500,000 GJ of CSG which S Co produced and sold to ABC LNG Project in the March quarter. This gas is LNG supply gas. As the CSG sale is to an LNG project that is not a relevant entity, the volume and revenue from the sale is taken into account for determining \( SP \) for S Co the March quarter as follows (assuming this is the only sale of LNG supply gas made by S Co in the period):

\[
SP = \frac{2,000,000 + 0}{500,000 + 0} = \$4/GJ
\]

where:

\( SP \) is, for the return period, the sales price per GJ of LNG supply gas sold in the period, worked out as follows:

\[
SP = \frac{SA + RES}{SV + REV}
\]

\( SA \) is, for the return period, the total revenue, expressed in Australian dollars, from LNG supply gas sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a member of an LNG project that is not a relevant entity for either the producer or the reseller

\( SV \) is, for the return period, the total volume in GJ of LNG supply gas sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a member of an LNG project that is not a relevant entity for either the producer or the reseller
**RES** is, for the return period, the deemed sales value of LNG supply gas, expressed in Australian dollars, sold by the producer during the period directly, or indirectly through a relevant entity for the producer, to a member of an LNG project that is a relevant entity for either the producer or the reseller, worked out as follows:

\[ RES = BR \times REV \]

**BR** is, for the return period, the LNG supply gas benchmark price

**REV** is, for the return period, the total volume in GJ of LNG supply gas sold by the producer during the period directly or indirectly to a member of an LNG project that is a relevant entity for either the producer or the reseller

If any other LNG supply gas was sold by S Co during the March quarter it would also be included in the above formulas as appropriate.

If the sale of the 500,000 GJ of CSG to the ABC LNG Project had instead been made on 1 April, the sales information would be included for determining the LNG supply gas royalty rate for LNG supply gas produced by S Co during the June quarter.

If S Co and the ABC LNG Project were relevant entities, the volume and revenue from the sale of the 500,000 GJ of CSG to the LNG project would not be taken into account for SA or SV in the above formula. Rather the benchmark price would be applied to the volume sold to derive **RES** and **REV** for the formula and this would then be used to determine the LNG supply gas royalty rate payable by S Co for the gas produced. If S Co made no other sales of LNG supply gas during the period, the result would be that the royalty rate payable by S Co for the period would be based on the benchmark price.