Updated Projections of Gas and Electricity Used in LNG

Prepared for

Australian Energy Market Operator

Lewis Grey Advisory

LG004 | Final Public Report

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1	29/09/15	First draft	R Lewis
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Contents

Disclaimer

This report has been prepared solely for the Australian Energy Market Operator for the purpose of assessing gas and electricity use in LNG production. Lewis Grey Advisory bears no liability to any party (other than specifically provided for in contract) for any representations or information contained in or omissions from the report or any communications transmitted in the course of the project.

Executive summary

Terms of reference

The Australian Energy Market Operator (AEMO) has engaged Lewis Grey Advisory (LGA) to provide the following consultancy services:

1. Delivery of an updated report and dataset relating to historical data and forecasts of gas and electricity consumption (annual and maximum/peak daily) related to LNG export for the next 25 years (2014-15 to 2040-41) under various scenarios and conditions.
2. Delivery of an update to the report and to be delivered by 30 September 2015.
3. Provide updates to the forecast triggered by major events as requested by AEMO.

These deliverables should be developed using the Consultant's analysis and market intelligence as well as direct consultation with industry stakeholders. It is imperative that clear reasoning is provided where the Consultant's forecasts differ from information provided by stakeholders.

The deliverables must be suitable for publishing on the AEMO website. The forecasts themselves will be used as inputs into the NEFR and NGFR. More specifically, this project involves:

- Industry (LNG) stakeholder consultation (for report and mid-year update):
  - a. Review of templates/questionnaires for industry stakeholders
  - b. Assessing stakeholder responses to questionnaires (if available) and working with AEMO on any required follow-up with industry stakeholders.
- Internal AEMO stakeholder consultation through the engagement.
  - a. Working with key AEMO stakeholders to answer questions on the deliverables and making appropriate revisions to draft deliverables based on AEMO feedback.
  - b. A transfer of knowledge to members of AEMO's Energy Forecasting team and other teams as appropriate regarding the LNG sector consumption modelling.
- Development of a report and mid-year update, suitable for publishing on the AEMO website, detailing forecasts of LNG production (in million tonnes per annum (Mtpa)) from eastern and south-eastern Australia as well as the gas and electricity consumption associated with this production. Key aspects to be addressed as part of this document are described in Section 2.2.
- Provision of an Excel database(s) proving data underpinning any chart, figure and/or forecasts presented in the report and the mid-year update.
- Provide updates to the forecasts triggered by major events as requested by AEMO on an ad-hoc basis

This report

This report fulfils the September update requirement of item 2) outlined in the Terms of Reference (the first draft was delivered on 29th September). The public version of the initial report was published by AEMO on its website in June 2015. Items 1) and 3) have been complied with separately.

As in the initial report the required forecasts of LNG production and the gas and electricity usage associated with this production have not been derived from information provided by stakeholder questionnaires, as anticipated in the terms of reference, but are the result of modelling undertaken by LGA based largely on information in the public domain, much of it provided by the stakeholders on their websites. Use of confidential material provided by stakeholders is limited to details of production facility capacities and this material and the results derived from it have been redacted from this report.

This report documents only the changes made since the initial report, with which it is assumed the reader is familiar. The changes are generally minor except in relation to grid-supplied electricity usage and reflect more detailed LNG project information becoming available rather than actual changes to the projects. The High Scenario also reflects variations to levels of production by the first six LNG trains and the timing of the 7th train.

Summary of findings

Queensland Curtis LNG (QCLNG) commenced exports from its first LNG train on Curtis Island, near Gladstone, in January 2015. This train was declared "commercial" (delivering LNG cargoes according to contract) and QCLNG's second train became operational in July. Gladstone LNG (GLNG) started LNG production in late-September 2015 and Australia Pacific LNG (APLNG) is scheduled to follow in the final quarter of 2015. Both of these projects' second trains are expected to start up in the first half of 2016.

The six LNG trains are each capable of delivering about 3.9 to 4.5 million tonnes of LNG per year when operating at their nameplate capacities. A fourth major project, that of Arrow Energy, was cancelled as a stand-alone project earlier this year and Arrow has yet to indicate how it will try to monetise the value of its gas reserves. Using the gas in a third train at one of the existing projects or another, smaller, project is a widely canvased option. Arrow's 50% owner, Shell, is in the process of taking over BG Group, the majority owner of QCLNG.

The purpose of this study is to provide AEMO with consistent estimates of the gas supply required for export, including gas used in the supply chain, and grid-supplied electricity usage in the supply chain. The relevant estimates are used in the preparation of AEMO's National Electricity Forecast Report (NEFR) and National Gas Forecast Report (NGFR), ensuring consistency in regard to LNG assumptions in these two reports.

The key elements of the study are:

1. Three scenarios concerning the overall levels of exports.
2. A methodology for estimating electricity and gas used in the LNG supply chain
3. Projections of electricity and gas used in LNG export based on applying the methodology to the scenarios.

Since the data for the initial report was finalised, in early March 2015, the LNG project operators have not notified external stakeholders of any changes to the projects other than short delays to the start of LNG production by GLNG and APLNG. Consequently the Base Scenario is as in the initial report but incorporating these delays.

Likewise LGAs' methodology for estimating electricity and gas used in the LNG supply chain remains essentially the same but with updated parameter estimates. However further information about the projects upstream energy use has been obtained through AEMO's discussions with LNG project representatives and an APLNG report released through its regulatory approval process[1], referred to as Reference 1 in the remainder of the report.

These factors contribute to a small increase in LGAs' estimates of gas used in gas liquefaction and gas production and a material decrease in LGA's estimates of grid-supplied electricity used in gas production.

[1] Upstream Basis of Design, APLNG Upstream Project. Attachment 2 to APLNG application to construct Talinga-Condabri Interconnect Pipeline. Available at www.dilgp.qld.gov.au

Projections

Updated total LNG export projections are presented in Figure E 1, together with the equivalent projections from the initial 2015 report (dashed lines). The Base and Low scenarios are unchanged in the long run while the High scenario is 3.4% higher as production at the six existing trains is now set at 110% of the Base scenario instead of plant capacity. Export levels range from 20 Mtpa in the Low scenario to over 30 Mtpa in the High scenario. However each scenario takes slightly longer to ramp up owing to later start up at GLNG and APNG than assumed in the initial report and the assumed delay to the 7th train.

Figure E 1 Total LNG export projections

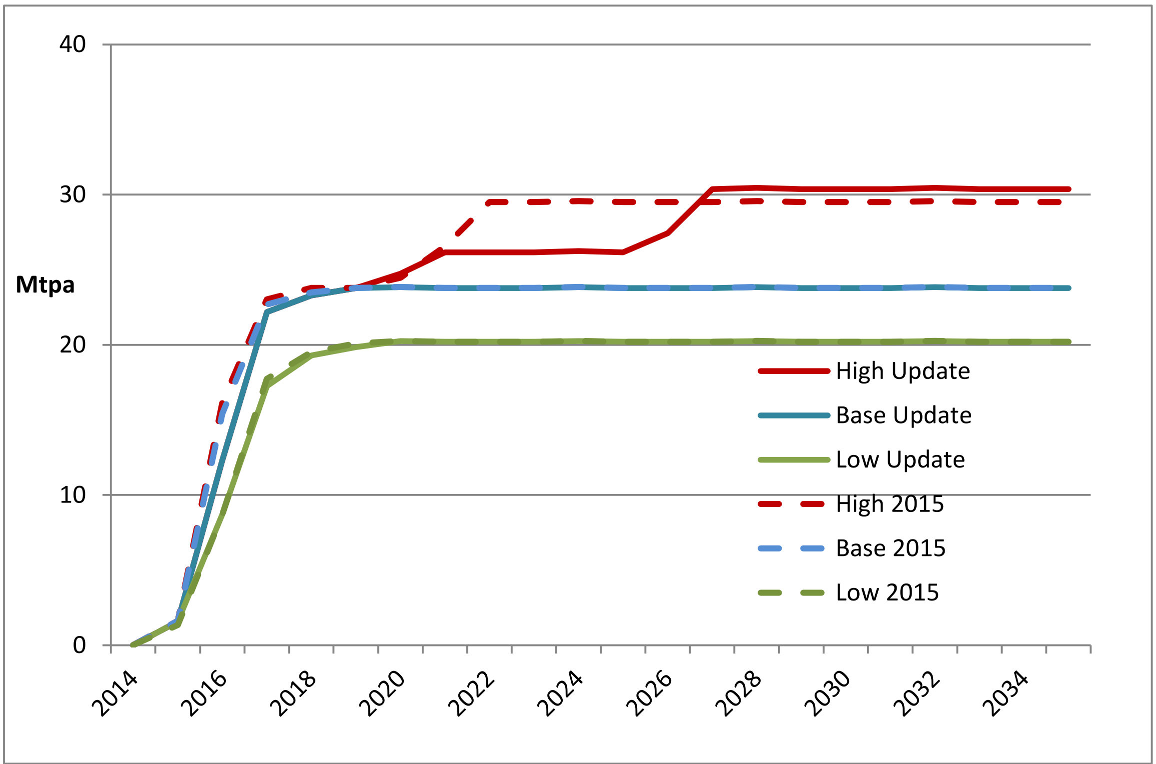


Figure E 2 and Figure E 3 show the total gas usage and total grid electricity usage respectively. The energy usage figures include estimates of energy usage in third party gas production.

For gas usage, the Base and Low scenario updated projections are approximately 7% higher than the initial 2015 projections due to the additional gas usage assumed at QCLNG and APLNG electrically driven upstream plant (refer to section 3.6.4), slightly offset by lower usage in liquefaction. The High scenario is 10% higher after 2026 owing to the additional 3.4% of LNG production. In energy terms the increases in gas usage range from 7 PJ per year in the Low Scenario to 15 PJ per year in the High Scenario.

The updated electricity usage projections are each approximately 20% lower than the equivalent initial 2015 projections, mainly due to the revised estimates of the electricity requirements for gas compression (refer to section 3.6.4). In energy terms the reductions in electricity usage range from 1,600 GWh per year in the Low Scenario to 2,200 GWh per year in the High Scenario. The potential for material revisions to these estimates was foreshadowed in the initial report.

Figure E 2 Total gas used in liquefaction and production

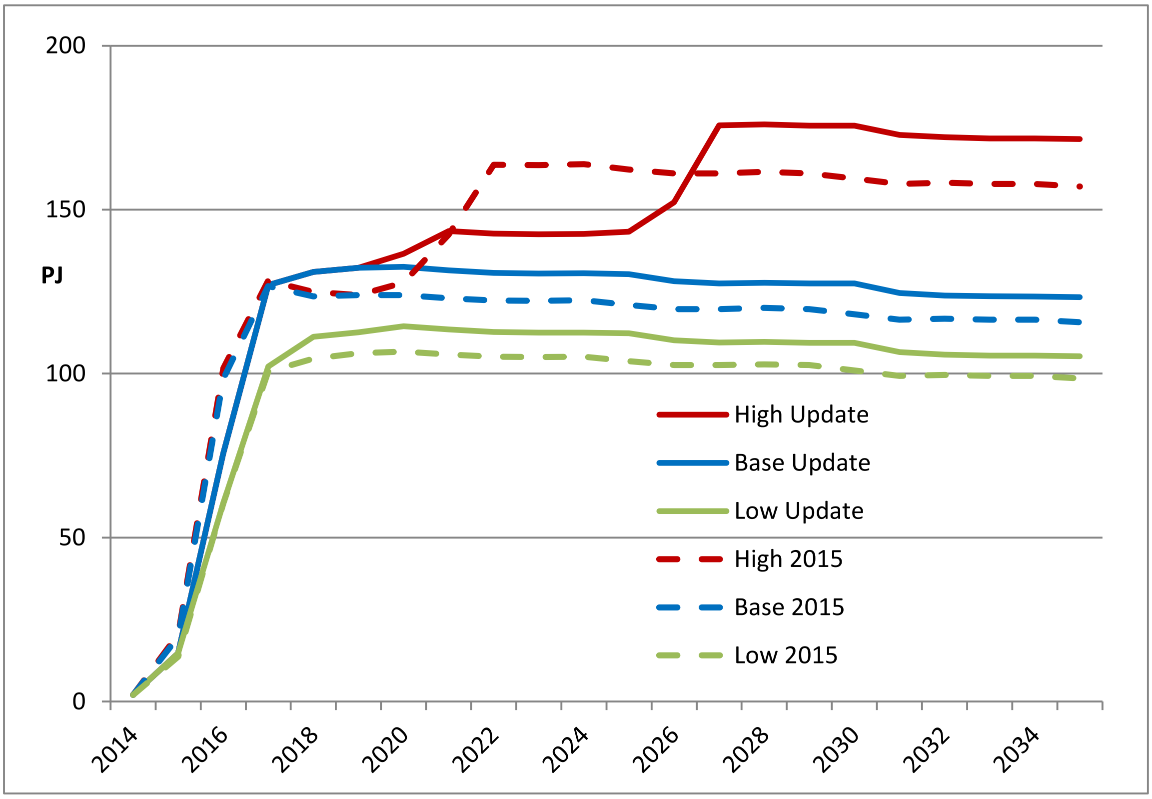
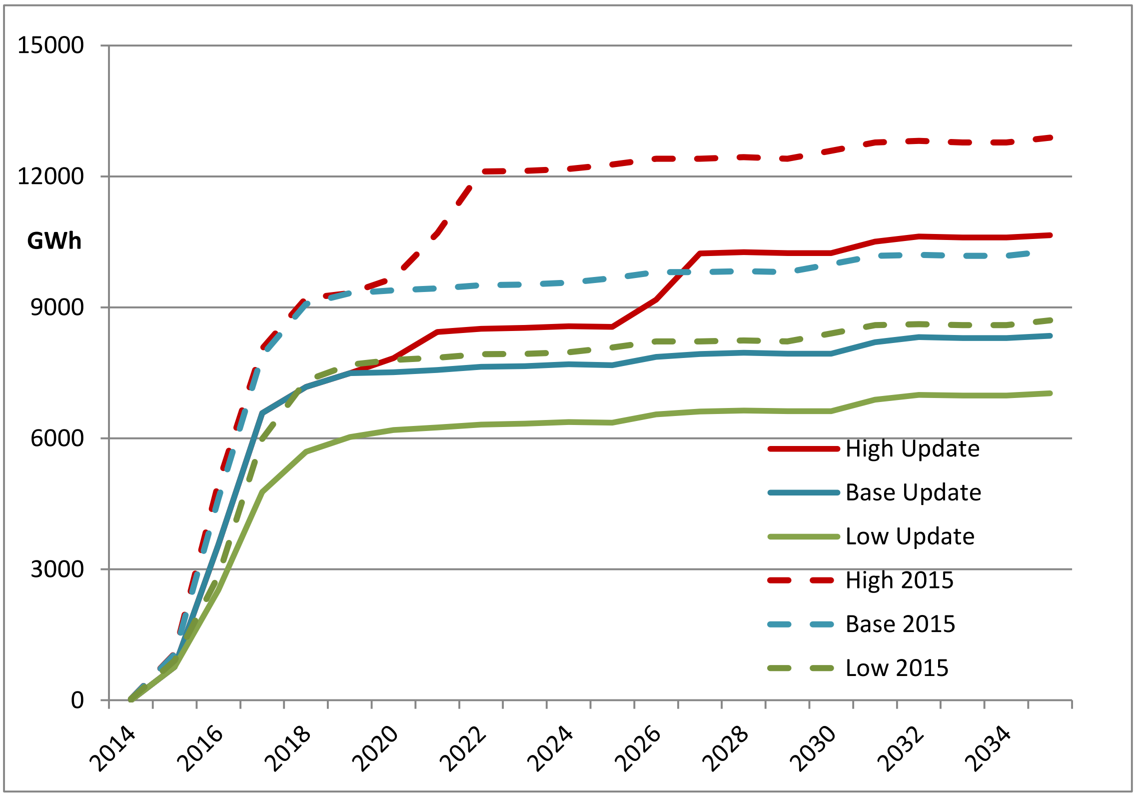


Figure E 3 Total grid electricity usage



Summary of changes to the projections

Changes to the projections in this update report compared to the initial report are summarised below. It is emphasized that the changes reflect more detailed LNG project information becoming available rather than actual changes to the projects.

- LNG exports – minor changes to timing of start-up, no changes to ultimate volumes in Base and Low Scenarios and a 3.4% increase in the High Scenario.
- Gas used in liquefaction – reduced from 8.0% to 7.6% in aggregate. A seasonal pattern of gas use in liquefaction is used in this update.
- Gas used in transmission compression (High Scenario only) - no changes
- Gas used in processing – increased due to the additional 1% gas usage at the wellhead assumed at QCLNG and APLNG electrically driven upstream plant
- Grid-supplied electricity used in processing – 20% reduction in electricity use in gas processing due to revised estimates of use per unit of gas produced. 18% reduction in winter MD and 22% reduction in summer MD.

1. Introduction

1.1 LNG exports from Gladstone

This section does not require updating.

1.2 The export projects

Since the initial report was prepared QCLNG's first LNG train was declared "commercial" (delivering LNG cargoes according to contract) in May and QCLNG's second train became operational in July. First LNG from the first trains of the two other export projects, GLNG and APLNG, has been re-scheduled to late in the September quarter and in the December quarter respectively. There have been no further announcements regarding development of the Arrow Energy's gas reserves.

1.3 Information cut-off date

The modelling documented in this report incorporates information available as at 26th September 2015. Since that date the following potentially material information has become known:

- GLNG exported its first LNG cargo on Friday 16th October

2. Scenarios

2.1 Determining factors

LGA has constructed three scenarios for LNG exports from eastern Australia based on near-term, mid-term and long-term considerations. These are:

- AEMO planning and forecasting scenarios
- LNG projects operating, under construction and planned
- Gas resource availability
- Global LNG demand and competition from other suppliers.

There have been no material developments in the first three factors. Oil and LNG spot prices, together with global LNG demand, remain weak and the outlook is for this to continue. Market analysts have questioned whether the Queensland LNG projects will meet their production targets but to date the project operators have maintained the view that their output will be cash flow positive and meet their targets, even though the financial returns have significantly reduced.

2.2 Scenario selection

The scenario definitions are the same as in the initial report. The Base Scenario is intended to reflect the sale of contracted volumes of LNG produced using the resources indicated by documents released by the project operators. The Low and High scenarios are intended to represent feasible alternative outcomes.

At AEMO's request the High scenario has been varied in two respects:

- Production at the 6 existing trains is assumed to be extended to 110% of contract volumes instead of to plant capacity. This results in a 3.4% expansion of total production at these trains in this scenario, from 25.3 Mtpa to 26.2 Mtpa. Production above nameplate capacity is common among LNG plants.

- Construction and operation of the 7th train is assumed to be delayed by a further 5 years, to 2026.

3. Methodology

3.1 Overview

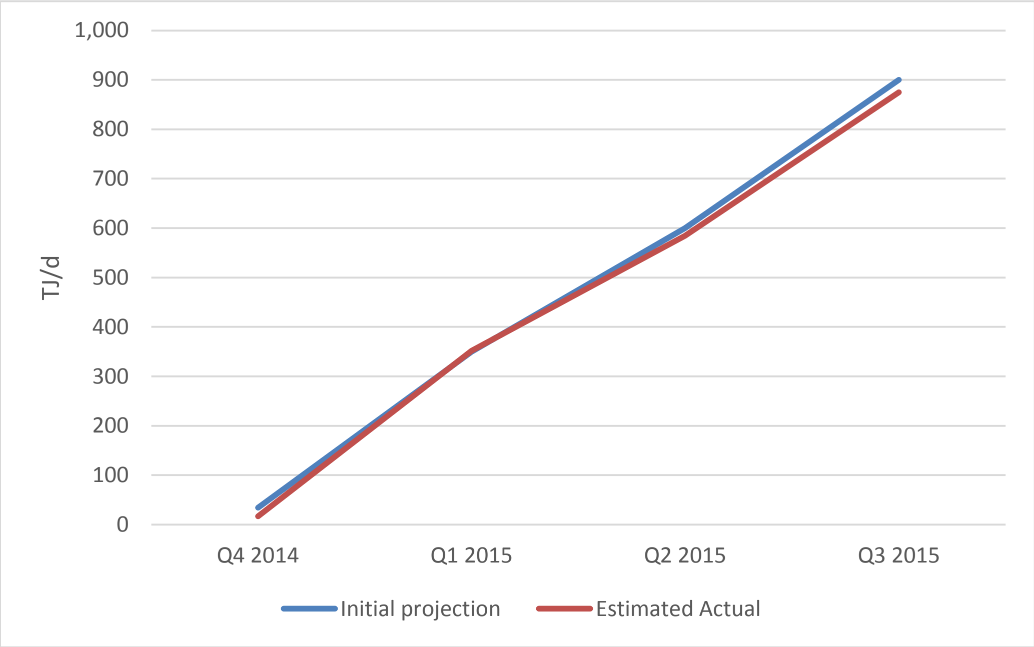
The methodology used to produce the updated projections is as described in the initial report.

3.1.1 Historical data

3.1.1.1 Exports

QCLNG shipped the first LNG from Gladstone in the Methane Rita Andrea on the 5th January 2015, having commenced liquefaction in late December 2014. According to Energy Quest[2], the departure of the Maran Gas Sparta on 27th July marked the 31st cargo and 2 MT of exports. Based on recent gas production rates LGA estimates that QCLNG is currently running at an annualised production rate of 7MT, equivalent to 87% of contracts and 82% of nameplate capacity. This level of production is consistent with the Base Scenario in the Initial Projections, which predicted 7.2 MT in financial 2015/16. Figure 3-1 compares the initial projection with estimated actuals derived from the above and reflects that QCLNG has met its LNG production targets to date.

Figure 3-1 Initial projection vs estimated actual gas used for LNG (TJ/d)



Source: LGA estimates

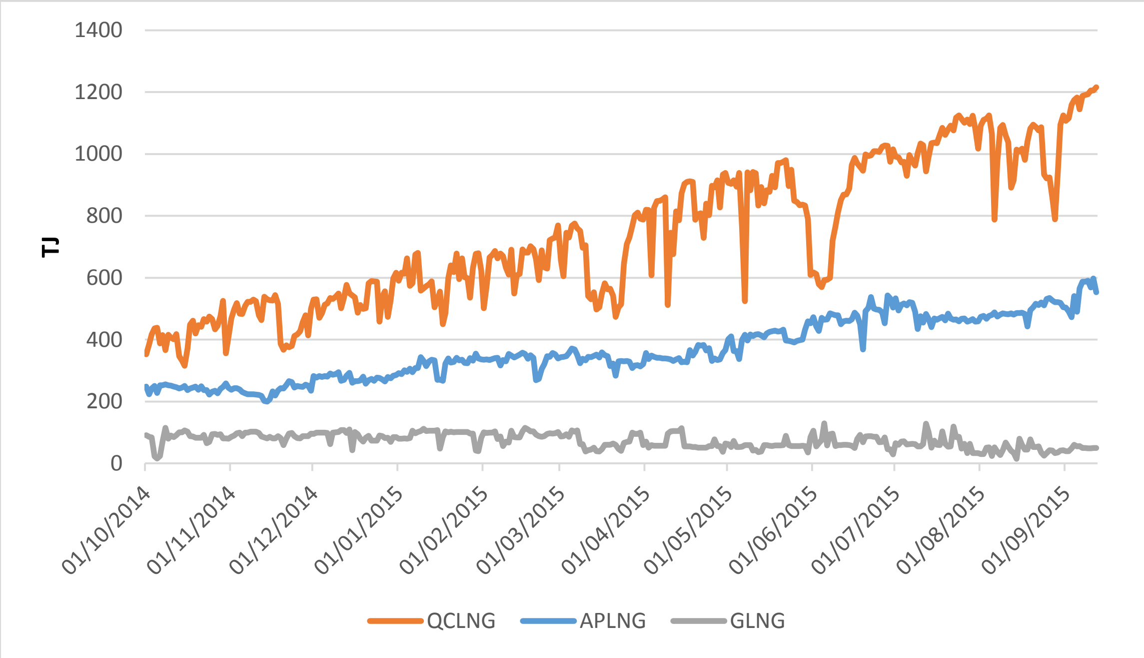
3.1.1.2 Gas production

Reported production of CSG by the three projects since October 2014 is shown in Figure 3-2.This clearly shows QCLNG production ramping up from 400 TJ/d to 1200 TJ/d consistent with steady growth of LNG production, with a number of major shutdowns. APLNG's production has also ramped up to 600 TJ/d prior to commencement of its first LNG train but the same is not true of GLNG. LGA understands that this is due to GLNG's Bulletin Board reports being restricted to gas delivered to Wallumbilla rather than the absence of any ramp gas production. In April 2015 Santos reported that it was injecting gas into the Roma storage at a rate of 100TJ/day[3].

[2] QCLNG reaches 2 million tonnes of Australian east coast LNG exports, Energy Quest, 28 July 20015

[3] Cooper and GLNG Investor Visit (20-23 April 2015)

Figure 3-2 Daily CSG production



Source: AEMO Gas Bulletin Board

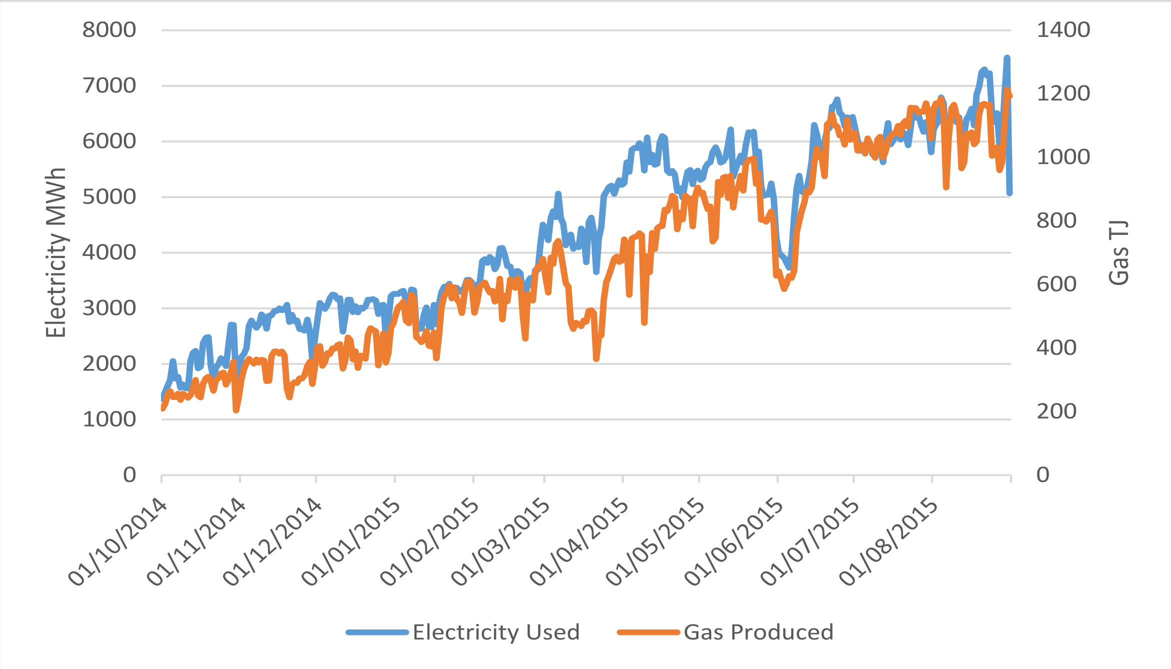
Unfortunately, precise estimates of gas used in LNG production cannot be derived from the QCLNG's CSG production figures, owing to the unknown quantities supplied to the domestic market and the unknown quantities of third party gas used by QCLNG for LNG production. Accurate estimates of gas used in LNG production could be derived from LNG transmission pipeline gas flows; LGA understands that these will be available after a second LNG project has started production.

Use of the production data to estimate ramp gas production is described in section 3.6.3 and combined use of the production data and information regarding electricity usage by the gas processing plants is discussed in section 3.6.4.

3.1.1.3 Electricity usage

Aggregate electricity usage by the LNG projects to date is presented in Figure 3-3 alongside gas produced at plants with electrically driven compressors. Electricity use has grown to 7000 MWh/day (an average of 290 MW). The chart also shows a clear correlation of electricity use with gas production, though with periods during which gas production is relatively lower. Use of this data to derive estimates of electricity usage per unit of gas produced is described in section 3.6.4.

Figure 3-3 Aggregate daily electricity usage vs aggregate electricity powered gas production



Source: AEMO and Gas Bulletin Board, LGA analysis

3.2 Gas exported

The assumed plateau export levels in each scenario are unchanged from the initial report.

Start-up and ramp timing assumptions are presented in Table 3-1.

- The Base Scenario is LGA's interpretation of most recent timing statements by projects:
  - QCLNG[4]: Train 1 (T1) started in December 2014 and reached commercial production in Quarter 2 (Q2) 2015; T2 started up July 2015 and is expected to reach full production by CY 2016
  - GLNG[5]: T1 start up end of Q3 CY 2015, ramp-up over 3-6 months; T2 ready by the end of H2 CY 2015; ramp up over 2-3 years
  - APLNG[6]: T1 start up Q4 CY 2015; sustained production Q2 2016; T2 six months later start up and sustained production
- High Scenario: For all projects acceleration of start-up of either train seems unlikely. Some acceleration of T2 ramp up is assumed. For the High Scenario "Plateau" means the contract level with the increase to 110% of contracts occurring in 2020.
- Low Scenario: First LNG and plateau are delayed relative to Base Scenario for all elements except QCLNG T1. This would be consistent with minor technical problems prior to or during start-up.

4 BG Group 2014 4th quarter & full year results presentation and transcript (3rd Feb 2015)

5 Cooper and GLNG Investor Visit (20-23 April 2015)

6 ORG Macquarie Conference Presentation May 5 2015

Table 3-1 Start-up and ramp-up timing

	QCLNG				GLNG				APLNG			
	T1		T2		T1		T2		T1		T2	
	Actual Start	Actual Plat	Actual Start	Plat	Start	Plat	Start	Plat	Start	Plat	Start	Plat
High	Q4 14	Q2 15	Q3 15	Q2 16	Q4 15	Q2 16	Q2 16	Q4 17	Q4 15	Q2 16	Q2 16	Q3 16
Base	Q4 14	Q2 15	Q3 15	Q3 16	Q4 15	Q2 16	Q2 16	Q3 18	Q4 15	Q2 16	Q2 16	Q4 16
Low	Q4 14	Q2 15	Q3 15	Q4 16	Q4 15	Q3 16	Q4 16	Q3 19	Q1 16	Q4 16	Q3 16	Q2 17

Notes: T1 = Train 1 first gas exported; T2 = Train 2 first gas exported; Plat = Plateau production reached for each train; Q1 = first quarter of the calendar year etc.

3.3 Energy used in LNG production (liquefaction)

3.3.1 Energy sources

There are no updates for this section.

3.3.2 Testing gas usage

The assumed figure of 10TJ/d is confirmed by Reference 1.

3.3.3 Liquefaction gas usage

Reference 1 states an LNG plant efficiency target of 92.6%, indicating slightly higher efficiency than the 92% efficiency figure used in the initial report. Since all three plants use the same technology, this figure is used for all plants in this update, resulting in a decline in the estimates of gas used in LNG production.

Reference 1 also notes that the efficiency has considerable seasonal variation, ranging from 90% in winter to 94.6% in summer. This has been incorporated in the projections, which are calculated on a quarterly basis, by using the summer efficiency in Q1, the winter efficiency in Q3 and the average efficiency in Q2 and Q4. This results in seasonal variations in gas and electricity usage and different maximum demands in summer and winter.

3.4 Energy used in gas transmission

LGA's assumptions regarding energy used in transmission are as in the initial report.

3.5 Energy used in gas storage

For the same reasons as in the initial report, energy used in underground gas storage is omitted from the energy usage estimates.

3.6 Energy used in gas supply

3.6.1 Gas supply

CSG resources required to support an 8 Mtpa project for 20 years, including gas used in production and ramp up/down gas, are estimated to be approximately 12,000 PJ[7]. The principal source of these resources for each project will be their equity reserves in Queensland CSG, for which updated values are presented in Table 3-2. Total reserves have grown by 2% compared to the values at 30th June 2014 used in the initial report. Most of this growth was reported by Arrow Energy.

GLNG and QCLNG also rely upon third party gas supplied under long term contracts. Updated estimates of gas volumes are reported in Table 3-3. Since the initial report was compiled GLNG has entered a new supply agreement with Senex Energy, as discussed below.

Table 3-2 LNG project equity and operated Queensland CSG reserves as at 31 December 2014 (PJ)

	Equity	Operated
QCLNG	10,469	12,262
GLNG	5,865	6,747
APLNG	14,217	11,808
Arrow Energy	8,851	10,447
Others	3,458	1,598
Total	42,860	42,860

Source: Queensland Department of Natural Resources and Mines

Table 3-3 LNG project contracts with third party suppliers

Seller	Operator	Buyer	Source	Delivery Point	Term (years)	Total Volume (PJ)	Annual Volume (PJ)
APLNG	QCLNG	QCLNG	Surat CSG	Field	20	640	95 falling to 25 after 2016
Santos	Santos	GLNG	Cooper primarily	Wallumbilla?	15	750	50
AGL	QCLNG	QCLNG	Surat CSG	Field	3	75	25
Origin	Unknown	GLNG	OE Portfolio	Wallumbilla	10	365	36.5
Origin	Unknown	QCLNG	OE Portfolio	Wallumbilla	2	30	15
Origin	Unknown	GLNG	OE Portfolio	Wallumbilla	5	100 Firm 94 Sellers option	20-39
Stanwell	Unknown	GLNG?	Wallumbilla?	Wallumbilla?	1.75	53	30

[7] Approximately 9,500 PJ for 20 years production plus 2,500 PJ for ramp up/down. Ramp down is the minimum reserves required to support production of 475 PJ in the 20th year.

Seller	Operator	Buyer	Source	Delivery Point	Term (years)	Total Volume (PJ)	Annual Volume (PJ)
AGL	QCLNG?	GLNG	Surat CSG	Wallumbilla?	7	32	4.6
Meridian JV	Westside	GLNG	Bowen CSG	GLNG Pipeline	20	445	24

Sources: Company media statements. A question mark indicates that the relevant information has not been published and that the value in the table is the best estimate.

Complementary to the first contract, it has been assumed that APLNG will take 70 PJ of its equity share in the QCLNG operated fields, at the time it reaches plateau LNG production levels in 2016. There are also arrangements between GLNG and APLNG for GLNG to take approximately 12 PJ pa of equity gas at Combabula and APLNG to take 35 PJ pa of its equity gas at Fairview.

On 24th September 2015, Senex Energy announced a gas sales agreement with GLNG to be underpinned by development of the Western Surat Gas Project, located to the north of GLNG's Roma gas field. The agreement envisages 50 TJ/d gas sales over a 20 year period. Some gas sales may commence ahead of FID, which is scheduled for 2017, but full sales would be reached sometime after 2017. The project may share GLNG's Roma pipeline and processing facilities and if so could be regarded as an expansion of the Roma project for the purposes of these projections.

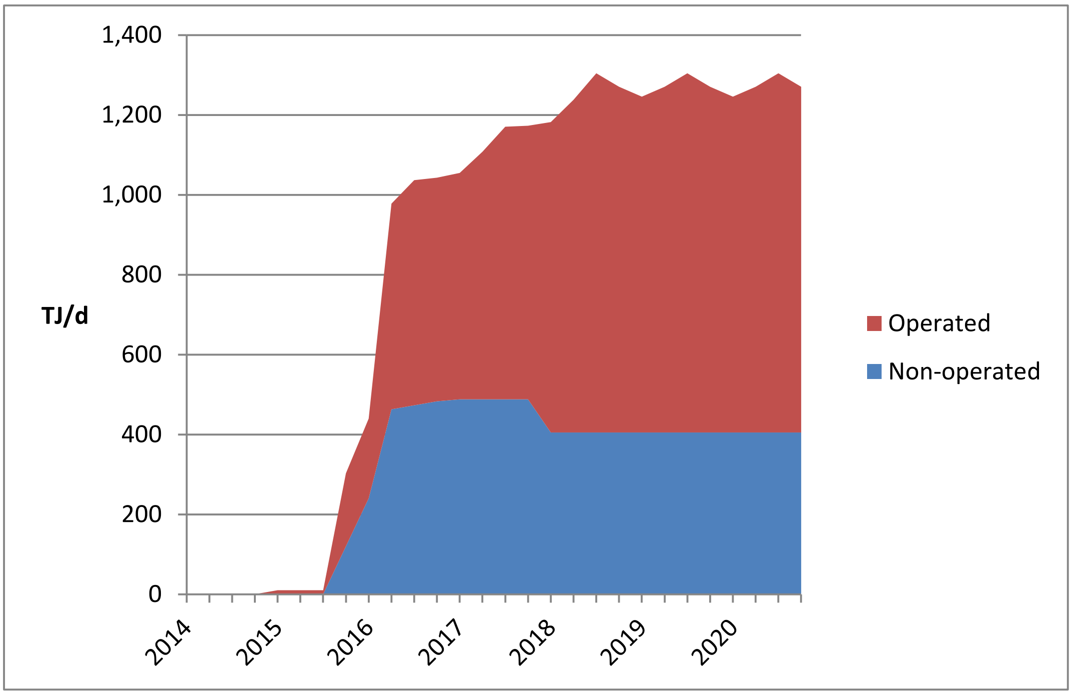
3.6.2 Supply model

The supply model has not been changed for this update but is reproduced in this section because of the changes to the outcomes reported in this section of the initial report.

For each LNG project, the contracts are separated into "operated" (contracts 1 and 3 above) and "non-operated" (all other contracts). The non-operated contracts are assumed to be used to their maximum subject to the LNG plant's gas requirements, as it is reasonable to assume the contracts all have high take-or-pay provisions. The operated gas requirement is then the LNG plant requirement, less the relevant non-operated contract volume, plus supply obligations to other projects. It is also assumed that contracts are not recontracted on termination but are replaced by additional equity gas.

Figure 3-4 illustrates the application of this approach to GLNG in the Base Scenario. The seasonal variations in liquefaction use (refer to section 3.6.4) are assumed to be taken up by the gas fields operated by GLNG.

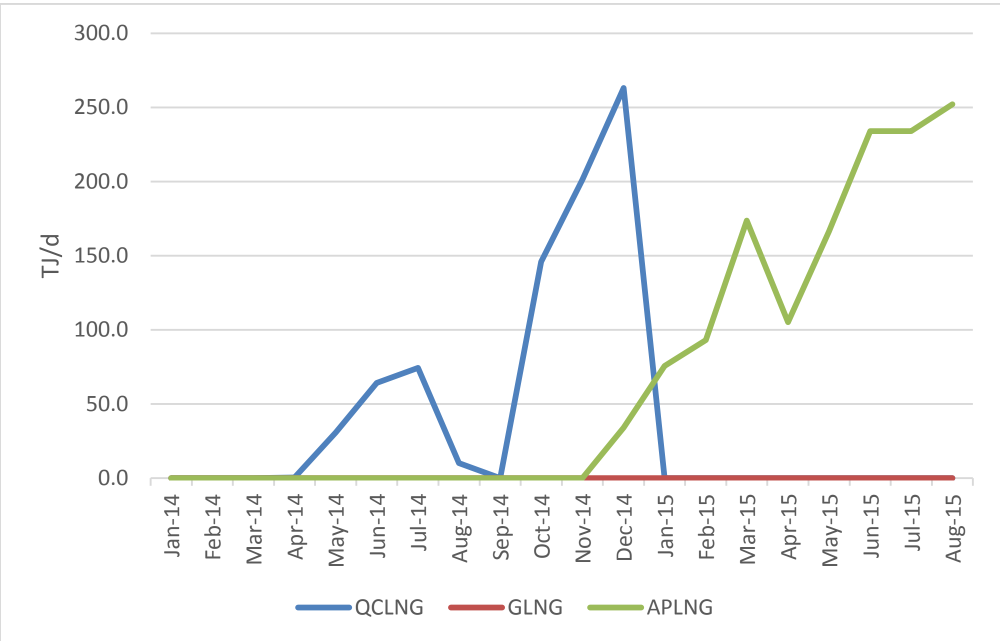
Figure 3-4 GLNG Base Scenario gas allocation to operated and non-operated – average daily supply



3.6.3 Ramp gas

As GLNG and APLNG are scheduled to start LNG production in the coming quarter, ramp gas production will most likely cease during the quarter. Estimates of ramp gas produced to date are shown in Figure 3-5. The QCLNG and APLNG estimates are broadly similar, rising to levels of approximately 250 TJ/day over 9 month periods. As noted in section 3.1.1.1, GLNG reports only production that is directed to the domestic market at Wallumbilla. Figure 3-5 indicates that GLNG did not make any ramp gas available to the domestic market.

Figure 3-5 Ramp gas produced to date



3.6.4 Gas field and processing plant energy usage

3.6.4.1 Operated gas

The primary energy requirements are for field and plant gas compression, with lower requirements for auxiliaries including water pumping and desalination. Following discussions with LNG project representatives in conjunction with AEMO, LGA has a clearer understanding of how these functions will be powered:

- All three projects are using electric drive compressors at their gas processing plants for most of their new developments. APLNG plans to use gas engines at some of its smaller, as yet to be constructed, processing plants (Reference 1).
- For new wells GLNG is using electric compression at the well head whereas QCLNG and APLNG are using gas engines.
- All electricity for the above will ultimately be sourced from the Queensland electricity grid. Use of temporary gas turbines is described in the initial report.
- All existing gas powered plant will remain gas powered.

The proportions of electricity and gas powered compression at processing plants in the initial phase of LNG production (circa 2018) has been estimated assuming that domestic loads are met from existing gas powered plants, because these are already connected to domestic pipelines (Table 3-4). For QCLNG and GLNG, over time, as the initial well productivity declines and new wells and processing plants are constructed, which will be mainly electricity driven, the electricity powered proportion will increase. For APLNG however, because some new plants will be gas driven, the electricity powered proportion may decline.

Table 3-4 Initial proportions of gas and electricity powered compression at processing plants

	QCLNG	GLNG	APLNG
Gas Powered	12%	11%	2%
Electricity Powered	88%	89%	98%

Source: LGA estimates, assuming domestic markets are supplied from gas powered plant.

Aggregate energy usage for compression and auxiliaries (gas and electric driven) has been estimated using a combination of:

- For gas driven plant, historical CSG plant usage figures published by the Queensland Department of Natural Resources and Mines;
- For electric plant, correlations between CSG plant usage and electricity consumption figures provided to LGA by AEMO.

For gas-driven plant the values in Sources: AEMO, Gas Bulletin Board

Table 3-5 have been re-estimated using the most recent two years data from January 2013 to December 2014. The values expressed as a % of net gas produced have changed by just 0.1% from those in the initial report.

For energy usage from electrically driven plant AEMO has provided LGA with updated actual electricity usage data for the period October 2014 to August 2015 from all QCLNG and APLNG operating gas fields with grid powered compression. Electricity usage per unit of gas production in these fields (in aggregate) has trended downwards since March 2015 as gas production has risen (Figure 3-6). Analysis of daily electricity usage plotted against daily gas production (Sources: AEMO, Gas Bulletin Board

Figure 3-7) suggests that the current value of 6.2 MWh/TJ is a reasonable estimate of the lower bound of usage, towards which it is expected that usage will converge, and can therefore be used to project future electricity usage with more confidence than the earlier estimates used in the initial report. This figure converts to 2.23% of energy produced and this aggregate value has been applied to each project owing to its greater reliability compared to individual project or plant estimates.

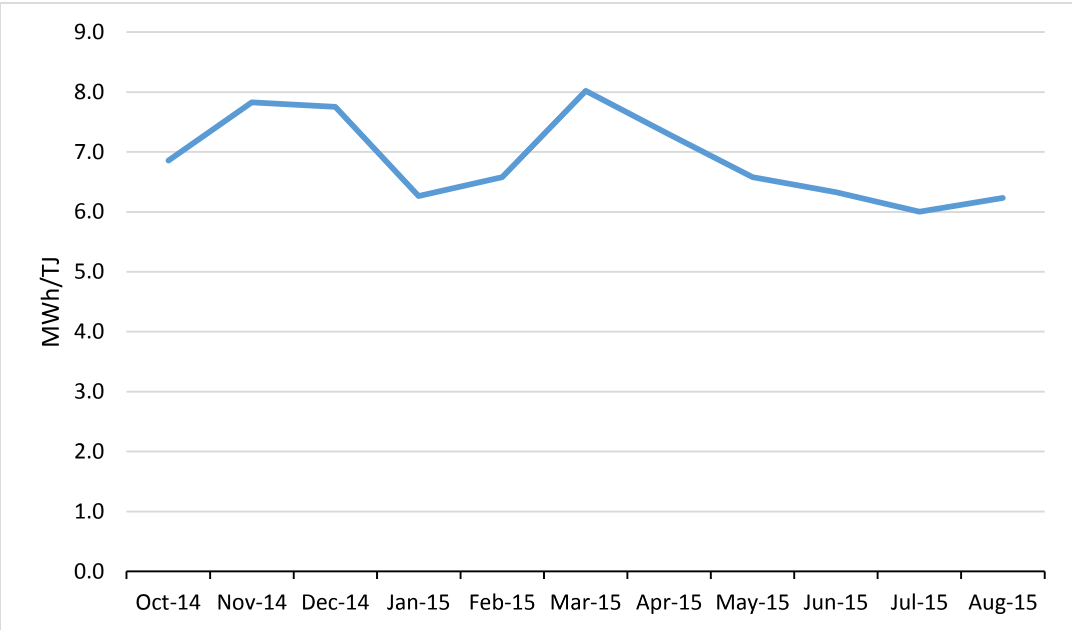
The above electricity usage covers only the processing plant compression and well head energy is provided by gas for QCLNG and APLNG. Reference 1 states that this additional gas use is equivalent to 1% of gas produced and this figure is used in the projections.

For GLNG, for which there is currently no electricity usage data, it is reasonable to expect that processing plant electricity usage will be the same as for the other projects, and that well head usage will be the electricity equivalent of the above 1% for gas driven well heads i.e. 0.28% of energy produced. This makes GLNG's total electricity usage 2.51% of energy produced, which is reflected in Sources: AEMO, Gas Bulletin Board

Table 3-5.

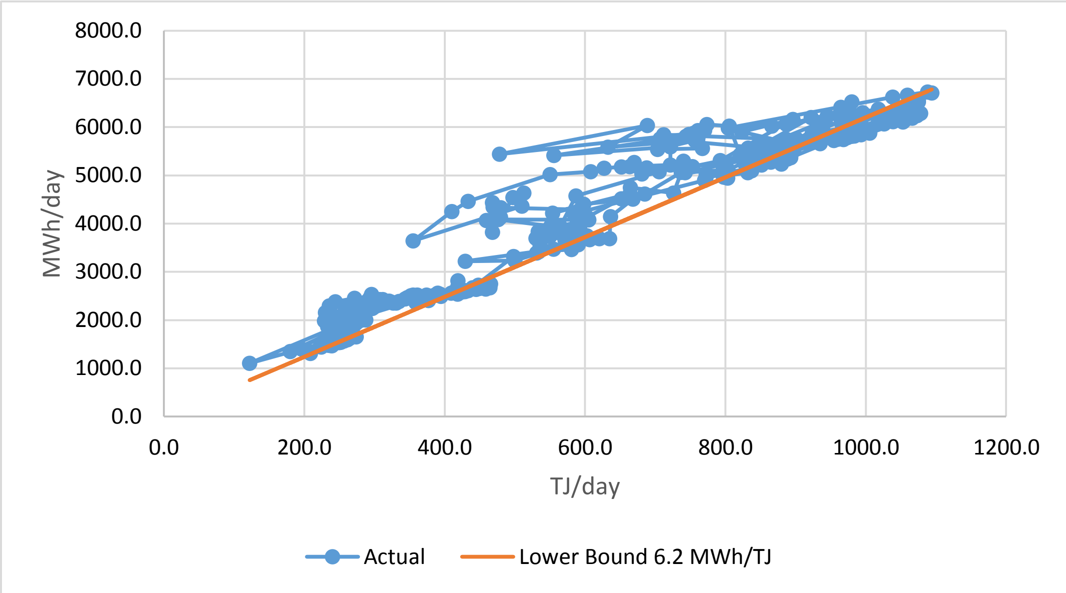
The electricity usage estimates represent significant reductions compared to estimates used in the initial report, which were based on data to February 2015.

Figure 3-6 Electricity usage per unit of gas production, aggregate of fields in production (MWh/TJ)



Sources: AEMO, Gas Bulletin Board

Figure 3-7 Aggregate daily electricity usage vs gas production



Sources: AEMO, Gas Bulletin Board

Table 3-5 Energy used in gas production (% of net gas energy produced)

		QCLNG	GLNG	APLNG
Gas driven plant	Gas	5.1%	6.4%	6.4%
Electricity driven plant	Electricity	2.23%	2.51%	2.23%
Electricity driven plant	Gas	1%	0%	1%

Sources: Queensland Department of Natural Resources and Mines; AEMO; Reference 1

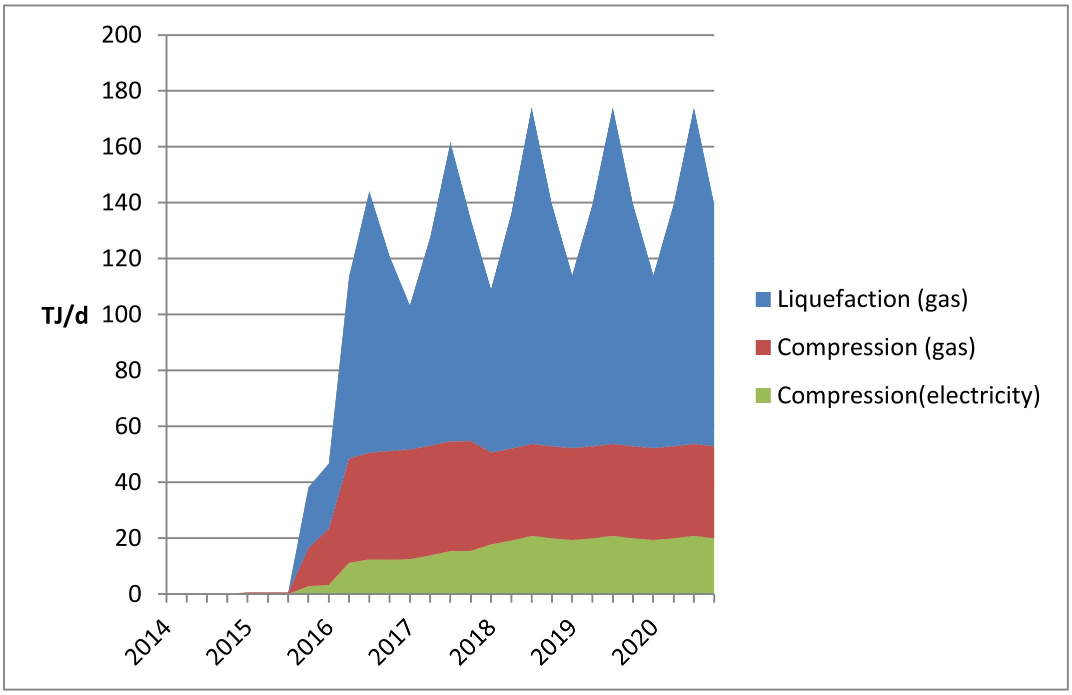
3.6.4.2 Non-operated gas

It has been assumed that all non-operated gas is non-grid connected and gas driven, with gas requirements set at 6.4% of net production, as for GLNG and APLNG above. This has not changed since the initial report.

3.6.5 Total energy usage

The total Base Scenario energy usage projection for GLNG is shown in Figure 3-8. The total usage falls slightly at the end of 2019 owing to a switch from gas to electrically driven compression, reflecting the lower energy requirement of electric compression, though this is largely concealed by the seasonality of liquefaction use.

Figure 3-8 Projected GLNG Base Scenario total energy usage



3.7 Estimates of peak gas and electricity demand

The methodology used to estimate peak gas and electricity demand is as described in the initial report. The seasonality of liquefaction use introduces strong seasonality of gas peaks and a smaller seasonality of electricity peak use.

3.8 Sensitivity of gas and electricity demand to gas and electricity prices

This section has not been updated for this report.

3.9 Potential for demand-side participation by the LNG plants in response to high electricity prices or high electricity demand

This section has not been updated for this report.

3.10 Confidence in the base scenario projections

This section has not been updated for this report.

3.11 Calculating monthly estimates

This section has not been updated for this report.

4. Projections

4.1 Annual projections

Updated total LNG export projections are presented in Figure 4-1, together with the equivalent projections from the initial 2015 report (dashed lines). The Base and Low scenarios are unchanged in the long run while the High scenario is 3.4% higher as production at the six existing trains is now set at 110% of the Base scenario instead of plant capacity. Export levels range from 20 Mtpa in the Low scenario to over 30 Mtpa in the High scenario. However each scenario takes slightly longer to ramp up owing to later start up at GLNG and APNG than assumed in the initial report and the assumed delay to the 7th train.

Figure 4-1 Total LNG export projections

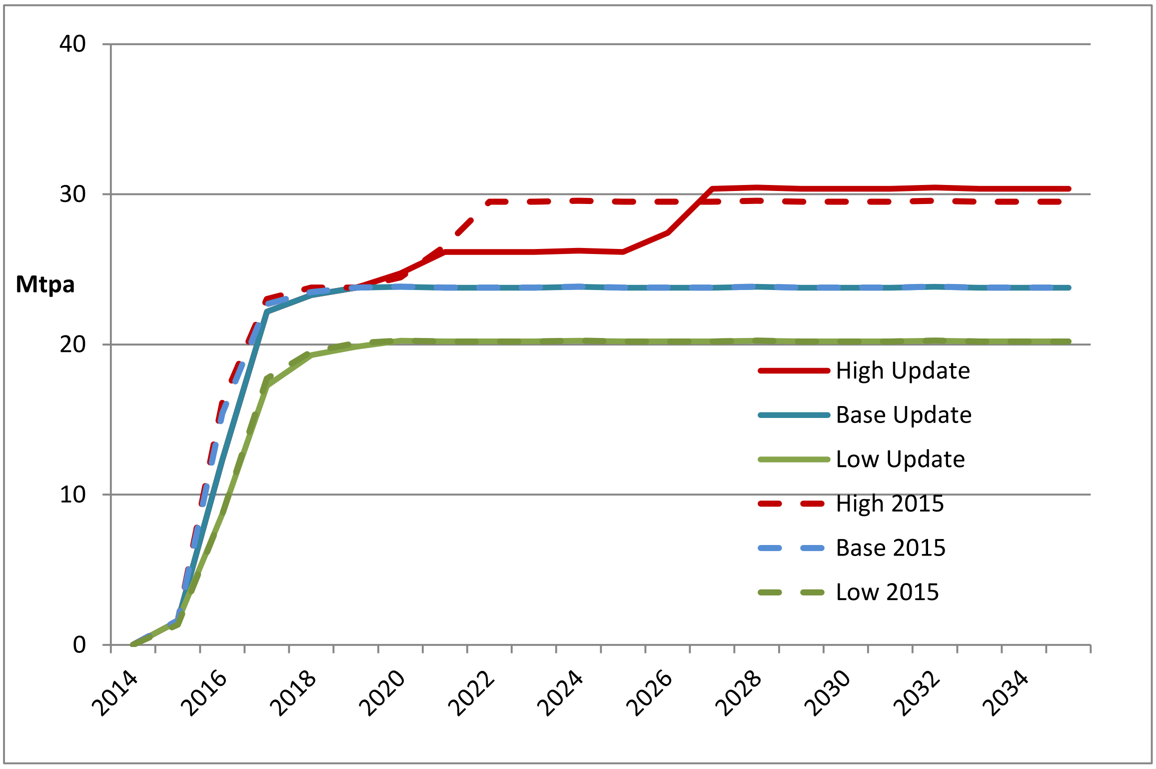


Figure 4-2 and Figure 4-3 show the total gas usage and total grid electricity usage respectively. The energy usage figures include estimates of energy usage in third party gas production.

For gas usage the Base and Low scenario updated projections are approximately 7% higher than the initial 2015 projections due to the additional gas usage assumed at QCLNG and APLNG electrically driven upstream plant (refer to section 3.6.4), slightly offset by lower usage in liquefaction. The High scenario is 10% higher after 2026 owing to the additional 3.4% of LNG production. In energy terms the increases in gas usage range from 7 PJ per year in the Low Scenario to 15 PJ per year in the High Scenario.

The updated electricity usage projections are each approximately 20% lower than the equivalent initial 2015 projections, mainly due to the revised estimates of the electricity requirements for gas compression (refer to section 3.6.4). In energy terms the reductions in electricity usage range from 1,600 GWh per year in the Low Scenario to 2,200 GWh per year in the High Scenario. The potential for material revisions to these estimates was foreshadowed in the initial report.

Figure 4-2 Total gas used in liquefaction and production

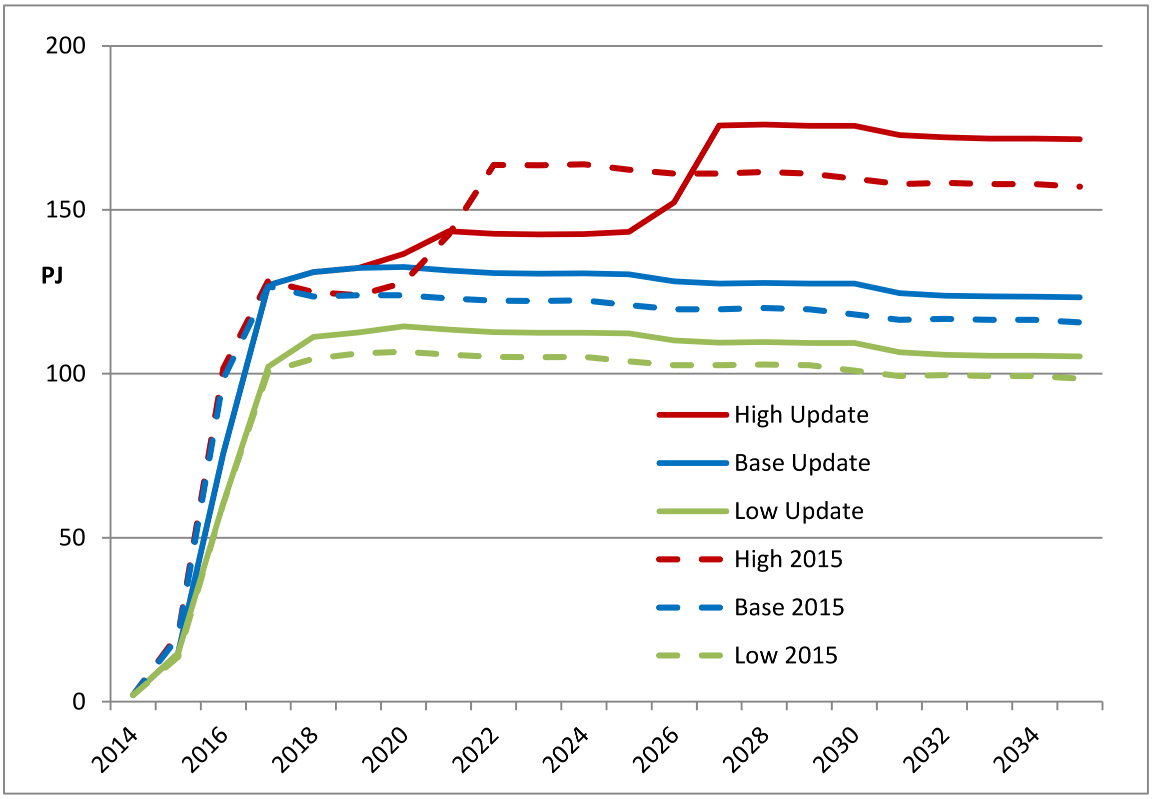


Figure 4-3 Total grid electricity usage

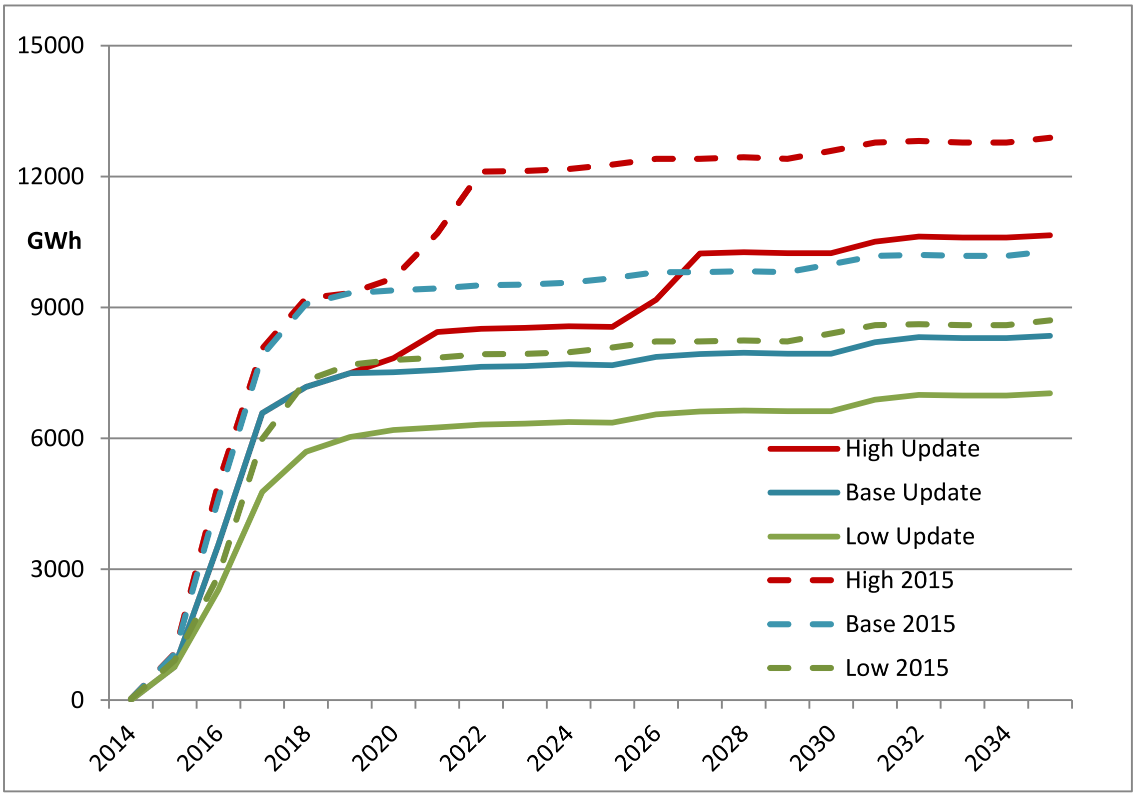


Figure 4-4 to Figure 4-6 show each projects' contribution to the Base Scenario projections, for LNG exports, gas usage and grid electricity usage respectively. The upstream components of energy usage figures are based on the upstream gas produced by each project, which is not directly related to its LNG exports owing to production of equity gas for other projects and use of third party gas. The GLNG project utilises proportionally more gas and less grid electricity than the other two, owing to its greater reliance on third party gas supply. GLNG's grid electricity usage also increases slowly in the longer term, because it is assumed that as third party contracts end, they are replaced by equity gas which is grid electricity powered.

Figure 4-4 LNG export projections, Base Scenario

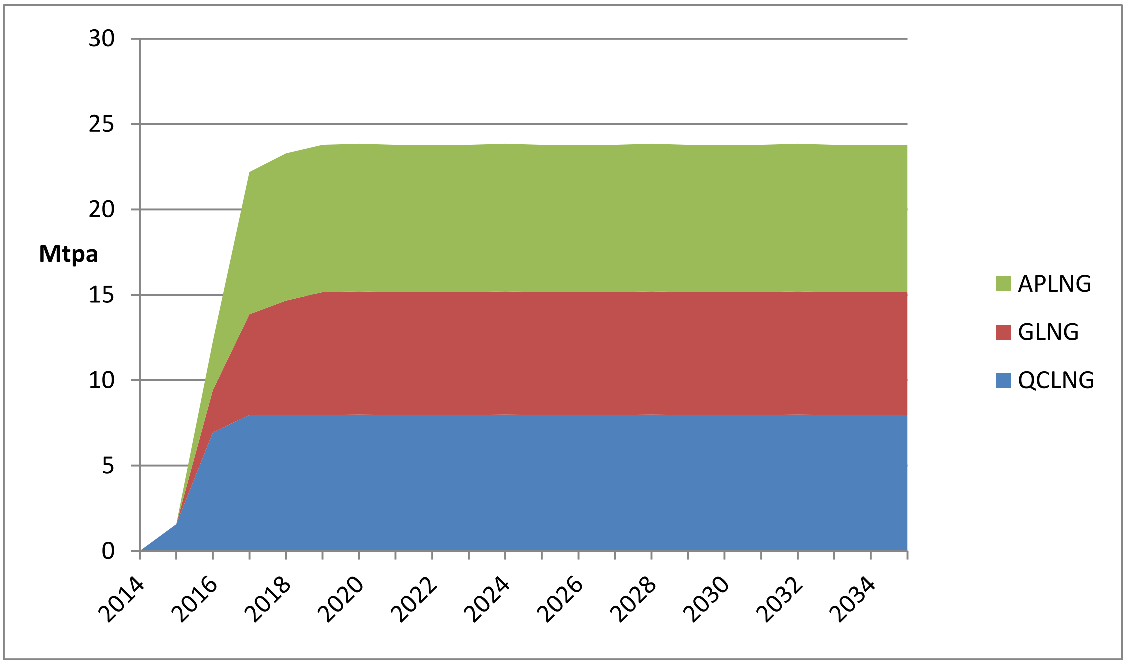


Figure 4-5 Gas used in liquefaction and production, Base Scenario

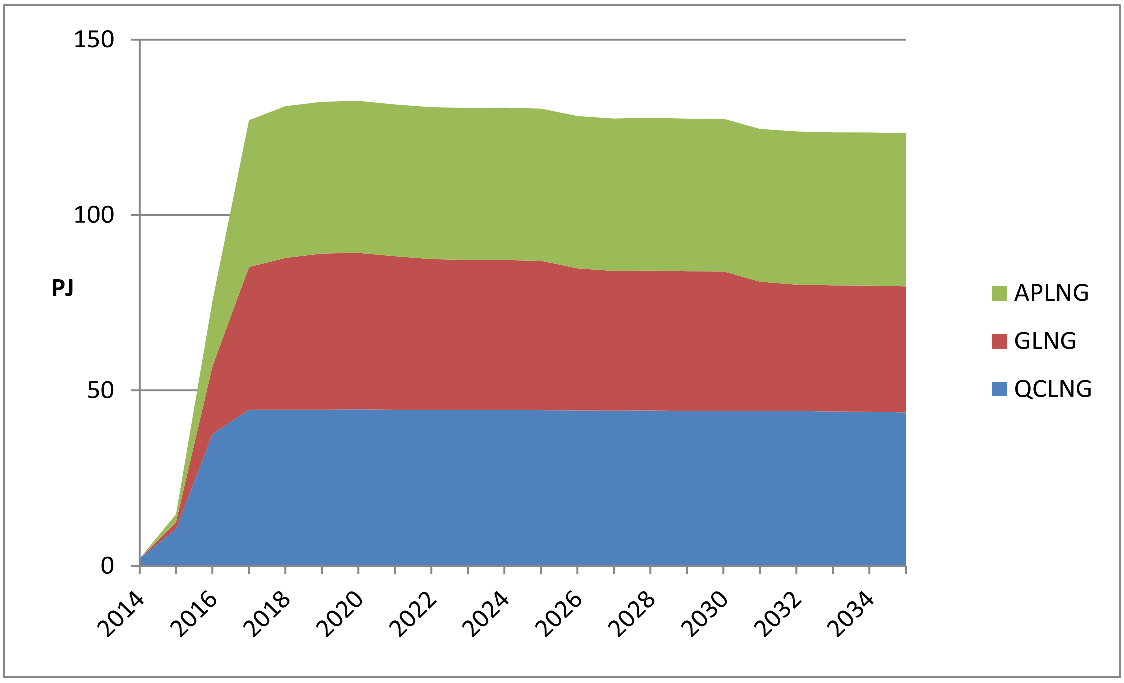
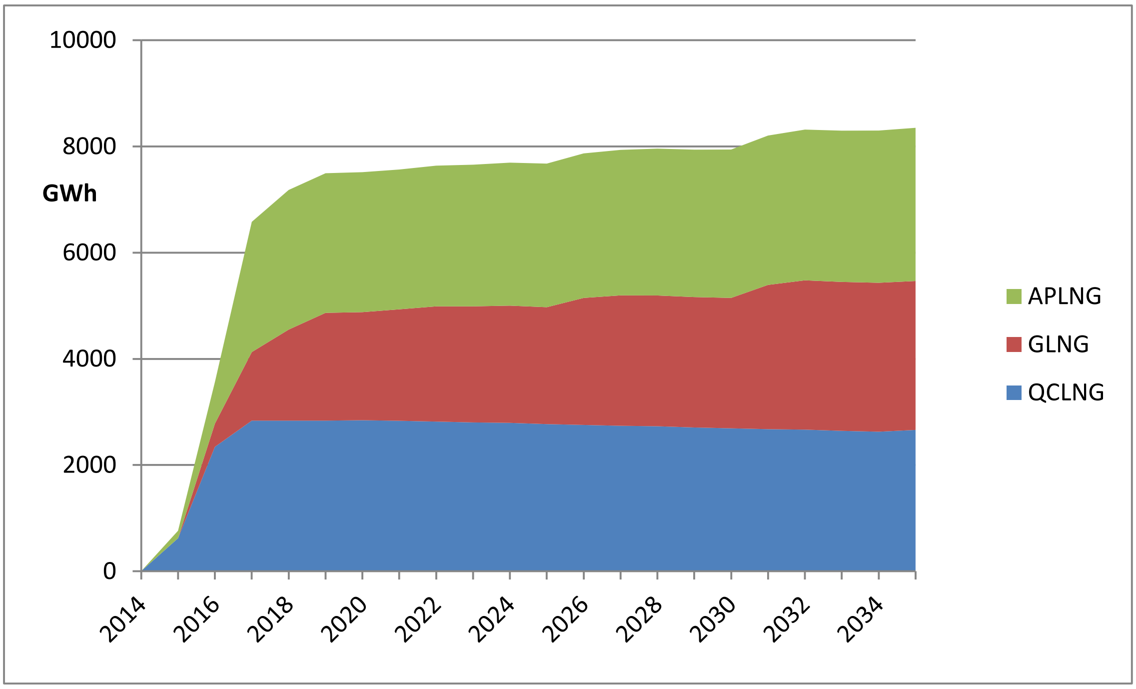


Figure 4-6 Grid electricity usage, Base Scenario



4.2 Peak demand projections

Figure 4-7 to Figure 4-9 show the peak winter gas and peak winter and summer grid electricity demand projections respectively. Winter/summer differentiation arises because of the assumed seasonality of gas use in liquefaction, which was not present in the initial 2015 projections.

Updated long-term peak gas demand projections range from 3,600 TJ/d in the Low Scenario to 5,450 TJ/d in the High Scenario. They are slightly higher than in the initial projections due to the assumed seasonality of gas use in liquefaction and the additional 3.5% of exports in the High Scenario.. The peak gas demands change only imperceptibly after the plateau export levels are reached.

In contrast, updated peak grid electricity demand projections are substantially lower than the initial 2015 projections due to the revised estimates of the electricity requirements for gas compression. Updated winter peaks are approximately 18% lower and updated summer peaks are 22% lower. The 4% difference between winter and summer is due to the assumed seasonality of gas use in liquefaction.

Base case winter MD is projected to be 981 MW in 2020, rising to 1,083 MW by 2035 owing to the assumed increase in the proportion of electrically compressed plant over time. Base case summer MD is projected to be 925 MW in 2020, rising to 1,040 MW by 2035.

Figure 4-7 Peak winter gas demand

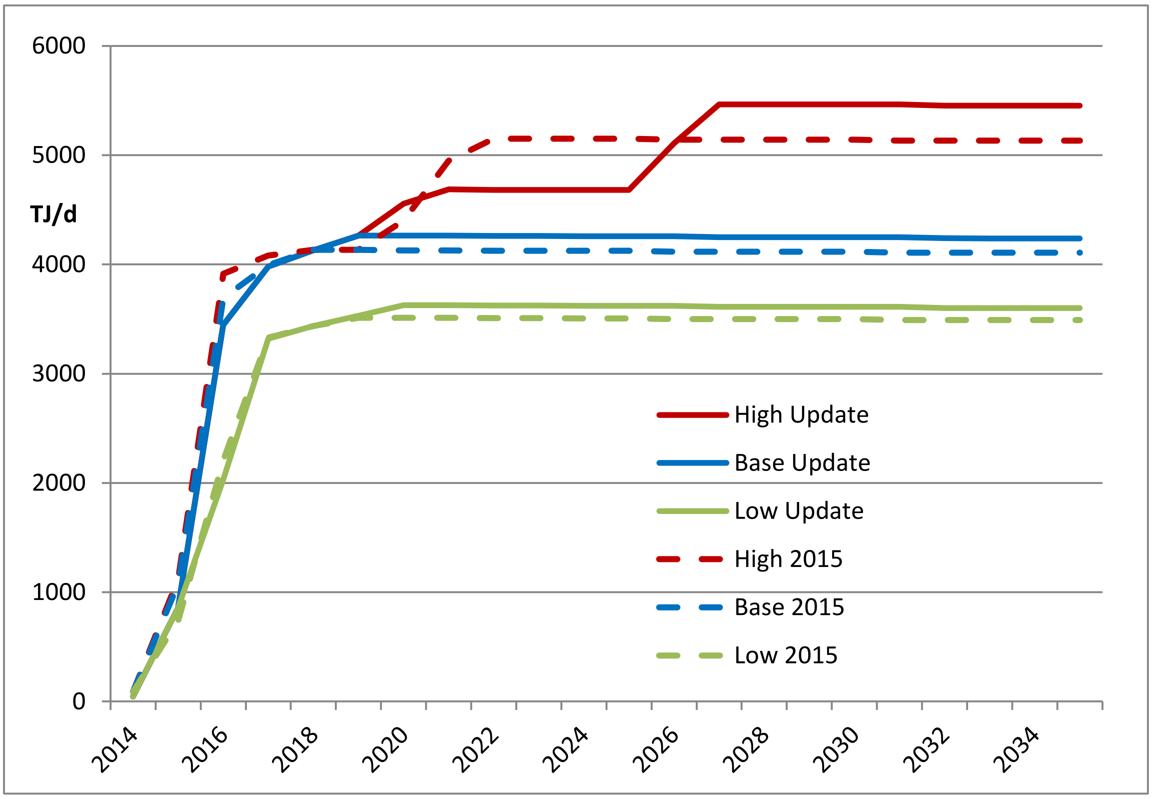


Figure 4-8 Peak winter grid electricity demand

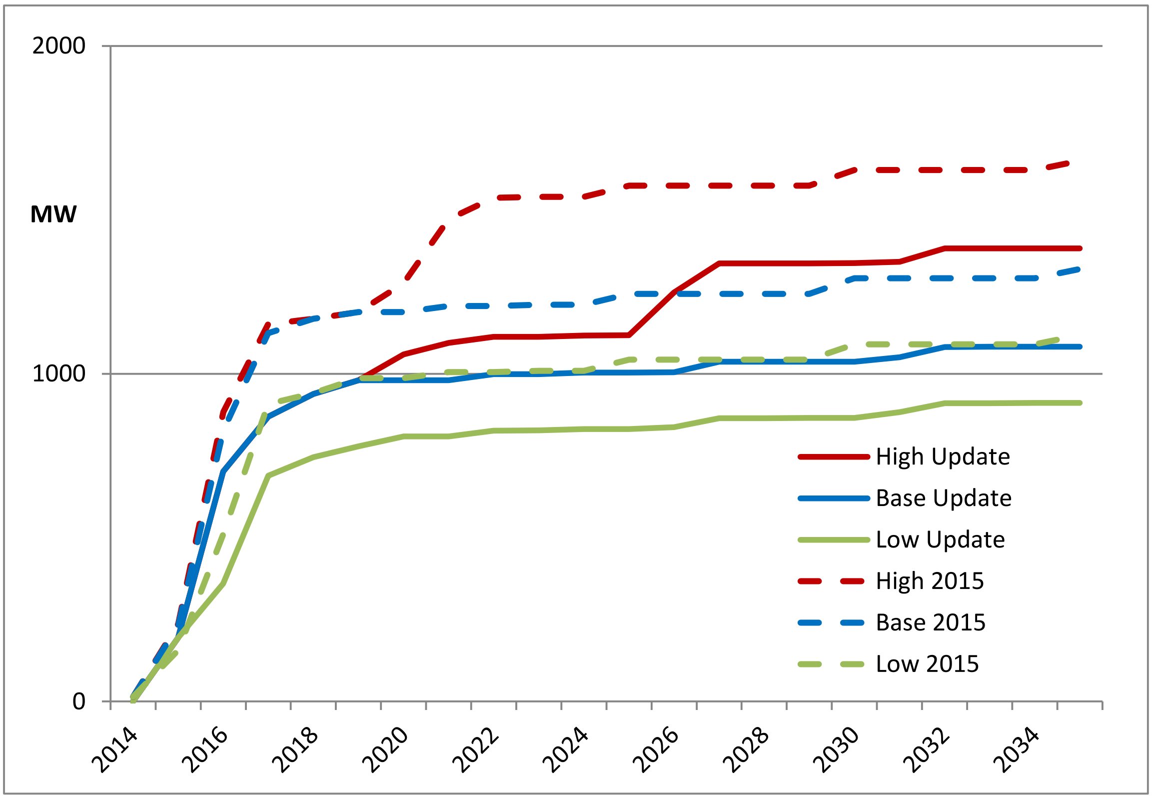
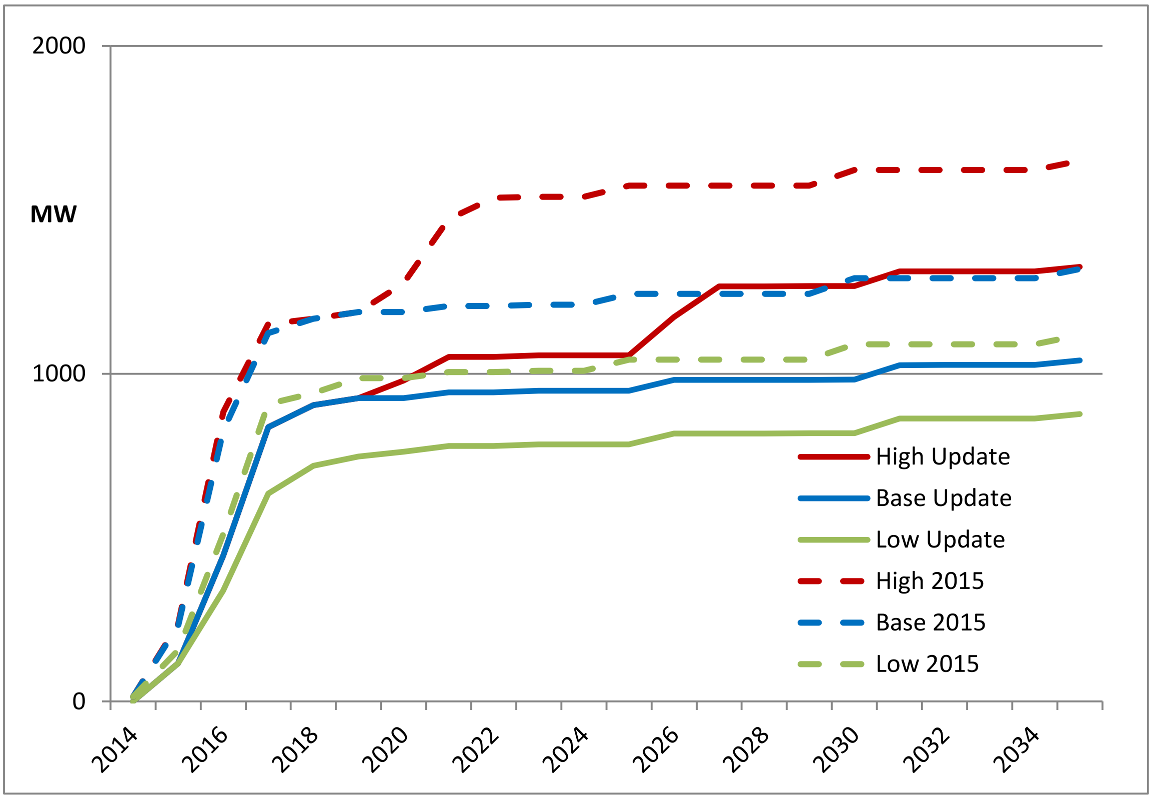


Figure 4-9 Peak summer grid electricity demand



4.3 Monthly projections

Monthly projections of LNG exports, gas usage and grid electricity usage to 2018 are presented in Figure 4-10 to Figure 4-12. High scenarios are not presented because they are the same as Base scenarios over this time period.

As with the annual projections, the updated LNG export projections are the same as the initial projections apart from later ramp up. Peaks and troughs in exports are mostly the result of differences in the numbers of days per month.

For gas usage, the monthly charts reflect the seasonality of liquefaction usage introduced in the updated projections (most gas is used in liquefaction).

For electricity the seasonality is barely apparent because electricity use is mostly upstream. The differences between the updated projections and the initial 2015 projections are largely due to the revised estimates of the electricity requirements for gas compression.

Figure 4-10 Total LNG export projections

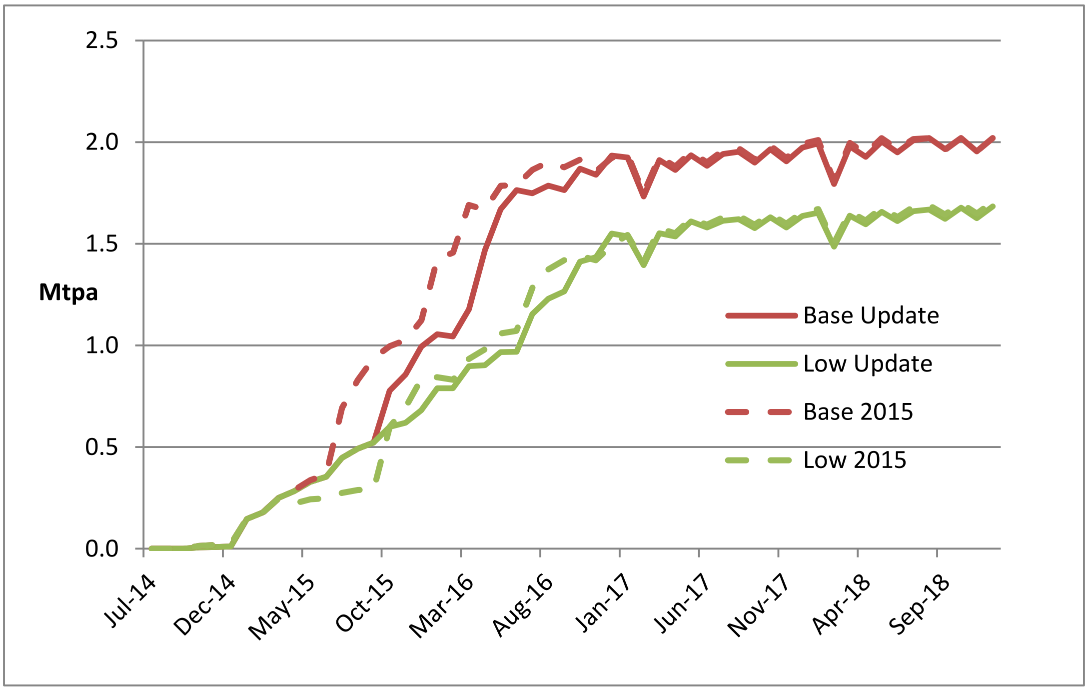


Figure 4-11 Total gas used in liquefaction and production

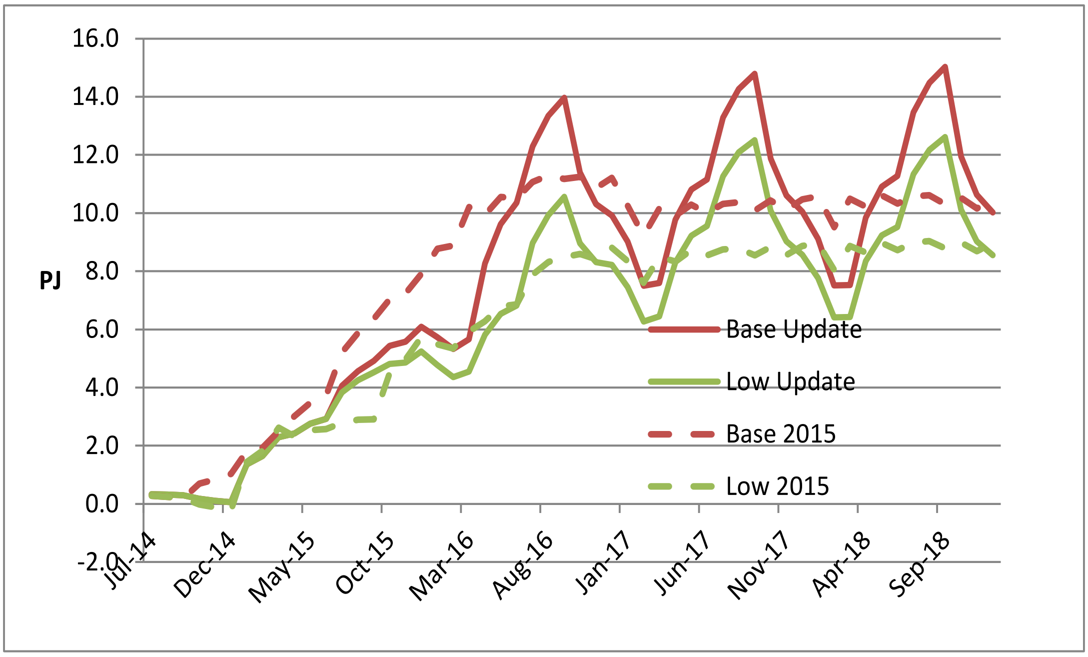
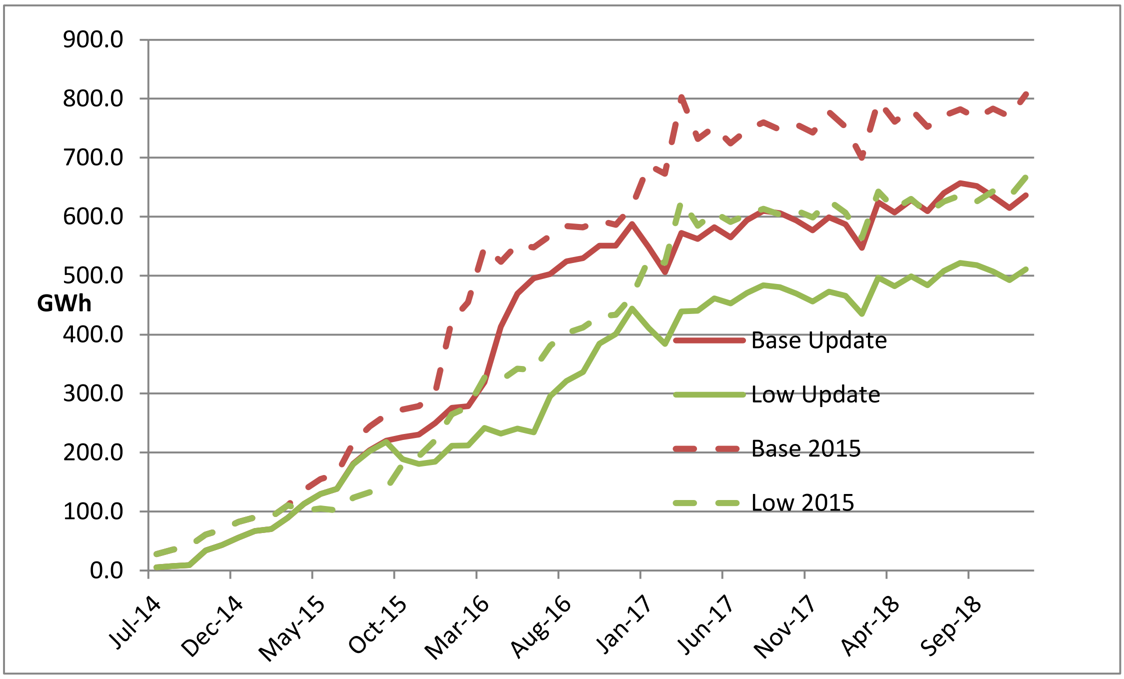


Figure 4-12 Total grid electricity usage



Appendix A. Abbreviations

AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
BBL	Barrel (of oil)
CSG	Coal seam gas (natural gas released from coal seams after drilling)
FID	Final investment decision
GJ, TJ, PJ	Giga-, Tera-, Petajoule (10^9, 10^{12}, 10^{15} joules)
GLNG	Gladstone LNG
JCC	Japan Customs Cleared crude price
LGA	Lewis Grey Advisory
LNG	Liquefied natural gas (gas cooled to -161C)
MMBTU	Millions of British Thermal Units
MTPA	Million tonnes per annum (of LNG)
MW	Megawatt
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NGFR	National Gas Forecast Report
ORG	Origin Energy
Q1, Q2, Q3, Q4	First, second, third and fourth quarters of calendar years
QCLNG	Queensland Curtis LNG
SRMC	Short run marginal cost
T1, T2	First and second LNG trains