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The feasibility of cost-effective gas through network interconnectivity: Possibility or pipe dream?

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ABSTRACT

Australia's east coast gas market has faced transformational shifts in demand with the commencement of three Liquefied Natural Gas facilities in Queensland. Faced with risks of high domestic prices and potential gas shortages, political intervention has been considered as a possible solution. This paper investigates the impact of network interconnectivity on domestic gas prices by employing a long-term planning model underpinned by mathematical optimisation. At optimal system cost, improved network interconnectivity can provide material and sustained price reductions for the gas market with potential flow-on reductions to the electricity market. Increased connectivity is shown to deliver reductions of over $2/GJ in average gas prices across the eastern seaboard, with a subsequent reduction in electricity prices across all mainland National Electricity Market (NEM) regions. The results also highlight the need to unlock new supply as new transmission projects, though having the potential to reduce gas prices through market connectivity, rely on adequate supply to meet long term demand, and sustain market balance.

1. Introduction

The eastern Australian gas market has recently experienced its largest structural revolution since the privatisation of gas assets in the 1990s. The development of three Liquefied Natural Gas (LNG) projects in Queensland has transformed the market dynamics of the previously stable eastern Australian markets, which were dominated by low-priced, bilateral long-term gas contracts [1]. Given the scale of gas demand from the LNG facilities, concerns have been raised around the adequacy of existing supply with the possibility of unserved load events or customer curtailments [2,3]. The Australian Energy Market Operator (AEMO) has projected gas shortfalls of 54 and 48 Petajoules (PJ) over 2018 and 2019 respectively, which is around 8.0% of annual domestic demand [4]. The tight balance between domestic demand and supply has also driven domestic prices from historical levels of $3[1] per Gigajoule (/GJ) to $9/GJ. Domestic prices are now linked to the north-Asian export market price on an equivalent ex-field netback basis [5], which in turn links the final price of gas paid by the end user to international gas price dynamics. Reviews by the ACCC in 2016 and 2017 show retail contract offers as high as $20/GJ [1] prompting broader market concerns over energy affordability for consumers and industry.

The impact of this supply demand imbalance is broader than the gas market on its own. Given the use of gas as a fuel source for power generation, shifts in gas supply and prices could also affect the electricity market. Scarcity in gas supply impacts the ability of Gas-Powered Generators (GPG) to provide dispatchable capacity and to serve as an effective 'transition technology' in the National Electricity Market (NEM) [8,9].

Potential gas shortages and soaring prices have prompted the Commonwealth Government to consider intervention in the market to secure domestic supply and ease supply pressures on consumers. In October 2017, a Heads of Agreement was reached between the Commonwealth and east coast LNG exporters to offer sufficient gas to meet projected shortfalls during 2018 and 2019 [10]. While this appears to have averted government intervention in the short-term and may ease near-term physical supply concerns, it does not guarantee relief from unaffordable prices nor does it provide a sustainable pathway for affordable energy in the eastern Australian market. The Australian LNG experience is,

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[1] Unless otherwise indicated, any reference to $ in the paper indicates Australian dollar. For the purposes of this paper a US Dollar to Australian dollar exchange rate of 0.8 is used.

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Nomenclature

Sets

D	Set of all gas demands
F	Set of all gas fields
N	Set of all gas nodes
N^d	Set of all domestic gas nodes
U	Set of all gas processing plants
L	Set of all gas pipelines
S	Set of all gas storages

Subscripts

$d \in D$	Gas demand
$f \in F$	Gas field
$u \in U$	Gas processing plant
$l \in L$	Gas pipeline
$n \in N$	Node
$s \in S$	Gas storage
$t \in T$	Time (days)

Parameters

$\rho_{d,t,n}$	Gas demand (GJ)
$C^p_{f,t}$	Cost of production ($/GJ)
$C^r_{u,t}$	Cost of processing ($/GJ)
$C^+_{l,t}$	Pipeline flow charge in positive direction ($/GJ)
$C^-_{l,t}$	Pipeline flow charge in negative direction ($/GJ)
$C^w_{s,t}$	Cost of withdrawing gas from storage ($/GJ)
$C^i_{s,t}$	Cost of injecting gas into storage ($/GJ)
$\eta_{d,n,t}$	Shortage cost ($/GJ)
$C^{p,max}_{l,n}$	Pipeline maximum flow capacity (GJ/day)
$C^{r,max}_{l,n}$	Processing facility maximum volume capacity (GJ/day)
$C^{ST,max}_{s,t,n}$	Storage facility maximum volume capacity (GJ)
$C^{ST,min}_{s,t,n}$	Storage facility minimum volume capacity (GJ)
$C^{S+,max}_{s,t,n}$	Storage facility maximum injection rate(GJ)
$C^{S-,max}_{s,t,n}$	Storage facility maximum withdrawal rate(GJ)
A^{yr}_f	Annual contracted amounts for a field (GJ)
R^{yr}_f	Annual maximum reserve depletion for a field (GJ)
D^N_t	Discount factor for network expansion scenario
C^I_Y	Investment cost of network expansion scenario
$LR^S_{s,t,n}$	Storage losses per interval (GJ)

Variables

$G^p_{f,t,n}$	Gas produced (GJ)
$G^r_{u,t,n}$	Gas processed (GJ)
$G^+_{l,t,n}$	Pipeline gas flow in positive direction (GJ)
$G^-_{l,t,n}$	Pipeline gas flow in negative direction (GJ)
$G^w_{s,t,n}$	Gas withdrawn from the storage
$G^i_{s,t,n}$	Gas injected from the storage
$G^H_{s,t,n}$	Gas held in storage
$\varepsilon_{d,n,t}$	Gas shortage
$\lambda_{t,n}$	Marginal (shadow) price at the node

however, not unique. Other markets around the world have also experienced similar impacts from being connected to the global gas market. Prior to the global LNG supply glut post-2013, major LNG buyers in Europe faced steep price increases as they were locked into long-term contracts indexed to crude oil prices. These had risen to levels above gas market fundamentals in their individual regions – with oil linked contracts pricing at 20–30% above hub prices in the UK [11].

The key question is then: do non-interventionist policy mechanisms exist within the eastern Australian gas market through which consumers can obtain relief from high gas prices?

The cost of the commodity itself is only one element of the price for the end consumer. Additional factors such as the cost of transport, storage processing and associated infrastructure are also important. The Victorian Declared Wholesale Gas Market (DWGM) is the only gas market on the east coast that provides users with firm gas transmission rights with costs recovered on a market-wide basis [12]. Other markets such as the Short-Term Trading Market (STTM) and the Gas Supply Hub (GSH) require shippers to negotiate and organise their own transportation arrangements with pipeline companies. Thus the development of solutions to gas affordability concerns require a consideration not only of gas supply and resource development but also the efficacy and costs of transport and infrastructure to bring the gas to market. As put by Summons et al. [13] "*Development of new upstream gas supply and effective competition in wholesale gas markets is linked to access to efficiently priced gas transportation, processing and storage services which in turn relies on a combination of efficient price signals and regulatory arrangements.*" [13]. Competition in wholesale gas market supply depends on efficient access to gas transportation, and the price points at which transportation and storage services are obtained. In the face of a tight supply-demand balance, the connectivity of gas markets takes on increasing importance. Improved interconnectivity can improve price transparency and signals by enhancing flexibility and accessibility in the market [14]. Other factors such as the broader competitive dynamic and market power of key participants such as producers and pipeliners can also play an important role, as highlighted by ACCC [1,15].

Fig. 1 outlines the current estimated cumulative gas supply curve for the east coast gas [16,17], based on the Petroleum Resources Management System classifications [18]. It is observed that cumulative demand over the next ten years exceeds currently developed 2P reserves and intersects reserves classified as 2P

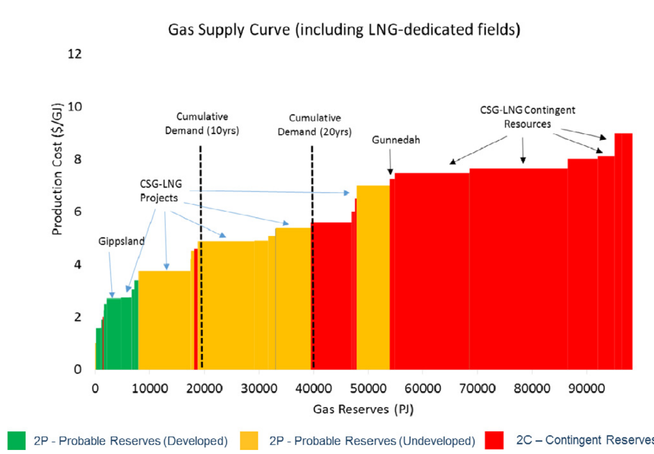

Fig. 1. East Coast Gas Supply Curve based on projections of reserves and production cost as per the AEMO 2017 Gas Statement of Opportunities [16].

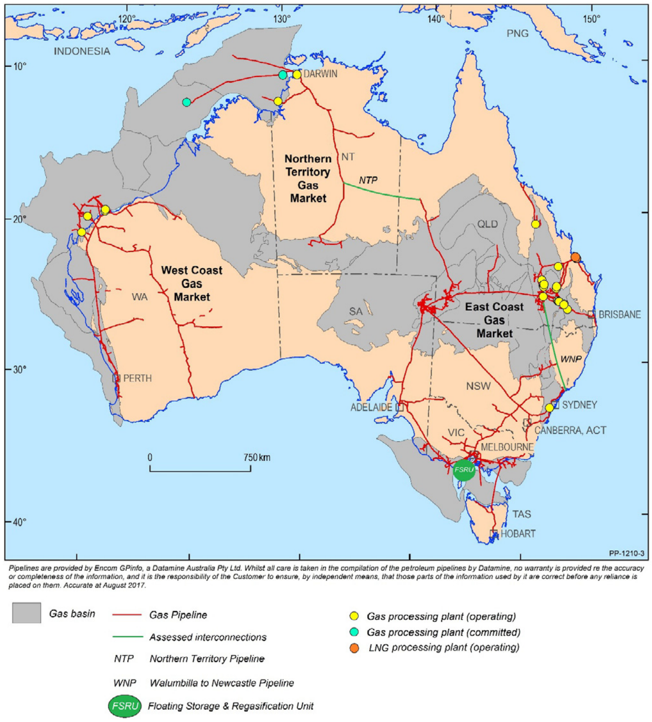

Fig. 2. Topology and map of major gas nodes and transmission pipelines in Australia. Pipeline projects examined in this study highlighted in blue, and the location of the FSRU indicated in black. Reproduced with the permission of Geoscience Australia and adapted by author[2].

undeveloped. Cumulative demand over twenty years intersects with higher 2C contingent resources. This indicates increasing tightness in supply, and provides the motivation for detailed examination of the supply dynamics and options to improve system balance. Despite market signals for additional supply, further development of gas resources in many states has been prevented by moratoria on unconventional gas development or the use of hydraulic fracturing techniques. Victoria also imposes a ban on onshore conventional gas development until 2020.

Long-term modelling studies are useful tools for future policy and infrastructure development. They can provide a quantitative assessment of the projected impact of policy decisions on the market. Least cost approaches provides useful information on the scale of price impacts and identify lower bounds to system costs [19].

This paper employs long-term modelling to assess the impact of network connectivity on gas prices and supply for Australian consumers, and potential flow-on impacts to the electricity market. The three interconnection pathways examined for the east-coast gas market as outlined in Fig. 2 are:

(i) Wallumbilla-Newcastle Gas Pipeline (WNP) linking the Wallumbilla hub in Queensland to Newcastle, New South Wales via Narrabri.
(ii) Northern Territory to Mt-Isa Pipeline (NTP) linking gas-rich Northern Territory to the eastern markets through Mt Isa, Queensland.
(iii) Floating Storage Regasification Unit (FSRU) in Victoria linking the eastern gas markets to the global LNG spot market.

The study solves a least-cost mathematical model of the east coast gas market, formulated as a Mixed-Integer Problem (MIP) using Energy Exemplar's PLEXOS® gas module.

Section 2 will describe the model, and discuss the methodology used in deriving the price and system impacts. The results of our quantitative analyses are provided in Section 3, while flow-on impacts to the electricity market are given in Section 4. A brief conclusion is provided in Section 5.

2. Methodology and data

The model is formulated as a least-cost constrained optimisation using Energy Exemplar's PLEXOS® gas module to balance supply and demand over the long-term subject to technical, operational and contractual constraints. The model is run as a linear program (LP) as it provides suitable approximation for modelling the system over a multi-year horizon [19,20]. The time length selected for this model is ten (10) years, reflecting a medium to long term commercial planning horizon.

The model topology incorporates 67 separate nodes, connected to fields, processing facilities, storage and/or demand, each identified as separate objects in the network. Demand for gas is separated into demand for electricity generators, mass-market users (residential, commercial and industrial) and LNG. LNG demand is further separated into contracted (inflexible) demand and flexible demand as outlined below. The gas transmission network is modelled but gas distribution and retail are not specified and are assumed to be incorporated within demand nodes. The linear program is implemented in Plexos (version 7.3 × 64 edition) using the Xpress MP Solver (version 7.1.1).

$$
\begin{aligned}
min \Bigg[& \sum_{f,t,n}\left(C^{p}_{f,t}G^{p}_{f,t,n}\right)+\sum_{u,t,f}\left(C^{r}_{u,t}G^{r}_{u,t,f}\right)+\sum_{l,t,n}\left(C^{+}_{l,t}G^{+}_{l,t,n}\right) \\
& +\sum_{l,t,n}\left(C^{-}_{l,t}G^{-}_{l,t,n}\right)+\sum_{s,t,n}\left(C^{w}_{s,t}G^{w}_{s,t,n}\right)+\sum_{s,t,n}\left(C^{i}_{s,t}G^{i}_{s,t,n}\right)+\sum_{d,t,n}\left(\eta_{d,n,t}\varepsilon_{d,n,t}\right)\Bigg]
\end{aligned}
\tag{1}
$$

The objective function is given in Equation (1), with a complete statement of the optimisation and constraints in Appendix B. The objective function models the cumulative costs of gas production, processing, transport (in reference and counter-reference directions), storage (withdrawal and injection) and shortage costs respectively. Key technical and operational constraints relate to conservation of mass, pipeline transmission and processing facility capacity, storage volumes and deliverability, while commercial constraints are based on minimum contracted quantities.

The modelling of additional network interconnections is undertaken through modification of the current network topology to add pipeline units in the case of (i) NTP (between the Mt Isa node and the Tennant Creek node) and (ii) WNP (Stage 1: between the Gunnedah node and Newcastle node and Stage 2: between the Gunnedah to Wallumbilla node) and an additional supply source in the case of (iii) FSRU (located at the Melbourne node).

2.1. Gas load

AEMO is the independent system operator for the DWGM, STTM and the GSH. AEMO publishes annual gas load for the east coast gas markets in its National Gas Forecasting Report (NGFR), the most recent edition of which was published in 2016 [21]. The Reference Case for this paper uses the 'Neutral' gas load of that report. We comment that our model assumes no further price elasticity of demand beyond those assumed by the market operator in

[2] Interconnections are not to scale, and are at indicative locations.

developing the neutral scenario of the National Gas Forecasting Report (NGFR). As such, the dynamic variability between gas demand and gas prices is not fully captured. However, we further comment that a neutral final aggregate demand is a reasonable approximation given only a fraction of total gas load – mostly GPG - is exposed to this elasticity. Further work as an extension of this study may explore a co-optimisation of gas and electricity markets to capture this dynamic.

LNG load for the eastern market are based on [22] which project total LNG load of around 1430PJ by 2020. In this study, LNG load is further broken down into contracted demand, and uncontracted (or spot) demand. Of the total LNG load, it is assumed that up to 295PJ may be available to spot markets or alternatively redirected domestically [23]. In addition, around 75PJ of gas volumes for Asia-Pacific LNG (APLNG) in FY2018 are available either for spot LNG demand or redirected towards domestic demand. This is partly driven by downward flexibility revisions in contracts, known as Downward Quantity Targets (DQT) [24]; [25]. This would amount to around 15% of annual estimated contracted gas requirements for APLNG.

2.2. Shortage price

The modelling of LNG demand and shortage pricing is an essential element of this study. The shortage price is the notional price of gas required when supply is not sufficient to meet demand. It represents the opportunity cost of gas supply and the value lost when there is a shortage. A shortage price of \$800/GJ was used for domestic demand and contracted LNG demand in the system, based on the market price cap in the DWGM and STTM.

Uncontracted LNG demand is assumed to be available to sell into either the Asian LNG spot market or the domestic market. The model assumes that this incremental production is only satisfied if the gas can be purchased in the market at a price below the breakeven or 'netback' price for that spot LNG at the LNG processing facility nodes. This aligns with the natural economic incentive of the LNG producers to profit-maximise [1,15] and is also consistent with the recent gas supply Heads of Agreement which requires LNG exporters to first offer any uncontracted gas into domestic markets. Thus the shortage price for uncontracted LNG demand is based on the netback price for spot LNG, using Asian LNG spot price forecasts over the next ten years [26] and associated liquefaction & transport costs [27] resulting in a price of \$8/GJ in the Reference Case, consistent with [3].

2.3. Initial reserves and production costs

Production costs for reserves are based on the AEMO Gas Statement of Opportunities (GSOO) 2017 except as indicated below:

- Production costs for prospective reserves are sourced from [23].
- The production cost for Mereenie 2P reserves are based on [28], with a cost adder for 2C reserves based on [17]. Production costs from Mereenie are expected to be low given the field's economic activities around its deposits of natural resources [29].

Initial supply from reserves was calculated using GSOO data (which uses an estimate as at 1 January 2016) and subtracting actual production to date based on information from the Gas Bulletin Board (GBB) [30].

The cost of supply for the FSRU is determined based on international LNG pricing dynamics adjusted for the cost of regasification. This study uses the ten year forecast for spot LNG set out in [26] which averages to approximately \$10/GJ, a \$2/GJ spread above the Queensland LNG breakeven price set out above.

2.4. Transmission, processing and regasification costs

Charges for use of existing infrastructure (including pipeline transmission, processing and storage) are based on data from Core Energy Group and AEMO [16]. For new interconnections, the published tariff is used where such data is available, or if the published charge is unavailable an estimate is used. Assumed pipeline transport charges are \$1.50/GJ for NTP and \$1.50/GJ for WNP [16], and assumed FSRU variable costs (including regasification and operating costs) are \$0.30/GJ based on Songhurst [31].

2.5. Discount rate

The nominal weighted average cost of capital used for the interconnectivity study is 6.4% calculated in accordance with Equation (2) and the following assumptions (see Table 1):

$$WACC = r_d(1-t)^*\left(\frac{D}{V}\right) + r_e\left(1-\frac{D}{V}\right) \tag{2}$$

3. Results and discussion

The Reference Case and scenarios are defined using the input data presented in Section 2. Each case will run the Reference Case under the current network topology and re-run additional scenarios based on additional network expansions as specified below:

1. Reference Case – Current network topology with no build options
2. Reference Case with the build of Northern Territory to Mt-Isa Pipeline (NTP)
3. Reference Case with the build of Wallumbilla to Newcastle Gas Pipeline (WNP)
4. Reference Case with the build of Floating Storage & Regasification Unit (FSRU)
5. Reference Case with the build of both NTP and WNP (NTP + WNP)

3.1. Reference case results

3.1.1. Price impacts

The impacts of network expansion on the marginal domestic price (weighted by demand at domestic nodes and excluding LNG delivery nodes) for each scenario Y is shown in Fig. 3, with the marginal domestic price calculated as per Equation (3) below.

$$\lambda_{t,Y} = \frac{\sum_{d,t,n\in N^d} \lambda_{t,n}\big|_Y \times \rho_{d,t,n}}{\sum_{d,t,n\in N^d} \rho_{d,t,n}} \tag{3}$$

Improved network interconnection between key regions can drive lower gas prices across the eastern seaboard of Australia, Price differentials of \$1.5–2/GJ are observed under the WNP scenario.

Table 1
Assumptions used for calculation of weighted average cost of capital.

Component	Value	Source
$\boldsymbol{r_d}$, cost of debt	5.6%	[6]
$\boldsymbol{r_e}$, cost of equity	11.0%	[5]
t, tax rate	30%	[7]
D/V, gearing ratio	60%	[10][a]

[a] The actual gearing of any project could exceed the regulator's benchmark of 60% in practice, based on financial and capital market conditions at the time.

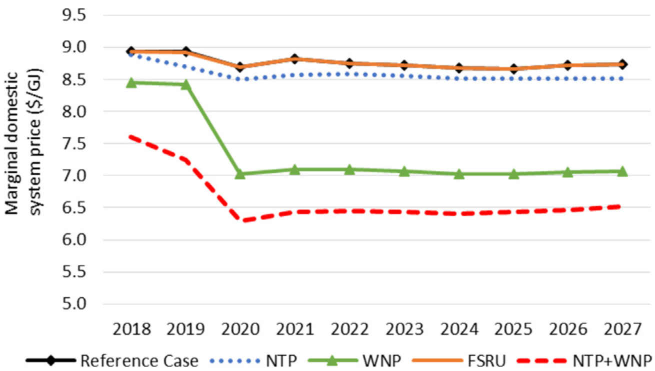

Fig. 3. Weighted average marginal price for all east coast domestic nodes, weighted by demand and excluding LNG delivery nodes.

Simulations of the build of NTP results in price differentials of less than \$0.2/GJ, which is significant when considered in light of the total pipeline capacity, domestic demand, and flow volumes.

Further suppression in prices is feasible for the NTP scenario, however, this is constrained by the transportation capacity of the NTP, which is assumed at 90 TJ/day or approximately 33PJ per annum. Gas from the Mereenie field is sufficient to satisfy demand at the Mt Isa node, with around 2 PJ of flows to Moomba (Fig. 4). The reduction in marginal price at Mt Isa is driven by production and transport cost differentials between Mereenie reserves and alternative supply, such as Cooper Eromanga. However, the impact of the NTP on marginal prices at other major nodes is minimal given the negligible volumes of Mereenie gas flowing down to Moomba.

The rationale for the WNP is to enable the Gunnedah/Narrabri gas reserves to access the market and to provide additional supply to the market. However, given the relatively high cost of production from these reserves, negligible amounts of gas (~0.02PJ) are predicted to reach the market from the Gunnedah basin over the modelling horizon. Nevertheless, once constructed the WNP is projected to be utilised at 50–60% of capacity over the modelling horizon as gas is transported from supply-rich Wallumbilla to Newcastle, and then to Sydney, a key demand zone.

Fig. 5 illustrates the cost of gas from coal seam gas (CSG) reserves in Queensland delivered to the Sydney node under the Reference Case and the WNP Case. WNP enables a more direct and cheaper access path for these reserves, allowing for cheaper prices (by up to \$2.60/GJ) at the Sydney node, a large demand centre. Thus, price reductions observed under the WNP Case (relative to the Reference Case) are primarily derived from interconnection rather than supply access to the Gunnedah basin. This indicates that the value of WNP is less attributable to its ability to provide access to the Gunnedah supply basin, but rather the ability to provide a direct and optimal transportation route between Wallumbilla and the Sydney/Newcastle demand region.

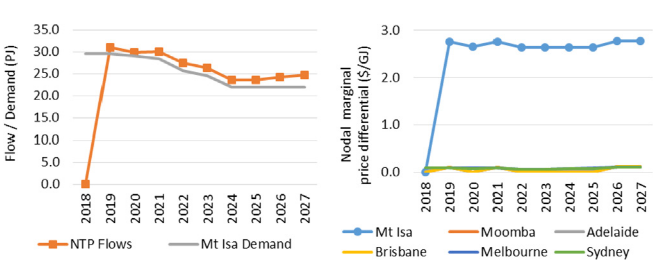

Fig. 4. Pipeline flows across NTP and CPG relative to demand at Mt Isa (LHS) and nodal marginal price differentials (between NTP and Reference cases) at various locations.

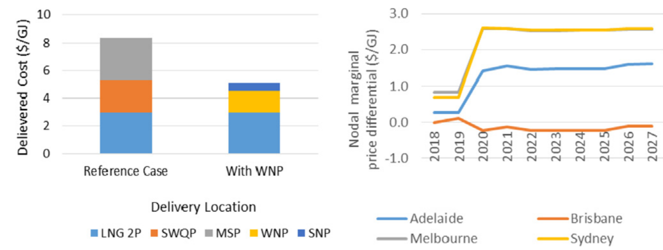

Fig. 5. Delivered cost of CSG reserves at the Sydney node (LHS) and nodal marginal price differentials (between WNP and Reference cases) at various locations.

No material price reductions from the FSRU project is observed as the model assumes a fixed price differential between the cost of LNG purchases at the supply node and the netback price at Gladstone based on expected liquefaction, shipping and regasification costs. As a result of this differential, the optimisation does not flow any gas from the FSRU under the base demand scenario as it is more economic to curb LNG spot sales. Under these assumptions, FSRU is unlikely to provide any material price reduction benefit for the system.

However, the methodology employed in this study may not fully represent all of the market and system dynamics that are relevant to the FSRU project. An important part of the rationale for the FSRU is to capitalise upon inter-regional spot pricing and arbitrage opportunities between domestic and international prices especially given seasonal timing differences between North Asia and Australia. These factors and mechanisms are not incorporated into this analysis.

The combined scenario involving the construction of the NTP and WNP (in Fig. 3) projects domestic marginal prices that are around \$0.5/GJ lower than the scenario involving the construction of WNP only. Additional supply from the Mereenie fields reduces the amount of production required from more expensive LNG reserves to meet domestic demand with approximately 232 PJ of production offset over the simulation horizon. This allows most major nodes to source cheaper gas than would otherwise have been the case, especially the Adelaide node which benefits from additional marginal supply from Moomba. The reduced supply from LNG nodes also reduces the flows across the WNP by approximately the same amount. NTP flows are also reduced over the forecast horizon from 27 PJ per annum to 26 PJ per annum if both NTP and WNP are constructed, with average capacity utilisation falling from 82% to 79%.

3.1.2. Net system benefits

The relative system benefit to cost ratio is defined in Equation (4) as Φ, which quantifies the price impact of network expansions on the domestic market relative to the cost of expansion. Φ is defined below for each interconnection scenario (Y) and is relative to the Reference Case (R). The system benefits are reflected in the numerator as the present value (PV) of the system for domestic nodes. This is calculated as the differential between nodal price outcomes for scenario Y and reference case R multiplied by the demand at each domestic node. The costs to the system are reflected in denominator as the total build costs of each network expansion.

$$\Phi_{\mathrm{Y}} = \frac{\sum_{d,t,n \in N^d} D_t^N \left(\lambda_{t,n}\big|_{\mathrm{Y}} - \lambda_{t,n}\big|_{R}\right)\rho_{d,t,n}}{C_{\mathrm{Y}}^I} \tag{4}$$

Values of Φ are shown for each scenario in Fig. 6.

The relative system benefits for NTP when compared against the build cost of the new pipeline are marginal – with net system

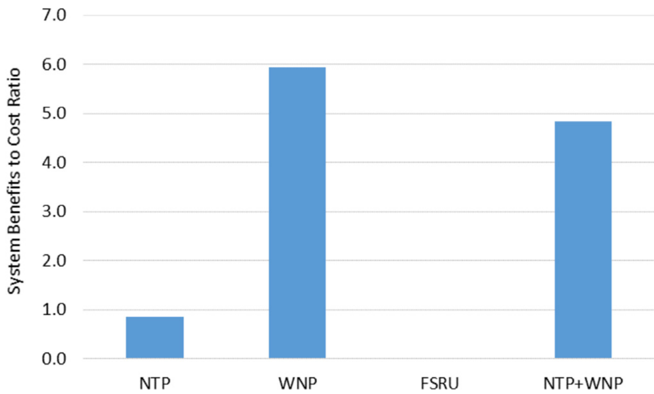

Fig. 6. Relative system benefits to cost ratio for interconnection scenarios: NTP, WNP, FSRU, NTP + WNP.

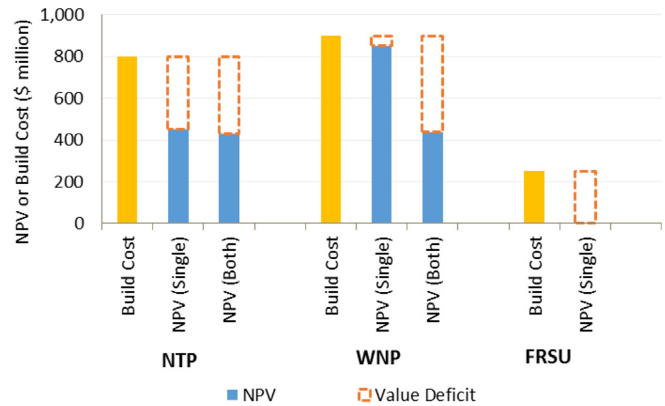

Fig. 7. Net investor benefits relative to investment cost for interconnection scenarios: NTP, WNP and FSRU calculated as a net present value of EBITDA over a ten year horizon.

benefit ratio of less than one. The only reserves assumed to be available for domestic supply through NTP is the Mereenie reserves in the Northern Territory. While the cost of Mereenie supply is competitive, the size of the Mereenie reserves are assumed to be only 241 PJ, and the simulation forecasts that this field will be close to depleted after 10 years without further development. An expansion of domestic supply options in the Northern Territory combined with a corresponding increase in NTP capacity could allow for more material price benefits.

For the WNP, the system benefits to cost ratio of 6.0 reflects strong system benefits from the interconnection driven by the reduction in pricing across domestic nodes from the connection between Wallumbilla and Newcastle. These benefits are contingent upon gas producers being able to develop and extract production from reserves, including further reserves from CSG fields in Queensland.

3.1.3. Investor benefits

The development of interconnection projects in the gas market is primarily reliant upon private investment and financing. This relies upon the risk-adjusted returns for the project being sufficiently attractive to justify participation from private investors from an equity and debt perspective. Thus, for each interconnection project, the investor net present value (NPV) is calculated based on the expected pipeline flows and assumed tariffs, and an earnings before tax, interest, depreciation and amortisation (EBITDA) margin of 80% [32]. A pipeline terminal value is included in the NPV calculation, consistent with the long-term nature of the investment based on terminal EBITDA multiple of 15.0 times multiplied by the average cash flows over the last three years of the planning horizon. A value deficit is created where the NPV is not sufficient to cover the costs of investment, while a value excess is created where the NPV is greater than the investment cost.

This metric quantifies whether an investor in the interconnection project will be able achieve sufficient risk adjusted returns under an optimised system plan. In practise, infrastructure projects such as pipeline developments are typically financed with long term offtake contracts in place to underwrite the investment. The potential revenue from a system optimisation model provides guidance to the achievability of these contracts in a competitive market.

Fig. 7 plots the net present value to an investor in each network expansion. For NTP and WNP, it also examines the impact on investor value if only the individual pipeline under consideration is built (NPV-Single) as well as the case of both pipelines being built (NPV-Both).

For the NTP scenario, the NPV-Single results indicate that the net present value of investor cash flows is $452 million relative to an estimated investment cost of $800 million, resulting in a deficit of $348 million. This is despite average annual capacity utilisation of around 94% in 2019, declining to around 75% by 2027. The deficit could be driven by a multitude of factors including the project proponent's willingness to accept a lower cost of capital for the project, a higher assumed terminal value or actual costs being below assumed figures. It may also indicate a potential ‘loss-leader’ strategic position to allow the business rationale for further connectivity between the Northern Territory and the east coast markets to develop.

For the NPV-Both scenario, the value deficit for investors in NTP is $369 million reflecting slightly lower assumed pipeline flows across the NTP under a scenario where both NTP and WNP are built.

For WNP, the NPV-Single simulation indicates that the net present value of investor cash flows is $851 million relative to an estimated investment cost of $900 million, resulting in a deficit of $49 million reflecting a reasonable value proposition for investors in WNP.[3] This is an important result as it indicates that rationale for WNP in the simulations are supported both from a system perspective as well as an investor perspective, both of which are important for facilitating pipeline development. However, in the NPV-Both case WNP suffers a notable decline in value with a net present value of investor cashflows of $437 million relative to an estimated investment cost of $900 million, resulting in a deficit of $463 million. WNP average flows over the horizon decline from 51 PJ per annum at an average pipeline capacity utilisation of 60% to 26 PJ per annum with utilisation at 31%. The reduction in flows from WNP is driven by the presence of NTP. The core impacts presented in Figs. 8 and 9 can be summarised as follows:

- NTP allows gas to flow gas from the Mereenie field to Mt Isa, serving Mt Isa demand.
- Higher flows across the Moomba-Adelaide (MAPS) pipeline to Adelaide implying that gas production near Moomba is diverted south instead of servicing northern demand.

[3] A near-term WACC sensitivity was also conducted using a 70% gearing ratio, 4.3% cost of debt and a 7.0% cost of equity, resulting in an overall WACC of 4.2%. This sensitivity increased the System Benefits to Cost Ratio (SBC) of all investments by approximately 9–13%. The largest increase was observed for WNP, where the SBC increased to 6.7, whereas SBC for the NTP and NTP + WNP cases increased to 1.0 and 5.4 respectively. Under the sensitivity, the value deficit for NTP also reduces to approximately $272 million, while WNP shifts to a value excess of $84 million under the single build cases. Outcomes for FSRU do not change given there are no significant observed flows under this methodology.

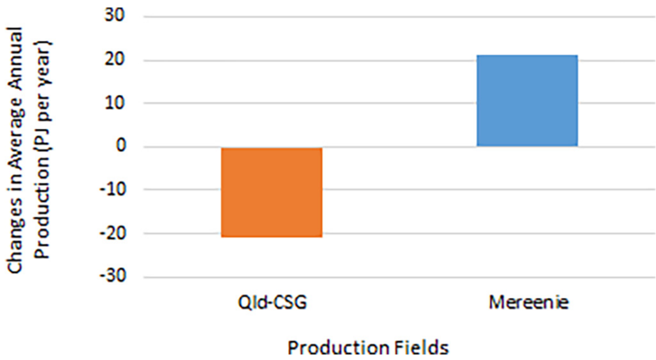

Fig. 8. Changes in average gas production at key fields between NTP + WNP and WNP cases over a ten-year modelling horizon.

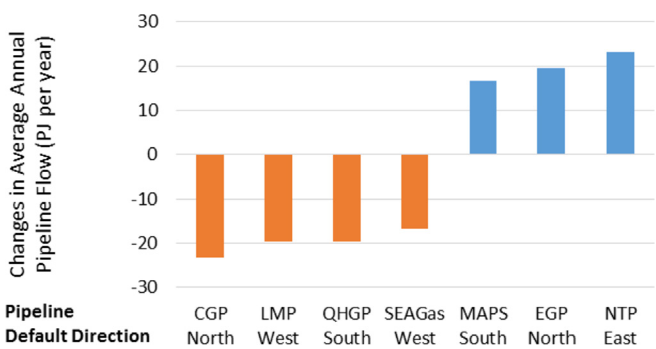

Fig. 9. Changes in average gas flows at key pipelines between NTP + WNP and WNP cases over a ten-year modelling horizon.

- Lower flows across the SEA gas pipeline suggesting that a portion of flows across WNP that would have been used to service Adelaide are now not needed; and
- Corresponding reductions in production from the Queensland CSG fields which would have flowed across WNP to meet southern demand.
- Increased northerly flows across the Eastern Gas Pipeline (EGP) to meet Sydney demand with corresponding reductions in western flows across the Longford to Melbourne Pipeline (LMP). This implies that under the NTP + WNP scenario, increased amounts of gas from Longford is used to supply Sydney demand.

4. Electricity market implications

This section assesses whether lower gas prices can contribute to lower electricity prices, given its role as a fuel source for electricity supply. Gas powered generation (GPG) is an important source of electricity generation, comprising 19% of registered capacity in the NEM and 7% of generation in FY2016. It is also seen as an important source of flexible generation given its ability to ramp up and down quickly which is important in peak demand periods as well as providing system firming benefits due to increasing penetration of intermittent and variable renewable generation in the market [33]. AEMO has also highlighted shortfalls in the gas market could result in potential shortfalls in electricity generation [16].

The methodology involved using AEMO price setter data for the NEM by fuel source. The proportionate electricity price impact (Z) on the NEM regional price is calculated in Equation (5). Z is calculated for each NEM Region (Ω) with respect to each interconnection scenario (Y) relative to the Reference Case (R).

$$Z_{Y,\Omega} = \frac{\sum_F E_{\Omega,F}\,\psi_{\Omega,F}\,\pi_{\Omega,F,\,Y}}{E_\Omega} \tag{5}$$

where: $E_{\Omega,F}$ is the average marginal electricity price set by fuel source F for regionΩ

$\psi_{\Omega,F}$ is the proportion of time that the electricity price for region Ω is set by fuel source F
$\pi_{\Omega,F}$ is the price adjustment factor for fuel source F for region Ω.

The analysis is conducted on historical price setting data from end June 2017 to end September 2017 under two scenarios: Scenario 1 assumes that lower gas prices flow through to lower bids by GPG on a pro-rata basis; while Scenario 2 assumes price-taking coal generators also revise bids downwards on a similar basis, a pattern which has been observed historically. For Scenario 1, $\pi_{\Omega,F,Y} = \lambda_{ave,Y}/\lambda_{ave,R}$ for the gas fuel source, and 1 for all other fuel sources. For Scenario 2, $\pi_{\Omega,F,Y} = \lambda_{ave,Y}/\lambda_{ave,R}$ for gas and coal fuel sources, and 1 for all other fuel sources.

Under Scenario 1, electricity price reductions of 3%–8% are observed while price reductions of up to 12%–19% are observed for Scenario 2 (see Table 2). The analysis presented here does not incorporate dynamic interactions between electricity and gas markets. However, given the potential for notable electricity price reductions comprehensive gas-electricity co-optimisation analyses involving long-term dynamic scenario planning may be justified as an extension of this study.

5. Conclusions

This paper investigates the impact of market interconnectivity on long-term gas prices, and the potential for flow-on reductions in electricity prices across the eastern regions of Australia.

Our model is best suited to assessment of long-lived fixed infrastructure projects such as pipelines. Non-fixed interconnectivity projects may also be able to benefit from temporal/seasonal and intra-regional price spreads, and can also location-shift if price dynamics change. The modelling results show that improved connectivity can provide reductions of $2/GJ or more in average gas prices across the eastern seaboard of Australia. The Wallumbilla-Newcastle Gas Pipeline (WNP) is seen to have the most value from a system perspective as well as providing investors with sufficient return on capital over the 10-year modelling horizon. The Northern Territory to Mt-Isa Pipeline (NTP) while resulting in some price reduction had a limited impact given its capacity. The results also show that further development of additional gas

Table 2
Estimated changes in electricity prices in the NEM from current levels flowing from reductions in gas prices.

Scenario 1: Lower Prices for Gas-Fired Generators

Scenario	NSW	QLD	SA	VIC
With NTP	0%	0%	1%	1%
With WNP	2%	2%	6%	4%
With NTP + WNP	3%	3%	8%	6%

Scenario 2: Coal Generator 'Price Taker' Response

Scenario	NSW	QLD	SA	VIC
With NTP	1%	2%	1%	1%
With WNP	12%	13%	10%	9%
With NTP + WNP	18%	19%	15%	13%

reserves in the Northern Territory along with capacity expansion is required in order to improve the market and investment benefits of the NTP. This further emphasises the impact that moratoria on gas project development have on gas prices and affordability.

Finally, the study also assesses flow-on impacts to the NEM, and initial results show that reductions in electricity prices are possible (potentially up to 13–19% depending on regions and generator bidding behaviour). However, further dynamic modelling would be required to fully quantify these flow-on impacts to the NEM.

Declarations of interest

None

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Appendix A. : Glossary

ACCC	Australian Consumer and Competition Commission
AEMO	Australian Energy Market Operator
APLNG	Asia Pacific LNG
CGP	Carpenteria Gas Pipeline
CSG	Coal Seam Gas
DQT	Downward Quantity Target
DWGM	Declared Wholesale Gas Market
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
EGP	Eastern Gas Pipeline
FSRU	Floating Storage Regasification Unit
GJ	Gigajoule
GLNG	Gladstone LNG
GPG	Gas Powered Generation
GSG	Gas Supply Guarantee
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
JKM	Japan Korea Marker
LMP	Longford to Melbourne Pipeline
LNG	Liquefied Natural Gas
Mtpa	Million tonnes per annum of LNG
MMBtu	Million British Thermal Units
MAPS	Moomba to Adelaide Pipeline System
NGFR	National Gas Forecasting Report
NTP	Northern Territory Pipeline
NPV	Net Present Value
PJ	Petajoule
QCLNG	Queensland Curtis LNG
QGP	Queensland Gas Pipeline
RBP	Roma Brisbane Pipeline
ROI	Return on Investment
SGX	Singapore Exchange
STTM	Short Term Trading Market
SWQP	South West Queensland Pipeline
TJ	Terrajoule
UQT	Upward Quantity Target
WNP	Wallumbilla to Newcastle Pipeline

Appendix B. Model optimisation

The full mathematical formulation of the linear program used in this paper is described below.

Objective function:

$$\begin{aligned} min \Bigg[& \sum_{f,t,n}\left(C^{p}_{f,t}G^{p}_{f,t,n}\right) + \sum_{u,t,f}\left(C^{r}_{u,t}G^{r}_{u,t,f}\right) + \sum_{l,t,n}\left(C^{+}_{l,t}G^{+}_{l,t,n}\right) \\ & + \sum_{l,t,n}\left(C^{-}_{l,t}G^{-}_{l,t,n}\right) + \sum_{s,t,n}\left(C^{w}_{s,t}G^{w}_{s,t,n}\right) + \sum_{s,t,n}\left(C^{i}_{s,t}G^{i}_{s,t,n}\right) \\ & + \sum_{d,t,n}\left(\eta_{d,n,t}\varepsilon_{d,n,t}\right)\Bigg] \end{aligned}$$

Constraints

- Conservation of mass as: Gas demanded at each node plus gas withdrawn from the node (either via pipeline or storage) must be equivalent to gas injected into the node, (either from a processing facility, pipeline or storage) plus the gas shortage at the node.

$$\begin{aligned} & \sum_{d}\rho_{d,t,n} + \sum_{l}\left(G^{+}_{l,t,n} - G^{-}_{l,t,n}\right) + \sum_{s}\left(G^{w}_{s,t,n} - G^{i}_{s,t,n}\right) \\ & = \sum_{u}G^{r}_{u,t,n} + \sum_{d}\eta_{d,n,t} \end{aligned}$$

- Maximum pipeline flow: The net flow into each pipeline must be less than or equal to the pipeline capacity.

$$\sum_{n}\left(G^{+}_{l,t,n} - G^{-}_{l,t,n}\right) \le C^{p,max}_{l,n}$$

- Maximum processing facility volume: The volume through each gas processing facility must be less than or equal to the capacity of the processing facility.

$$\sum_{n}G^{r}_{u,t,n} \le C^{r,max}_{l,n}$$

- Gas in storage: The volume stored in a gas facility at time t must be equivalent to the gas held in storage at t-1 plus storage injections minus storage withdrawals minus losses.

$$G^{H}_{s,t,n} = G^{H}_{s,t-1,n} + G^{i}_{s,t,n} - G^{w}_{s,t,n} - LR^{S}_{s,t,n}$$

- Maximum and minimum storage volumes: The volumes of gas held in each storage facility must be less than or equal to the maximum storage capability of the facility, and more than the minimum storage requirement of the facility.

$$G^{H}_{s,t,n} \le C^{ST,max}_{s,t,n}$$

$$G^{H}_{s,t,n} \ge C^{ST,min}_{s,t,n}$$

- Maximum storage injections and withdrawals: The volume of gas injected into storage must be less than or equal to the maximum storage injection rate. The volume of gas withdrawn from storage must be less than or equal to the maximum storage withdrawal rate.

$$G^{i}_{s,t,n} \leq C^{S+,max}_{s,t,n}$$

$$G^{i}_{s,t,n} \leq C^{S-,max}_{s,t,n}$$

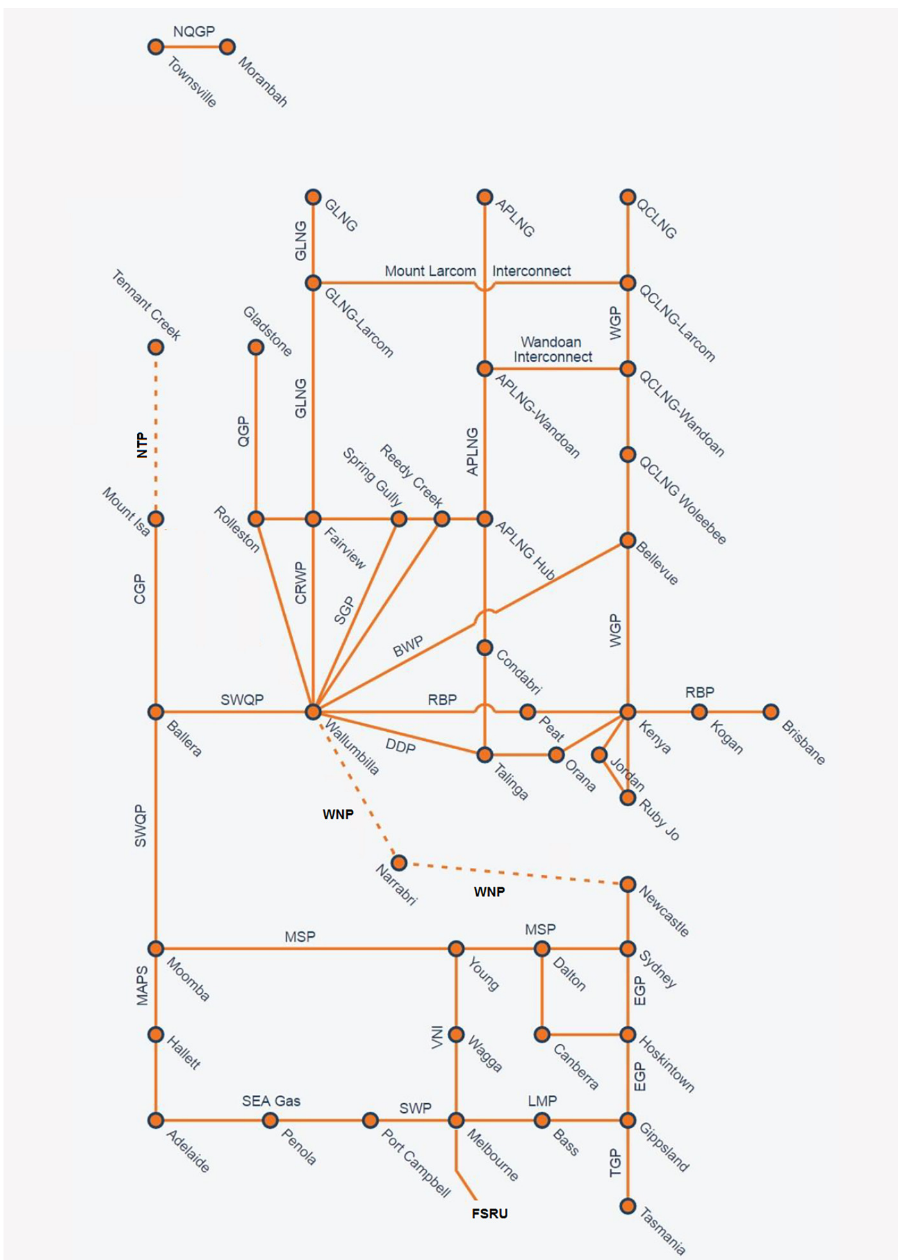
- Contracts: The amount of gas produced from a field must meet or exceed its contracted amounts

$$\sum_{yr} G^{p}_{f,t,n} \geq A^{yr}_{f}$$

- Reserve depletion: The amount of gas produced from a field must be less than the maximum allowed reserve depletion

$$\sum_{yr} G^{p}_{f,t,n} \leq R^{yr}_{f}$$

Appendix C. Gas network topology



Adapted from AEMO Gas Statement of Opportunities 2017 [16].

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