GOLDFIELDS GAS PIPELINE

Access Arrangement Revision Proposal

Supporting Information: Attachment 3

CEG Competition Economists Group
Cost Allocation for the Goldfields Gas Pipeline

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Dr Tom Hird

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1 Introduction

1. My name is Dr Thomas Hird and I am a Director of CEG Asia Pacific. This report has been prepared by CEG on behalf of Goldfields Gas Transmission Pty Ltd (GGT), which is currently preparing revisions to its Access Arrangement for the Goldfields Gas Pipeline (GGP). Parts of the GGP are "covered" under the *National Gas Access (WA) Act 2009* – which gave effect to the *National Gas Law* (NGL) – and others are not. The parts of the pipeline that are not "covered" are expansions that occurred after the original pipeline had been constructed. These "uncovered" expansions are not subject to by the Access Arrangement and include:

   - additional compressors installed at Paraburdoo, Wyloo West and Ned's Creek after the 2005 Access Arrangement was agreed; and
   - a more recent expansion for Rio Tinto Iron Ore and BHP Billiton Iron Ore, which is very close to completion.

2. When GGT's Access Arrangement was last revised,[1] significant consideration was given to the way in which the capital and operating costs that were common to both the covered and uncovered capacity should be apportioned between customers pursuant to the Gas Code,[2] which preceded the NGL. The issue ultimately turned on whether the services associated with the uncovered expansions were "services provided by means of a Covered Pipeline" within s.10.8 of the Gas Code. The Economic Regulation Authority (ERA) concluded that they were not and that decision was upheld on appeal.[3] As a consequence:

   - the capital costs of those parts of the uncovered additional compressors at Paraburdoo, Wyloo West and Ned's Creek were not included in the capital base when the current reference tariff was determined; and
   - the costs of operating and maintaining the additional compressors were excluded from non-capital costs, i.e., the directly attributable non-capital costs and a share of common operating costs attributable to those compressors.

3. The key implication of this cost allocation methodology is that, when new customers are added to the pipeline by way of uncovered expansions, the customers procuring covered services have not been attributed a reduced portion of the costs that are common across both customer groups. Most notably, the customers of the covered

[1] The process for the most recent revisions to the Access Arrangement was initiated on 23 March 2009. The appeal decision of the Electricity Review Board (discussed below) was dated 22 November 2011.

[2] More formally: *The National Third Party Access Code for Natural Gas Pipeline Systems*.

[3] Electricity Review Board, *Application for review of the decision by the Western Australian Economic Regulation Authority published on 5 August 2010 to approve its own revised Access Arrangement for the Goldfields Gas Pipeline*, 22 November 2011.

pipeline continue to be allocated 100% of the costs of the pipeline itself – even though the new customers are also using it. GGT has proposed to retain this approach in its revised Access Arrangement. This would clearly have complied with the Gas Code but, as we noted above, the Code has been supplanted by the NGL.

4. In this context, GGT has asked me to provide an independent expert assessment of the methodology against the economic principles contained in the NGL – most notably the National Gas Objective (NGO) and the associated revenue and pricing principles. I do so in the remainder of this report, which is structured as follows:

   - **section two** provides some relevant background on covered and uncovered parts of the GGP and the way in which GGT proposes to allocated costs that are common across these segments;
   - **section three** describes the concepts of sunk costs, marginal costs and common costs as they apply in the context of a gas transmission pipeline, which are of central relevance to the efficiency of pricing;
   - **section four** explain why, other things equal, economic efficiency requires the price for a commodity to reflect the marginal cost of producing it, and the potential implications of this for the efficient allocation of common costs; and
   - **section five** concludes.

5. In preparing this report I have been assisted by my colleague Hayden Green.[4] Notwithstanding this assistance, the opinions in this report are my own and I take full responsibility for them. I have read the Guidelines for Expert Witnesses in Proceedings of the Federal Court of Australia[5] and confirm that I have made all inquiries that I believe are desirable and appropriate and no matters of significance that I regard as relevant have, to the best of my knowledge, been withheld.

4 Hayden is an Associate Director at CEG. He holds a Bachelor of Commerce with First Class Honours in economics and a Bachelor of Laws with Honours from the University of Auckland, New Zealand.

5 M E J Black, Chief Justice, *Expert Witnesses in Proceedings in the Federal Court of Australia*, 25 September 2009.

2 Background

6. In this section I provide some background on the covered and uncovered parts of the GGP and the way in which the costs that are common across them have been treated under the previous legislative framework. I then summarise the cost allocation methodology that GGT proposes to employ for the coming access arrangement period and the new legislative requirements against which that approach must be assessed.

2.1 Cost allocation under the Gas Code

7. The GGP runs some 1,378km from Yarraloola, in the Pilbara, to Kalgoorlie. It supplies a relatively small number of large industrial customers, including mines or firms serving mines, such a gas fired electricity generators. When the 2005 Access Arrangement was approved, there were four compressors operating - at Yarraloola, Ilgarari, Wiluna and Paraburdoo (the "Initial Compressors"). At that time, the Initial Compressors serviced the entire capacity of the pipeline, which was some 109 TJ/day – all of which was covered under the previous Gas Code.

8. After the 2005 Access Arrangement commenced, additional compressors were installed at Paraburdoo, Wyloo West and Ned's Creek. As a result of the installation of these additional compressors (the "Additional Compressors"), the pipeline was able to transport an additional 49 TJ/day of gas. GGT elected for these additional tranches of capacity to remain uncovered. It entered into contractual arrangements with users to transport or haul gas utilising that new uncovered capacity that sat outside the Access Arrangement.

9. The additional services provided using the uncovered capacity were, in a physical sense, similar to those provided under the Access Arrangement for the covered capacity. The gas that was subject of the contracts for the uncovered capacity and the gas that was the subject of the Reference Service were transported using the same physical infrastructure (i.e., the pipeline itself), the compressors (both initial and additional) and the related control systems, etc.

10. When the Access Arrangement was last revised,[6] significant consideration was given to the way in which the capital and operating costs that were common to both the covered and uncovered capacity should be apportioned between customers pursuant to the Gas Code.[7] Customers of the covered pipeline – most notably BHP Billiton Nickel West Pty Ltd (BHPB) – argued that a share of these common costs

[6] The process for the most recent revisions to the Access Arrangement was initiated on 23 March 2009. The appeal decision of the Electricity Review Board (discussed below) was dated 22 November 2011.

[7] More formally: *The National Third Party Access Code for Natural Gas Pipeline Systems*.

should be excluded from the total revenue requirement in the Access Arrangement and recovered from the customers of uncovered services. BHPB contended that:

- the reference tariff should be designed to recover the whole of the costs of the initial compressors but *only a share* of the costs of the pipeline, rather than all of the costs of the pipeline; and
- the remaining part of the costs of the pipeline should be attributed to the additional services (i.e., the services provided using the uncovered capacity) and should not be recovered by the reference tariff.

11. In its Final (and Further Final) Decision the ERA concluded that such an approach was not permitted under the Gas Code. The issue ultimately turned on whether the services associated with the uncovered capacity of the pipeline were "services provided by means of a Covered Pipeline" within s.10.8 of the Gas Code. The ERA concluded that they were not. BHPB then appealed that decision, but the ERA's approach was upheld by the Electricity Review Board (ERB).[8] To comply with the directions of the ERB:

- the capital costs of those parts of the uncovered Additional Compressors (at Paraburdoo, Wyloo West and Ned's Creek) were not included in the capital base when the current reference tariff was determined; and
- the costs of operating and maintaining the Additional Compressors were excluded from non-capital costs, i.e., the incremental non-capital costs attributable to those uncovered services.

12. The key implication of this cost allocation methodology is that, when new customers have been added to the pipeline – most notably by way of uncovered expansions – the existing customers procuring covered services have not been attributed a reduced portion of the pipeline costs that are shared with those new customers. The existing customers continued to be allocated 100% of the costs of the pipeline itself – even though the new customers were also using it.

2.2 Cost allocation for Revised Access Arrangement

13. GGT is currently preparing its latest revisions to the Access Arrangement for the Goldfields Gas Pipeline (GGP). It intends to apply the same cost allocation methodology to determine reference tariffs for covered services for the coming access arrangement period. Specifically, GGT is proposing to determine the total revenue as the total cost of providing pipeline services using only the covered pipeline. This is to be the total of the costs of providing services to the joint

8 Electricity Review Board, *Application for review of the decision by the Western Australian Economic Regulation Authority published on 5 August 2010 to approve its own revised Access Arrangement for the Goldfields Gas Pipeline*, 22 November 2011.

venturers and the reference and negotiated services of the GGP access arrangement, calculated as:

- the return on the projected capital base of the covered pipeline;
- depreciation of the assets comprising the covered pipeline;
- the cost of corporate income tax estimated using the forecast revenue from the provision of the reference and negotiated services provided using the covered pipeline; and
- the forecast costs of operating the covered pipeline.

14. The total revenue for the covered pipeline will consequently exclude:

- the capital costs of the additional compressors;
- the capital costs of the recent expansion for Rio Tinto Iron Ore and BHP Billiton Iron Ore – an expansion which GGT has elected be uncovered (an election to which the ERA gave its consent on 30 May 2014); and
- the costs of operating and maintaining the additional compressors and the recent expansion for Rio Tinto Iron Ore and BHP Billiton Iron Ore, i.e., the incremental non-capital costs attributable to those uncovered services.

15. This approach would clearly have complied with the requirements of the Gas Code. However, while the previous revision process was still on foot the existing legislation was amended substantially by the *National Gas Access (WA) Act 2009* ("2009 Act"), which essentially gave effect to the NGL and *the National Gas Rules* (NGR) in Western Australia. GGT's latest revision application will therefore be assessed against the requirements in the NGL and the NGR.

2.3 The National Gas Law and Rules

16. The NGL contains a single, overarching objective that has a primary focus on economic efficiency. It is intended to be a precise, timeless representation of the overarching purpose of the economic regulatory framework. This National Gas Objective is contained in section 23 of the NGL, which states that:

> *"The objective of this law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."*

17. The NGL also contains a number of more specific "Revenue and Pricing Principles" that govern the determination of GGT's total revenue requirement and its prices for covered services, subject of course to the overarching National Gas Objective. These principles are contained in section 24 of the NGL and are as follows:

- *"A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in:*
  - *providing reference services; and*
  - *complying with a regulatory obligation or requirement or making a regulatory payment.*
- *A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes:*
  - *efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*
  - *the efficient provision of pipeline services; and*
  - *the efficient use of the pipeline.*
- *Regard should be had to the capital base with respect to a pipeline adopted—*
  - *in any previous—*
    - a. *full access arrangement decision; or*
    - b. *decision of a relevant regulator under section 2 of the Gas Code;*
  - *in the NGR.*
- *A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.*
- *Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.*
- *Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services."*

18. In the remainder of this report, I consider whether the cost allocation methodology that GGT has proposed to apply is likely to promote the National Gas Objective and comply with the Revenue and Pricing Principles set out in the NGL. I begin by describing some of the basic cost concepts that are of central relevance to the determination of efficient gas transmission prices, including the important distinction between the "sunk" costs of existing assets and the incremental cost of extensions or expansions.

3 Cost concepts

19. Before the efficiency of GGT's proposed cost allocation approach can be properly comprehended, it is helpful first to understand the concepts of sunk costs, marginal costs and common costs which are of central relevance to the efficiency of pricing. I describe these concepts in this section and consider how they apply in the specific context of a natural gas transmission pipeline.

3.1 Sunk costs

20. Sunk costs are defined as any expenditure on durable or specific factor inputs such as plant and machinery which cannot be used for other purposes or easily be resold.[9] The majority of the assets that comprise a gas transmission pipeline will be sunk for all practical purposes. Gas transmission assets tend to be big, expensive and highly specific (there are few, if any productive alternative uses for a gas pipeline once installed). That being the case, it will rarely (if ever) be efficient for a pipeline owner to relocate or sell pipeline assets for alternative uses.

21. Sunk costs relate to investment decisions that have already been made and for which there is now no way to reduce the cost or change the nature of those outlays. An essential characteristic of sunk costs is that they should have *no effect* on future production and pricing decisions.

22. For example, consider an asset owner deciding whether to cease supplying a service. The sunk costs associated with supplying that service would not be avoided with cessation of the service and are, therefore, irrelevant to efficient decision making. The asset owner will efficiently continue to provide the service so long as revenues from the service exceed the costs that would be avoided if she no longer provided it.

23. Similarly, an asset owner considering whether to expand a service offering should ignore already sunk costs when making this decision. Efficient decision making requires that the asset owner focus solely on the prospective costs and revenues associated with the expanded service offering – ignoring past expenditures that cannot be avoided prospectively. I elaborate below.

3.2 Marginal costs

24. In very simple terms, marginal cost is the additional cost that a firm incurs (avoids) by increasing (reducing) output by a specified increment, i.e., the cost of meeting an incremental increase in demand or providing a new service.[10] In the context of a gas

9 Collins Dictionary of Economics, 2nd Ed, Pass & Lowes.

10 Strictly, marginal cost is the first derivative of a firm's production cost function, with respect to output. However, its practical application involves the measurement of the change in a firm's cost of production

transmission pipeline, in the short term, demand must be met using the existing assets, i.e., the existing pipeline, compressors, etc. The short run marginal cost (SRMC) of transmitting gas depends upon whether or not the existing assets are capable of meeting all demand:

- when all demand can be met using the existing pipeline capacity, the SRMC of supplying gas is relatively low and may be very close to zero (say just the cost of running existing compressors more intensively to meet additional demand); but
- when customers demand more gas than it is possible to deliver using the existing assets – i.e., when the pipeline becomes congested, then:
  - it is no longer possible to meet an incremental increase in demand in that location with increased supply; and
  - the SRMC of gas transmission to one customer includes the value foregone by other customers who cannot be served as a consequence, e.g., the costs of using more expensive fuel sources or curtailing downstream production.

25. In the long run, incremental changes in demand no longer need to be met from current capacity alone. A pipeline can expand (or extend[11]) capacity.[12] The long run marginal cost (LRMC) of transmitting gas can therefore be thought of as the cost of supplying an increment in demand, allowing for expansions in supply. The LRMC of say, a new compressor, will therefore include all of the additional capital and operating costs that must be incurred to provide the expanded capacity.

26. However, as I noted above, the LRMC of that new compressor *will not* include any of the past, sunk costs of the existing assets, e.g., the existing pipeline and the original compressors. These costs remain the same, regardless of whether the expansion proceeds or not, i.e., they do not vary at the margin. They should therefore have no bearing on the firm's expansion decision. This includes costs that are "common" to both the existing assets and the expansion, as we explain below.

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when its output changes by a specified increment and is often also referred to as incremental cost or avoidable cost (where the specified change involves a reduction in output). For the purposes of this report, we have taken the concepts underpinning marginal, incremental and avoidable cost to be synonymous, since their technical distinctions have no consequences for the matters at hand. For further discussion *see:* Kahn, A, (1988), *The Economics of Regulation, Principles and Institutions, Volume 1* (MIT Press), p.66 (Hereafter: 'Kahn (1988)').

11 An extension involves extending pipeline infrastructure into new geographic locations so as to be able to transport gas along new routes that were previously not able to be served – extensions are also interconnected with an existing pipeline.

12 This may be achieved through "compression" (which enables more gas to flow through the same diameter pipeline) and/or "looping" (which involves adding a pipeline to run in parallel to one or more sections of the existing pipeline, but connected with it).

3.3 Common costs

27. Common costs are costs that must be incurred in order to produce either of two "increments of output" but that do not need to be duplicated when producing the two increments together. Equivalently, common costs are costs that are necessary for the production of the two increments of output but that are only avoided if *both* increments of output cease to be produced. To illustrate, consider our earlier example in which the owner of an existing gas transmission pipeline is considering whether to expand supply.

28. The two relevant "increments of output" in that example are the capacity provided with the existing assets and the additional capacity that will be provided by the expansion. There will be costs that are "common" to both tranches of output. For example, a manager overseeing the functioning of the pipeline might assume responsibility for the expanded capacity as well – but not receive any increase in salary. It may also be neither practical nor possible to attribute his salary in any meaningful way between the two pipelines. It will, for all practical purposes, be "common" to both the existing pipeline and the expanded capacity.[13]

29. More importantly, the costs of the *existing pipeline itself* will also be common across the two increments of output. Specifically, the ongoing operating costs and the past sunk costs that the pipeline owner incurred to construct the existing pipeline are both common with the expanded capacity. This is because, although any customers who use the additional expanded capacity will also be using the pre-existing pipeline:

    - this need have no bearing on the either the ongoing operating costs or the sunk costs of the original pipeline, i.e., those costs do not need to be duplicated; and
    - similarly, if the expansion does not proceed, or if the new capacity is not used, the operating costs and past sunk costs of the original pipeline are not avoided.

30. As I noted above, this mean that those costs that are common to both the existing pipeline and the expanded capacity are not *incremental costs*, i.e., they are not affected by whether or not an expansion proceeds. As I explain in the following section, as a matter of economics, this has significant implications for the way in which those common costs are factored into the prices that a pipeline owner such as GGT sets for its existing capacity and any expanded capacity.

[13] There may be a number of costs such as IT costs, corporate overheads, etc., that fit this description.

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4 Marginal costs and prices

31. In this section, I explain why economic efficiency requires the price for a commodity to reflect the marginal cost of producing it. I then set out the potential implications of this pricing rule for the allocation of the costs that are common to the covered and uncovered portions of the GGP.

4.1 Marginal costs and economic efficiency

32. In his seminal text on the economics of regulation, Professor Alfred Kahn stated that *"the central policy prescription of microeconomics is the equation of price and marginal cost"*.[14] He explains that, because every economy has a fixed bundle of productive resources, the cost to society of producing anything – whether it is gas transmission pipeline capacity or bushels of wheat – consists in other things that must be sacrificed in order to produce it.[15] Professor Kahn explained that it follows that:[16]

> *"If consumers are to make the choices that will yield them the greatest possible satisfaction from society's limited aggregate productive capacity, the prices that they pay for the various goods and services available to them must accurately reflect their respective opportunity costs; only then will buyers be judging; in deciding what to buy and what not, whether the satisfaction they get from the purchase of any particular product is worth the sacrifice of other goods and services that its production entails."*

33. Economic efficiency therefore requires prices to equal *marginal* costs, instead of, for example, average total costs (which would include a share of past sunk costs and common costs). As Professor Kahn explains, this is because:[17]

> *"…the demand for all goods and services is in some degree, at some point, responsive to price. Then, if consumers are to decide intelligently whether to take somewhat more or somewhat less of any particular item, the price they have to pay for it (and the prices of all other goods and services with which they compare it) must reflect the cost of supplying somewhat more or somewhat less – in short* ***marginal*** *opportunity cost."*

34. If buyers are charged more than the true marginal cost for a particular service, they may be inefficiently deterred from consuming it (or consume a less than optimal quantity). This can therefore distort consumption decisions and, potentially, the

14 Kahn (1988), p.65.

15 Kahn (1988), p.66.

16 *Ibid.*

17 *Ibid.*

incentives that businesses have to invest in additional capacity. Professor Kahn explains that this gives rise to the following "rule of thumb" for the businessman: [18]

> *"…it pays him to continue to produce and sell as long as his incremental revenues cover his incremental costs."*

35. This uncontroversial relationship between marginal costs and efficient pricing has significant implications for the way in which the costs that are already sunk and common should be allocated to the covered portions of the GGP and the uncovered expansions. In particular, as I explain below, it suggests that they should be allocated to the pre-existing covered pipeline, since those costs are already sunk and are not *incremental* costs insofar as the uncovered expansions are concerned.

4.2 Application to the GGP

36. I explained above that the marginal costs of uncovered expansions (more specifically, the LRMC) will *not* include any of the past, sunk costs of the covered capacity already *in situ* or the ongoing costs of operating those existing assets, e.g., the existing pipeline and the original compressors. These costs remain the same, regardless of whether an expansion proceeds or not, i.e., they do not vary at the margin. For this reason – and consistent with the reasoning set out by Professor Kahn – they should have no bearing on GGT's expansion decision.

37. If GGT is instead required to allocate a share of the costs of the existing pipeline to the new users of uncovered services, then this will artificially increase the costs of serving those customers because GGT will have to set a price so as to recover incremental costs *plus* the allocation of sunk common costs to the new user.

38. For example, imagine that a new potential mining project was being contemplated that the GGP could serve but which would require GGT to install a new compressor. From GGT's perspective, the marginal costs associated with serving that new customer would be the capital costs and the ongoing operating and maintenance costs of the compressor.

39. Provided that the mining company's willingness to pay (WTP) is greater than those marginal costs, then a mutually beneficial contract can be negotiated, i.e., a price can be struck that GGT will be willing to accept (given the project specific risks involved) and that the miner will be prepared to pay. However, if the mining company is also required to pay for a share of the *existing pipeline*, then this could conceivably prevent that deal from being struck, since:

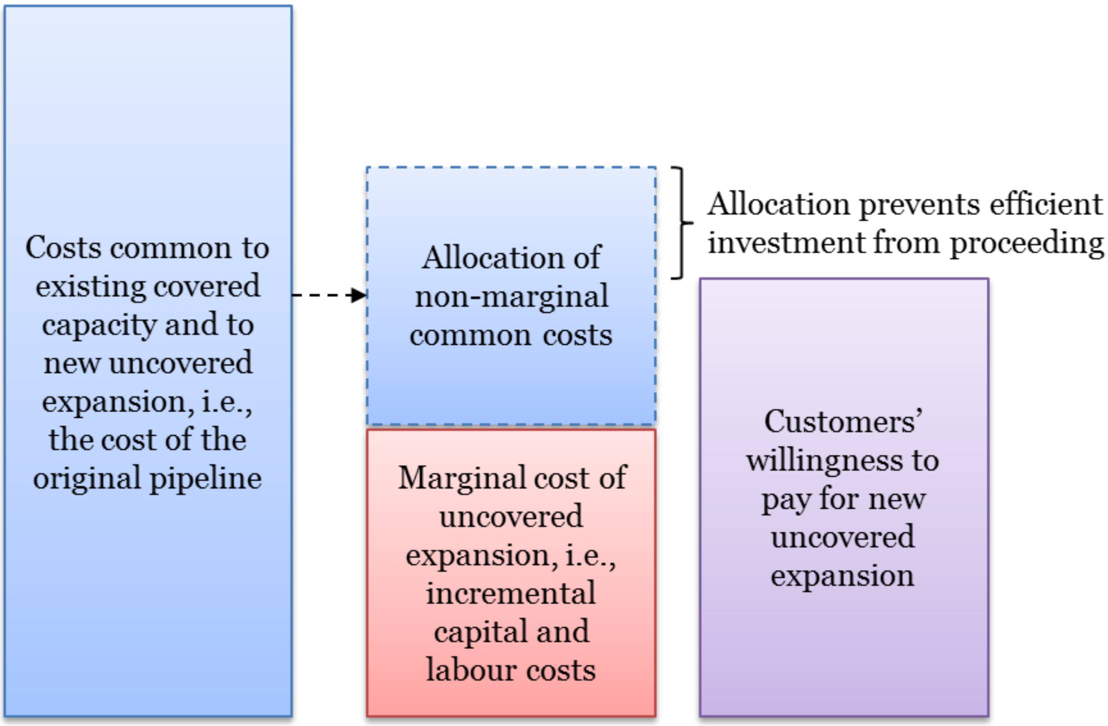
    - from GGT's perspective, it would now need to recover the incremental costs associated with serving the new customer *and* a share of the costs of the existing, sunk asset (the pipeline itself); and

18 Kahn (1988), p.67.

- being forced to also pay for a share of the existing pipeline (a non-marginal sunk cost) might mean that the mining company is no longer willing to proceed with the investment, i.e., the higher price might exceed its WTP.

40. This scenario is depicted in Figure 1. The customer's WTP exceeds the marginal cost of undertaking the expansion, i.e., a contract can be struck that enables GGT to earn incremental revenues that cover its incremental costs. However, once a share of the non-marginal common costs is allocated to the uncovered expansion, that mutually beneficial efficient investment is prevented from proceeding because the amount that GGT must now recover in order to be willing to invest now exceeds the customer's WTP. This is a poor outcome for economic efficiency.

Figure 1 Potential effect of allocation of common costs on investment



41. This relationship is reflected in the theoretically optimal set of arrangements between a pipeline owner and its foundation customers.[19] When the investment in a pipeline is being contemplated, there will be a complex set of negotiations between customers and owners in relation to payment responsibilities, initial capacity rights and rights to future capacity. There is an infinite variety of forms that these rights

19 Note that foundation customers can also be the initial owners in a pipeline. However, the economic analysis I set out below can proceed without loss of generality by referring to distinct groups of "customers" and "owners" – even if some or all of the same entities sit in both categories.

could take.[20] However, consistent with the analysis that I have set out above, the most *efficient* allocation or rights insofar as future uncovered expansions is concerned is that in which:

- the pipeline owner receives the right to a cost allocation rule that allows it the flexibility to charge new users of uncovered expansions the marginal cost of those expansions, i.e., not including any sunk common costs; and
- the customers on foundation contracts forgo future lower prices as the pipeline is expanded to accommodate new users through initial prices that are lower than would otherwise have been the case.

42. This is the allocation implied by the cost allocation rule that GGT is proposing in its access arrangement. In contrast, it will be inefficient to allocate rights in a way that requires the pipeline owner to reduce the prices for the initial foundation customers whenever it serves a new customer by means of an uncovered expansion. The party contemplating taking ownership rights would understand that any such impost would have the following implications:

- the future cost of serving new customers via uncovered expansions will include the implicit payments the owner must make to the initial customers in the form of lower prices, i.e., the costs of expansions will exceed marginal cost; and
- this might mean that uncovered expansions that would have been profitable had the pipeline owner been able to charge new customers a price equal to marginal cost will not proceed.

43. This will reduce the value that a prospective owner will place on those rights and have consequences for the prices it will require from initial customers. Specifically, it will require *higher initial prices* that if no such impost was imposed. Knowing this, the initial customers will prefer that the owner is *not* forced to pay them in the form of lower prices when new customers are served via uncovered expansions.

44. For these reasons, all parties to the initial creation of rights will have an incentive to allocate the rights of ownership such that “payments” to pre-existing customers do not have to be made when uncovered expansions occur. Put simply, the more efficient the initial allocation of rights, risks and rewards, the larger the value created by the investment.

[20] For example, one foundation customer might simply receive rights to X units capacity in exchange for $Y per year with no further rights or responsibilities. Another customer could receive Q units of capacity for $Z upfront together with an ownership right to build, operate and sell any expanded capacity on the pipeline. Another customer could negotiate a clause that requires its annual charges to be reduced by a certain amount in the event new capacity is created on the pipeline etc. Once these rights, responsibilities, risks and rewards are allocated then they, naturally, can be traded to other parties.

4.3 Relevant aspects of the NGL

45. I explained above that GGT's proposed cost allocation methodology ensures that its willingness to supply new uncovered services is based on the incremental costs of those services – undistorted by an allocation of previously incurred sunk common costs. In my opinion, this attribute of GGT's cost allocation methodology is likely to promote the key goals of the NGO. In particular, the ability to serve uncovered expansions at incremental cost will promote the efficient use of and investment in natural gas services, since:

- it will enable GGT to signal the marginal costs of the new investment to the prospective customers;
- efficient investments will not be abandoned simply because of the inclusion of a share of non-marginal sunk common costs; and
- it will avoid the situation in which customers inefficiently reduce their use of the pipeline because of the inclusion of non-marginal sunk costs.

46. In contrast, allocating a share of the costs of the existing covered pipeline – costs which are not marginal – to uncovered expansions may not achieve any of these goals. It may not achieve efficient investment in natural gas services since, as I explained above, it may distort investments in uncovered capacity and in the downstream markets that the infrastructure is used to serve. Specifically, investments may be cancelled, delayed or inefficiently scaled. This would not promote the efficient operation of the pipeline and would not be in the long term interest of consumers.

47. Allocating 100% of the costs of the pipeline proper to customers procuring covered services would also be consistent with the various revenue and pricing principles that sit under the NGO. For example, for the same reasons that I have set out above, GGT's proposed cost allocation methodology would tend to:

- provide it with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services (s.24(2));
- promote economic efficiency with respect to reference services the service provider provides, by (s.24(3)):
  - promoting efficient investment in, or in connection with, the GGP;
  - promoting the efficient provision of pipeline services; and
  - promoting the efficient use of the pipeline;
- have regard to the capital base adopted in the previous full access arrangement decision (s.24(4)); and
- reduce the economic costs and risks of under and over investment by GGT in the GGP and under and over utilisation of the pipeline (ss.24(6) and (7)).

48. In contrast, allocating a share of common costs to uncovered investments is not necessary to achieve consistency with any of these principles. Moreover, for the reasons I set out above, it is likely to be *inconsistent* with a number of these principles – most notably the efficiency principle contained in s.24(3).

5 Conclusion

49. GGT is proposing to determine reference tariffs under its revised access arrangement for the GGP by estimating the total cost of providing pipeline services using only the covered pipeline. One consequence of this is that 100% of the capital costs of the original pipeline (and the initial compressors) are allocated to the covered pipeline and paid for by customers using covered capacity. I have been asked to assess this cost allocation methodology against the economic principles contained in the NGL.

50. In my opinion, the key advantage of GGT's proposed cost allocation methodology is that it enables the prices paid for customers of uncovered expansions to reflect the incremental costs of those investments. This is true both in principle for any future expansions, and I am advised that it has also been the case in practice for past expansions. In my opinion, this is likely to promote the efficient use of and investment in natural gas services, as required by the NGO.

51. By allowing GGT the flexibility to set prices for new uncovered expansions that are based on the marginal costs imposed by prospective customers, the proposed allocation methodology will signal to users the costs that *they themselves* will impose. Efficient investments will not be abandoned simply because those users are forced to pay for a share of non-marginal sunk common costs. It will also avoid the situation in which customers inefficiently reduce their use of the pipeline.