CER
Commission for Energy Regulation
An Coimisiún um Rialáil Fuinnimh

Utility Regulator
ELECTRICITY GAS WATER

SEM Committee

Bidding Code of Practice

Cost Items Consultation

Consultation Paper

SEM-11-026

Index

PART A

PART B

Part A

Risk associated with Movement in Fuel Stock Value

1. Introduction

Following liaison with generator participants, the SEM Committee has identified an issue relating to the treatment of the risk of movement in the value of fuel stocks under the Bidding Code of Practice.

This consultation is intended to seek views in relation to the treatment of the risk as identified below.

2. Key Issues - Replacement Cost Risk

Generator participants who purchase, consume and manage solid and liquid fuels face the possibility that the value of their stock will move over time. The BCOP currently allows generators to make "*reasonable provision for the variability of the prevailing price of a cost-item on a recognised and generally accessible trading market".* This provision allows for a movement in commodity prices between the day ahead price available when generators bid into the SEM and the prevailing price on the trading day.

However, it has been suggested to the SEM Committee that certain solid/liquid fuel plants face very specific risks in relation to managing their fuel stock over the longer term, in particular between bidding into the SEM and the time that the fuel is replaced. This time period can vary depending on the future running regime of the plant in question and on the logistics of replacing stocks.These plants are typically not in the merit order and have no certainty when they will be called to run by the system operator. It has been suggested that the problem for these generators is exacerbated where they are regularly constrained on by the system operator, both of which are inherently uncertain at the time the bid is formulated.

The SEM Committee recognises that this is a complex issue and that generators face many different risks in their day-to-day operations one of which happens to be the risk of movement in fuel prices and the volume of stocks. Hence, consideration needs to be given as to whether the specific risk described above should be allowable in generator's bids.

3. Question for Respondents

Views are welcome in relation to the treatment of the risk identified above, in particular:

1. Should the risk desribed above be considered a short-run risk and be allowable as a cost item in generator's COD? If so, why?
2. If this risk should be considered an allowable cost item then how would you suggest it should be valued?

Part B

Opportunity Cost of Gas Consumption

1. Introduction

The SEM Committee has become aware that generator participant(s) have entered into contractual arrangements to purchase gas sourced indigenously, specifically from the Kinsale Head gas field in the Celtic Sea.

A question has arisen as to the correct interpretation of the opportunity cost of employing the gas procured in this way for the purposes of electricity generation. In addition, the SEM Committee have identified that, in answering this question, it is correct to consider more broadly how best to interpret opportunity cost as it relates to the consumption of gas procured from all sources.

2. Issues

2.1 Historical Treatment

The SEM Committee has historically relied, and continues to rely, heavily on data streams that relate to the spot and day-ahead price of gas on the National Balancing Point (NBP) in Great Britain (GB) as a key reference tool in monitoring for compliance with the BCOP by participants. The NBP has always been considered liquid and generally accessible in the language of the BCOP.

2.2 Indigenous Gas - Background

There are some known differences between gas that is purchased from indigenous sources and gas purchased at NBP, such as:

- Indigenous gas purchased contractually or via the Irish Balancing Point (IBP) cannot be physically re-sold to traders outside the island of Ireland. However the CER is currently working with Ofgem to introduce a back haul product in 2011. There is, however, nothing to preclude owners of indigenous gas carrying out swaps with shippers importing gas from the NBP.

- The IBP is arguably not a recognised and generally accessible trading market as there are a very limited number of active counterparties to trade and there is no published prevailing price index.

- Gas cannot physically flow from the island to Great Britain and this creates the concept of ‘land lock’ of the indigenous gas.

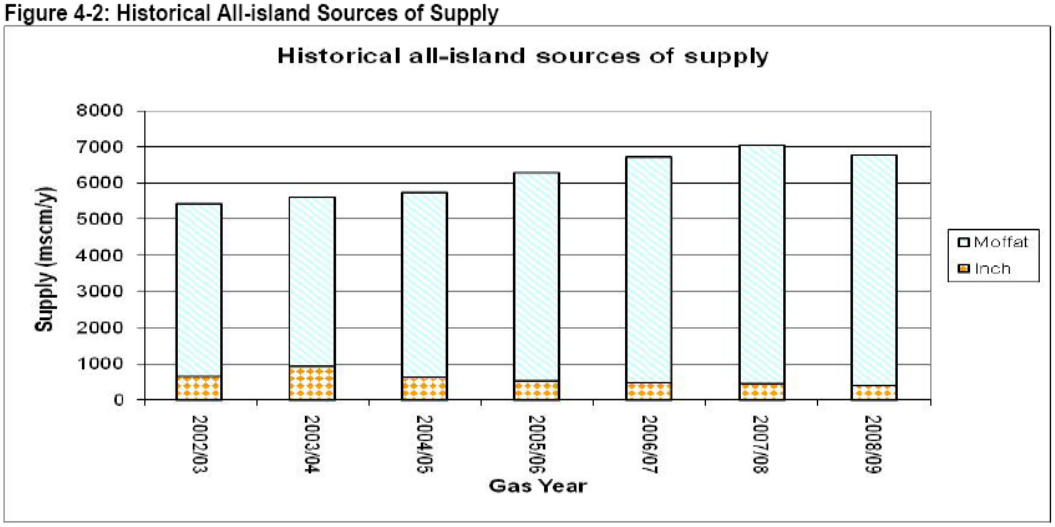
- It has been suggested that most contracts for indigenous gas offtake necessarily feature 'take or pay' arrangements which obligate the purchaser to financially honour all contracted volumes, regardless of whether they are taken.

These effects tend to indicate that, prices aside, indigenous gas may be somewhat more difficult to dispose of for a generator participant in SEM than NBP gas. However, as stated above, given the amount of forward flows of gas on the interconnectors it may be difficult to discount the possibility of executing swaps with gas flowing from NBP.

2.3 Penetration and Developments in Indigenous Gas

The RAs' Joint Gas Capacity Statement (JGCS) 2010 states that interconnector imports of gas "accounted for 94.3% of total Irish annual demand in 2008/09"[1], leaving the contribution of indigenously sourced gas from the Inch Entry point at 5.7% in that year. The JGCS features a graph which shows that this is in fact the culmination of an increasing trend in recent years:

Figure 4-2: Historical All-island Sources of Supply



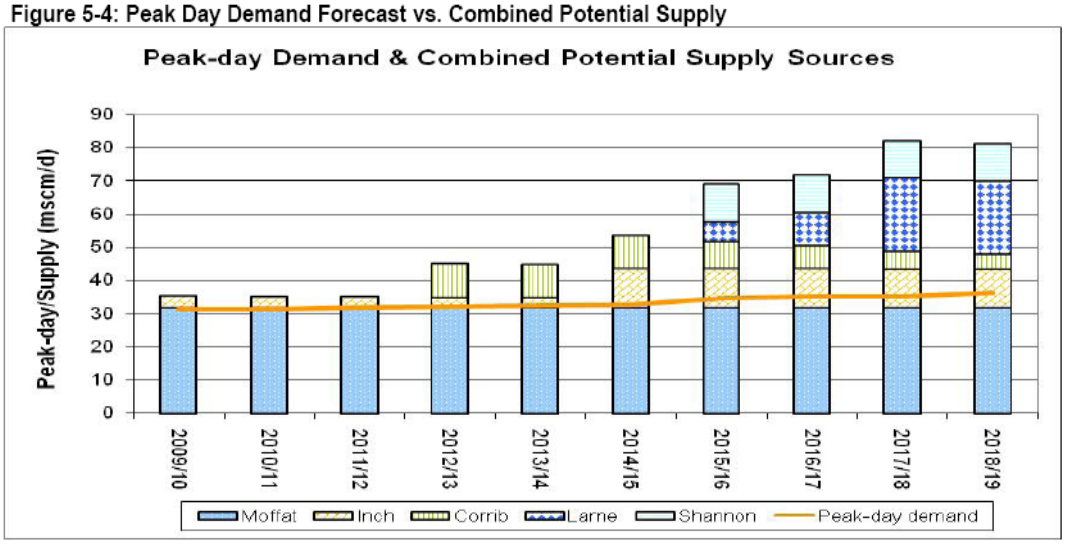
Source: Joint Gas Capacity Statement 2010, CER and Utility Regulator

The graph above shows that the predominant flow of gas has been from NBP sourced imports. This tends to support the SEM Committee position to date, which has been to look to the NBP in establishing the short-run market value and opportunity cost of gas used to generate electricity on the island, at least in the absence of congestion on the interconnectors with GB. Given the relative flows of indigeneous and imported gas it was

[1] This includes NI demand

assumed that all gas for power generation had the same opportunity cost. The data in the JGCS suggests this trend may be set to reverse somewhat with the introduction of a number of projects, including LNG, storage developments and the realisation of the Corrib gas field resource. Such developments could see the further development of the IBP market in the future.

Figure 5-4: Peak Day Demand Forecast vs. Combined Potential Supply



Source: Joint Gas Capacity Statement 2010, CER and Utility Regulator

3. Discussion

The SEM Committee suggests that, so long as:

- there is no physical separation of the apparatus used to procure and transmit the indigenous gas;
- all participants have genuine and unmitigated access to the NBP; and
- all potential trading partners are rational

then (ignoring appetite for risk aversion and normalising for transmission charges) there is economically no difference between choosing to purchase gas from NBP or entering a contract to purchase it from somewhere else. In the context of indigenously sourced gas, if contracting for this exposes a purchaser to extra risks or overheads such as the risk of becoming a distressed seller, it would be expected that the strike price of any contract would factor this effect in, if both the counterparties behave rationally.

The BCOP points to the concept of replacement cost in a situation where there is no generally accessible or recognised market for the cost item. This leads to the question of whether there is a market in IBP gas and whether the IBP market, to the extent that it exists, can fulfil the requirement of being generally accessible, or in a simpler sense, liquid.

It has been contended that, if the behaviour of prices on the IBP is different to the NBP (assuming no flow constraints exist from NBP and normalising other effects like transmission charges), then it is not as recognised and accessible as the NBP. Further, it would be expected that the introduction of increased indigenous volumes (from Corrib and/or elsewhere) and/or the opening of flows from West to East would simply push the IBP behaviour closer to the NBP as traders become increasingly confident that their indigenous purchases carry smaller (or no) encumbrances relative to the alternative of buying from NBP. As such, under these conditions it could be argued that the IBP should be considered liquid only if it behaves the same as the NBP. In either case the result for participants interpreting the BCOP would be to reference the NBP, not IBP.

4. Questions for Respondents

4.1 Accessibility and Recognition of IBP

Should the Irish Balancing Point be recognised as generally accessible and liquid by participants with access to it for the purposes of calculating the opportunity cost of consuming gas?

If the answer to the above question is yes. then what is the IBP price? As there is no published IBP price index then what should be used for bidding and monitoring purposes?

4.2 Opportunity Cost of Gas to participants with Indigenous Access

Given that around 5 to 6% of gas consumed on the island is currently sourced indigenously, should gas-fired generator participants on the island always refer to NBP in formulating their Commercial Offer Data (COD), or should the expectation of the MMU be different to this? Should the MMU expect generators in the SEM with access to indigenous gas sources (via contracts, IBP or otherwise) to refer to some prudent blend of NBP and IBP? How would this change following a significant increase in the volume of gas purchased from indigenous sources (say following commencement of flows from Corrib)?

5. Next Steps

Views are invited on both of these issues and should be submitted to Clive Bowers (cbowers@cer.ie) and Colin Broomfield (colin.broomfield@uregni.gov.uk) by close of business 24th June 2011

Following receipt and consideration of responses, the SEM Committee may issue one or more Clarifications to the Bidding Code of Practice regarding these issues.