Nova Scotia electricity market

Frameworks for
renewable energy contracting and cogeneration contracting

Discussion document.

Robert Cary & Associates Inc, 30th September, 2006.

Contents

1, Introduction

Nova Scotia energy policy is set out in the Government's 2001 energy strategy document "Seizing the Opportunity." In accordance with that strategy, the Electricity Marketplace Governance Committee (EMGC) was established to provide recommendations on implementing the electricity sector strategy. The EMGC reported in 2003, and its recommendations were accepted by the Government of Nova Scotia. Progress has been made to implement these recommendations in a number of areas:

- Nova Scotia Power Inc. has established an open access transmission tariff which is approved by the Utility and Review Board, and which came into effect in 2005.
- The initial set of market rules to address the Nova Scotia wholesale electricity market has been drafted and has been the subject of stakeholder consultation. This initial set of market rules is planned to come into effect on 1st February 2007.
- The Government of Nova Scotia has indicated its plans to introduce a Renewable Portfolio Standard (RPS), and to undertake public consultations on draft RPS regulations in 2006.

The Electricity Marketplace Governance Committee (EMGC) report includes a number of recommendations that are not yet addressed by the above developments. These additional recommendations include those regarding renewable and cogeneration sales to retail consumers, and regarding the development of top-up and spill rates and backup rates to complement the operation of independent generating facilities. This discussion document addresses issue to be addressed in implementing these market-oriented recommendations (41, 51, 52, 63, 64, 65, 75 & 76).

Readers are also referred to the companion discussion document on green attribute administration in Nova Scotia, which addresses the EMGC recommendations relating to that issue (41, 42, 43, 44, 45, 49 & 50), taking account of the various broader policy developments in the area of greenhouse gas emissions.

The EMGC report also included certain recommendations relating to purchase of cogeneration output by NSPI under long term power purchase agreements (PPAs), and relating to the purchase of cogeneration output by distribution utilities. Such PPAs are not part of the "market" framework, and these recommendations (66, 67 & 68) are therefore not addressed in the present discussion document.

The Government of Nova Scotia has indicated its intent to initiate discussion of the electricity market developments that would address outstanding market-oriented issues with respect to renewable energy contracting and possibly with respect to cogeneration contracting. This document is therefore prepared as a basis for discussion of these issues in preparation for any development of rules or regulations on these outstanding issues. Policy options remain open at this time, and any proposals contained in this document are those of the consultant and have not in any sense been adopted by the Government of Nova Scotia.

2, Structure of this document

The first part of this discussion document identifies several ways for buyers and sellers to arrange their contracts, and identifies the issues that need to be addressed at the institutional level to enable such arrangements. Four "contractual arrangement" options have been identified. Two options are for "financial contracts" and two are for "physical contracts" as described within the relevant sections. In order to support the safe, reliable and economic supply of electricity to Nova Scotia consumers, the design of the electricity market should seek to enable maximum flexibility in such arrangements and to facilitate competition in ways that do not harm other parties.

In reviewing the contractual arrangement options, it becomes evident that there are two closely related core issues that are common to multiple options. If the contractual arrangements between the parties are essentially financial, the issue is the pricing of the "null energy" sale to NSPI. If the contractual arrangements between the parties are essentially physical, the issue is the pricing of so called "top-up and spill" energy purchase and sale arrangement with NSPI. These pricing issues are closely linked and are discussed in parallel through most of this document.

Pricing issues are then discussed in the particular context of each contractual arrangement option.

Other issues are discussed in a separate section.

The document than identifies for discussion a proposed resolution of each issue.

In order to facilitate a focussed discussion this document then identifies a set of suggested discussion topics. These are not intended to be exclusive.

In order to describe the options and issues in a concise manner it is necessary to use certain terms that may not be in general use. These terms are included in the glossary, appendix C of the green attributes discussion document. Also in order to provide clarity, it is useful in some instances to use quantitative and monetary examples. The numbers used in such examples are selected with a view to reasonable illustration, but are not in any sense definitive.

3, Contractual arrangement options

Contractual arrangements between generators and buyers may be either physical or financial, and may relate to either electricity, attributes, or both.

Under a physical electricity contract the electricity is supplied from the generator to the load under their bilateral contract, and is transmitted from the generator to the load under the terms of transmission tariff. Under a physical attribute contract, the attributes are linked to the electricity that is the subject of the physical electricity contract.

In a financial electricity contract the physical delivery of electricity is not impacted by the parties' bilateral contract. A financial electricity contract would be an agreement whereby the buyer would pay (or be paid by) the seller the difference between the regulated price and the predetermined contract price, to give the buyer a predetermined total cost.

Under a financial attribute contract, the attributes are transferred to the buyer at a predetermined price, potentially independent of any electricity sale.

When considering both electricity and attributes, these arrangements may be combined in a number of ways:

Electricity contract	***Attribute contract***		
	Physical	***Financial***	***None***
Physical	**A** Attributes linked to electricity in bilateral sales or NSPI PPAs. Options A 1 & A 2 represent different "balance of supply" arrangements.	**B** Null energy sale to NSPI or other buyer, and separate attribute sale, which may be under a common contract or may be among different parties. Options B 1 & B 2 represent different "balance of supply" arrangements.	**(B)** Electricity sale only, including any null energy sale to NSPI.
Financial	n/a There can be no physical attribute contract without a physical electricity contract	**C** Electricity price hedge (implies separate null energy sale to NSPI) and potentially separate attribute sale.	**(C)** Electricity price hedge only (implies separate null energy sale to NSPI).
None	n/a For reason as above.	**D** Attribute sale only (implies separate null energy sale to NSPI).	n/a This is the default regulated supply arrangement.

At this stage there are four contractual arrangements identified (A, B, C & D in the above table) for review. One of these (A) is a purely physical arrangement in which attributes cannot be separated from electricity, and the other three (B, C & D) depend on at least some financial contracting. Arrangements A & B provide for physical electricity contracts, and are subdivided to reflect alternative arrangements for any balance of supply by NSPI.

Arrangements B, C & D all provide for the separation of attributes from electricity, and permit the trading of such attributes quite independent of the energy. Arrangement A does not permit such separation, and requires linkage to be maintained. This difference can have significant implications from a policy perspective. These are discussed in the discussion document on Green Attributes administration.

At times when generation output is insufficient to meet the buyers load, the shortfall could be made up in either of two ways, representing the two options under alternatives A and B: bundled service for the residual part of the load; or fully unbundled service including an unbundled "top-up" generation service from NSPI.

These four arrangements and two additional options are described in more detail in the following paragraphs.

A, Physical electricity contract, with linked attributes, option A1: partially unbundled service

- Potential scope:
  - Generation: renewables and cogeneration
  - Load: wholesale and transmission-connected retail
  - Also for other generation supplying wholesale load.
- Characteristics:
  - Generator sells scheduled quantity to load as primary supply at pre-determined contract price (ie electricity price hedged by generator).
  - Attributes included with electricity sale (ie attribute price included with electricity price).
  - Generator sells scheduled surplus to NSPI as null spill, null energy or renewable spill / energy.
  - Load purchases transmission service under the transmission tariff, based on the unbundled portion as scheduled (network service).
  - Any variation from schedule is tariff imbalance:
    - load imbalance if primary schedule exceeds total actual;
    - otherwise generator responsibility for imbalance.
  - Load purchases balance of supply as bundled service.

- Related issues:
  - Pricing treatment of energy scheduled as surplus output ("null" or "spill").
  - Treatment of attributes associated with such energy.
  - Duplication of transmission network service charge included in bundled rate.
  - Policy issue on the availability of null energy pricing for "other generation" that has no environmental policy support.

A, Physical electricity contract, with linked attributes, option A2: fully unbundled service

- Potential scope:

  As option A1

- Characteristics:

  As option A1 except
  - If generator is not available for scheduling for full load, then load purchases back-up or "top-up" energy from NSPI.

- Related issues:
  - Pricing treatment of energy scheduled as surplus output ("null" or "spill").
  - Treatment of attributes associated with such energy – may be part of load purchase to cover 100% of energy requirements.
  - Development of backup or "top-up" pricing and "spill" pricing.

B, Physical electricity contract, separate attributes, option B1: partially unbundled service

- Potential scope:
  - Generation: renewables and cogeneration
  - Load: wholesale and transmission-connected retail
  - Also for other generation supplying wholesale load.

- Characteristics
  - Generator sells scheduled quantity to load as primary supply at pre-determined contract price (ie electricity price hedged by generator).
  - Generator sells corresponding attributes to load at pre-determined contract price (ie attribute price hedged by generator).
  - Generator sells scheduled surplus to NSPI as null spill, null energy or renewable spill / energy.
  - Load purchases transmission service under the transmission tariff, based on the unbundled portion as scheduled (network service).

- Any variation from schedule is tariff imbalance:
  - load imbalance if primary schedule exceeds total actual;
  - otherwise generator responsibility for imbalance
- Load purchases balance of supply as bundled service.

➢ Related issues:
- Pricing treatment of energy scheduled as surplus output ("null" or "spill").
- Treatment of attributes associated with such energy.
- Duplication of transmission network service charge included in bundled rate.
- Policy issue on the availability of null energy pricing for "other generation" that has no environmental policy support.

B, Physical electricity contract, separate attributes, option B2: fully unbundled service

➢ Potential scope:

As option B1.

➢ Characteristics:

As option B1 except:
- If generator is not available for scheduling for full load, then load purchases back-up or "top-up" energy from NSPI.

➢ Related issues:
- Pricing treatment of energy scheduled as surplus output ("null" or "spill").
- Treatment of attributes associated with such energy – may be part of load purchase to cover 100% of energy requirements.
- Development of back-up and "top-up" pricing and "spill" pricing.

C, Financial contract with electricity price hedging

➢ Potential scope:
- Generation : renewables and cogeneration
- Load: wholesale and retail
- Also for other generation supplying wholesale load.

➢ Characteristics
- Generally the same as for "D, attributes only" except:
  - generator provides hedge of total energy cost to buyer;
  - this requires addition of a linkage between the null energy price and the bundled price, so that this spread is predictable to the generator;

- this has the consequence that NSPI carries some risk (up and down) that this spread would in fact vary in some unexpected way.

- Related issues:
  - How to create such a linkage, and the impact on others.
  - Policy issue on the availability of null energy pricing for "other generation" that has no environmental policy support.

D, Financial contract for attributes only

- Potential scope
  - Generation : renewables only (due to limited attribute value of others)
  - Load: wholesale & retail.

- Characteristics:
  - Generator sells null energy to NSPI at null energy price (generator may carry exposure to the variation in the null energy price).
  - Load purchases bundled supply from NSPI (load carries the exposure to changes in the bundled price including the RPS compliance element).
  - Load purchases attributes from generator at predetermined attribute price (ie the attribute price is hedged).

- Related issues:
  - Determination of the null energy price.
  - Possible use of "RPS-neutral" energy instead of truly null energy.
  - Interaction with renewable attribute tracking & trading – see separate discussion document on green attribute administration.

4, Energy Pricing Principles

Within the characteristics and related issues set out above for the four contract arrangements, there are potentially five rate / price requirements to supplement the existing bundled service pricing:

- null energy purchase (by NSPI) price;
- spill purchase price - null energy;
- spill purchase price - renewable energy;
- back-up sale price – RPS compliant energy mix;
- top-up sale price - RPS compliant energy mix.

Many of the price determination principles are common to all of these five prices. These principles are therefore identified in general terms. The following principles are proposed as a basis for determination of any of the five prices.

- Must hold NSPI harmless with respect to the cost of fulfilling its obligations:
  - NSPI purchases must not over the medium / long term exceed the cost of alternate sources.
  - NSPI purchases should reflect NSPI avoided net total costs:
    - energy;
    - capacity – if committed, then offsets other capacity needs;
    - ancillary services – if additional or incremental ancillary services are required to offset intermittent generation impacts;
    - required green attributes – if incremental costs are triggered;
    - recognising location-specific impacts.
- Neither NSPI purchases nor NSPI sales should provide economic incentives in conflict with the object of the market.
- Should be simple to administer
  - eg leveraged off existing processes.
- Should be transparent.
- Should be fair, including with respect to those not eligible for any particular class of purchase or sale.
- Preferably should be capable of application to:
  - intermittent (non-controllable); and
  - cogeneration (controllable);

  with appropriate treatment of capacity and ancillary service elements for each case.
- Should have due regard to the level of certainty required to support investment – how will price vary over time, and who carries what risks in that regard ?

5, Pricing options and issues

Certain price determination options are common to all the five prices. These options address issues of:

- marginal energy cost basis or average energy cost basis;
- energy pricing timelines;
- relationship between marginal energy price and bundled price;.
- relationship with transmission tariff imbalance charges;
- cost of capacity;
- ancillary services – if additional or incremental ancillary services are required to offset intermittent generation impacts;
- required renewable attributes – if incremental costs are triggered;
- recognising location-specific impacts;
- long term price cap on NSPI null energy purchases; and
- treatment of embedded generation.

Each is therefore discussed in general terms before specific application.

5.1, Marginal energy cost basis or average energy cost basis

EMGC recommendations with respect to backup rates and top-up and spill rates both refer to "cost based" and "regulated / approved by the UARB". Such a description would admit rates based either on marginal cost or on average cost. Such a description also admits pricing that is predetermined at a fixed value(s) such as the normal large and small customer rates, and pricing that will vary according to some predetermined principle such as the 2-part RTP rates. It is recognised that the EMGC recommendation only requires that these rates be based on cost, not that they necessarily equal cost.

The marginal cost of energy represents the saving that NSPI would make by reducing its own generator output or procurement of energy from other sources. It is typically, but subject to certain qualifications, the cost of the most expensive energy being used at any time. An indicative pricing level for this is 6.5 cents / kWh[1].

The average cost (or embedded cost) of energy is the basis of NSPI's bundled rates. It is the average of all sources. Absent any inclusion of allocated fixed costs, it is almost without exception less than the marginal cost. An indicative pricing level for this is 4.0 cents / kWh[2], exclusive of fixed costs.

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[1] NSPI compliance filing, April 2006, rate code 98 adjusted to exclude additional cost items and transmission losses (ie priced at the generator bus).

[2] NSPI compliance filing, April 2006, appendix 2, table 8 indicates total fuel cost of 3.323 cents / kWh; appendix 3, exhibits 4 & 5 indicate variable energy costs in the order of 4.0 cents / kWh and

It is suggested that marginal cost is on first examination the most appropriate basis for all NSPI energy purchases, as any such purchase would yield a marginal cost saving to NSPI. There are however arguments for developing a proxy for such marginal costs, with a direct linkage to the average cost; this is discussed below under the heading "relationship between marginal energy price and bundled price".

All NSPI sales at bundled rates include energy on an average cost basis, as is appropriate for all sales under NSPI's obligation to serve Nova Scotia consumers.

Other NSPI sales may be designated as non-obligated sales (eg interruptible customers and export transactions) for which a marginal cost basis is the most appropriate.

It will be necessary to review the various linkages among the different price classes in order to arrive at consistent and compatible rate structures.

5.2, Energy pricing timelines

Energy pricing could be determined, amongst other options:

- annually in advance,
  - annual or seasonal prices with on/off peak separation;
- daily in advance,
  - daily prices with on/off peak separation, or
  - hourly prices;
- retrospectively,
  - daily prices with on/off peak separation, or
  - hourly prices.

NSPI presently determines prices using two of these timelines: the bundled rates are set annually (or less frequently) in advance, recognising seasonal(?) and on/off peak separation; Time of Use rates (code 36) are determined for each hour of each dispatch day, and are finalised at least 20 minutes ahead of the applicable hour. While other options could be considered, these two options seem to be reasonable representative of the range, and offer the benefit of leverage off existing processes. Consideration should be given to day-ahead determination of hourly marginal prices as an alternative to hour-at-a-time determination.

On balance, the use of day-ahead determination of hourly price appears to be provide a reasonable balance for the determination of marginal prices.

- It minimises the risk to NSPI of incremental costs, and holds other parties harmless.
- It minimises incentives for behaviour inconsistent with the object of the market.

fixed energy costs in the order of 1.6 cents / kWh. This is compatible with the 5.1 c/kWh ELIIR rate at 100% load factor.

- It exposes independent generators to greater short term variability; but any regulatory rate setting would be expected in any case to reflect the long term actual cost, so the impact is more on timing and dynamics than on overall outcome.
- Transparency of price setting would need to be addressed, as it is not part of present market processes.
- Publication of hourly marginal prices goes beyond present market rules, but is consistent with other electricity markets. Timing needs to be considered. Impacts on NSPI trading need to be considered.

5.3, Relationship between energy marginal price and bundled energy price

5.3.1, What does the price difference represent?

As noted above, the average marginal cost is ~6.5 c/kWh, while the average total production cost is ~4.0 c/kWh. This difference arises principally from the inclusion in the average of the lower cost facilities that would be dispatched first.

5.3.2, Implications of this relationship

The numbers indicated above are based on projections. In the short term the hourly marginal energy price will vary significantly, and independently of the bundled price. In the longer term the annual average marginal price would be expected to show much less volatility, but may still change over time relative to the average cost. While there will be a degree of implicit linkage, this will not automatically be absolute.

If a generator is to use a financial electricity contract to provide a long term electricity price hedge to a load, the lack of firm relationship could be problematic. The generator's total revenue would be

> null energy payment from NSPI (= marginal energy price) + contract payment from load (= contract price – bundled energy price).

This can also be expressed as

> (marginal energy price – bundled energy price) + contract price

which shows the generator's exposure to the relative variation – the "relative price risk"..

5.3.3, Relative price and the relative price risk

The use of marginal energy price for null energy purchases and bundled price for sales can be seen as a benefit in view of the price difference, or could be seen as an obstacle to any party seeking to use a financial electricity contract arrangement as the means to achieve an energy price hedge (ie to lock in a long term net electricity cost for a load). It is necessary to identify the extent to which the relative price risk might outweigh the benefits of the relative prices and limit trade and realisation of policy.

All eligible transmission customers would have choice between physical electricity contracting and financial electricity contracting; this would allow the implementation of EMGC recommendation 63, and the physical contracting portion of recommendation 65. If it is expected that the relative price risk would outweigh the benefit of the relative pricing itself, then physical electricity contracting becomes important. In that case the widest range of transmission connected customers should probably be made eligible as transmission customers and market participants in respect of output from renewable generators or co-generators. If not, then the lack of ability for physical electricity contracts does not inhibit trade or investment.

5.3.4, Potential creation of linkage

If the relative price risk is seen as materially limiting trade, there are two solutions. The first is to permit physical contracting as discussed in the preceding paragraph. The second it to create an artificial linkage between the marginal price and the average price. In that case the marginal price would cease to be a true marginal price, and would merely become a proxy for the marginal price. The disadvantage of this is that the marginal price immediately departs from the principles set out in section 4; neither NSPI not other consumers are necessarily held harmless. Any modification that does hold those parties harmless breaks the linkage.

5.3.5, Conclusion

Given:

- the regulatory transparency of the price setting;
- the customer base for which this could become a material obstacle to fixed electricity pricing; and
- the possible implementation of wider transmission tariff eligibility to include all transmission-connected customers in respect of renewable[3] and potentially co-generated electricity;

the argument for creating an artificial linkage between the null & spill pricing and the average pricing is not strong. It is overwhelmed by the arguments for using actual marginal costs as the basis of pricing of the null & spill purchases by NSPI.

5.4, Cost of capacity

5.4.1, General

Capacity costs are long term costs which are not included in energy costs.

The demand-charge element of bundled rates includes elements of the generation capacity cost as well as the transmission-related capacity cost.

[3] See also discussion in Nova Scotia electricity market, Green attribute administration discussion document, 30th September, 2006.

Any applicable capacity costs should therefore be represented by separate price elements in each of the null energy, spill, back-up and top-up prices.

5.4.2, Capacity purchase by NSPI

NSPI may, as a result of expected long term null energy purchases, experience savings in other capacity investments. This saving would be the same as if the resources had been under contract to NSPI.

The capacity MW value of wind generation resources (ie the saving in other capacity investments) is typically set between 10% of the installed capacity and the average output (eg 35% of the installed capacity) depending on the degree of correlation (positive or negative) between system load and wind generation output.

The capacity price should theoretically relate to the marginal cost of alternative capacity. There are however a number of problems in arriving at any definitive determination of marginal capacity cost. Capacity decisions are made infrequently (not hourly as for energy). Capacity investment is lumpy, to achieve economies of scale. Capacity type (and therefore capacity cost) is determined in association with energy costs (ie the type of investment that would be undertaken, and thus its fixed capacity cost depends on the energy needs as well as the capacity needs). It is much harder to pinpoint a marginal capacity cost than to pinpoint the marginal energy cost. Three approaches can be immediately contemplated (not to preclude others). The price payable for capacity could be taken from the embedded capacity cost used for the determination of operating reserve rates in the transmission tariff[4]. The price payable for capacity could be taken from the generation embedded capacity cost included in the bundled rates[5]. Or the price could be taken from the cost of a hypothetical new gas turbine generator[6]. Given this range and the detailed analysis required to arrive at a definitive rate, a rate of $ 9 / kW / month will be used later in this report for illustration.

Given the lumpy nature of most generation investment, there are years in which Nova Scotia generation resources may exceed those required to preserve necessary reserve margins. Unless it becomes evident from the NSPSO's forecasts and assessments

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[4] NSPI transmission tariff evidence, exhibit 4, revised May 2005, indicates the wide range of embedded capacity costs between generating stations. As a simplified indicator, use the simple average of the values determined in the final cell of tables 4-5 ($ 94.63/ kW yr), 4-6 (52.49) & 4-7 (100.66). This simple average is $ 82.6 / kW yr or $ 6.9 / kW / month.

[5] NSPI compliance filing, April 2006, appendix 3, exhibit 5 indicates $ 116 million demand-related production cost. This is adjusted to $ 229 million to take account of the initial allocation of rate base (appendix 3, exhibit 2A of compliance filing) as opposed to the fully classified allocation of rate base (appendix 3, exhibit 2B of compliance filing) as appropriate for this purpose. NSPI website indicates installed capacity of 2,293 MW, implying a demand-related production cost of $ 8.3 / kW / month.

[6] New GT capacity costs which would typically exceed $ 10 / kW month.

that generation is in long term surplus, it can reasonably be assumed that independent generation investment will displace or defer NSPI generation investment or contracted investment. It should therefore qualify for capacity payment based on the MW quantity determined as indicated above, and at the average rate also indicated. The exception would be if, as a result of such long term surplus, the NSPSO has determined that new generation supply does not create other capacity savings and has given notice to that effect, then new generation committed after that notice should not qualify.

5.4.3, Capacity sales by NSPI

Back-up sales are assumed to be always firm. Top-up sales can be contemplated on a firm basis or a non-firm basis.

Firm back-up and top-up sales imply capacity reservation to meet any top-up energy requirements. The amount of required capacity reservation is easiest indicated by examples for cogeneration and wind generation respectively.

- Consider a 100 MW firm load.
- This load is served by a 100 MW cogeneration plant (and ignoring for now any load served directly from that plant).
- Total system adequacy requires that there be a total of 120 MW capacity (after discounting for intermittent capability etc) on the system to support the firm load.
- 100 MW of this is provided by the cogeneration plant.
- 8 MW (say) of this is paid for by the load through the ancillary services charges under the transmission tariff.
- The balance, 12 MW must be paid by the load as a capacity payment to provide firmness to the top-up payment. This is effectively a reservation fee, payable every month. This 12% number is used for later illustration purposes.
- The rate per MW would be the same as is used for NSPI capacity purchases.

Consider the same 100 MW load served by a 200 MW wind farm with an evaluated capacity value of say 30%. In this case, the load still requires the support of 120 MW capacity, of which 200 MW x 30% = 60 MW is provided by the wind farm. 8 MW continues to be paid by the load through the ancillary services charges. In this case the balance to be paid by the load as a capacity payment to provide firmness is 52 MW (= 120 – 60 – 8).

Non-firm top-up sales would not require any capacity payment.

5.5, Ancillary services – if additional or incremental ancillary services are required to offset intermittent generation impacts

Intermittent generating facilities require to be complemented by dispatchable generating facilities. These dispatchable generating facilities must be capable of compensating for the deviation of actual from forecast intermittent facility output. As long as intermittent

facilities are a small proportion of the generation fleet, this burden on dispatchable facilities is likely to be small relative to load variability; it is also likely to be small relative to the existing requirements for load following and for operating and supplemental reserves. Beyond a certain point, additional intermittent generation is likely to require that the system carry additional load-following or operating reserve resources. This is dependent on physics, not ownership or control, and so is equally applicable for NSPI owned resources, NSPI PPA resources and for independent resources.

It is not known precisely at what point such requirements would become applicable. This would require to be established on the basis of study drawing on growing Nova Scotia experience as well as experience elsewhere.

Once such requirements do become applicable, they take the form of a capacity charge, offsetting any capacity credit established in accordance with section 5.4. Either:

a) this cost could be shared between and applicable to all intermittent generation (but absorbed by NSPI for its owned and PPA resources); or

b) the cost could be attributed only to incremental intermittent generation added to the system after the point that triggers the need.

Given the difficulty and potential inequity of (b) it is suggested that (a) be adopted if and when it becomes necessary to recognise such impacts.

Given also that not all renewable generation is necessarily intermittent, this could result in different pricing for null energy from intermittent and controllable renewable generation. This difference can probably best be accommodated by variations in the capacity amount, which may in any case be somewhat facility-specific due to differences in the capacity value % at different sites.

5.6, Required renewable attributes – if incremental costs are triggered

If a null energy purchase facilitates the export of the renewable attributes (or any part thereof) such that it increases the cost to NSPI or the Nova Scotia consumer pool of policy compliance, how should this be reflected?

This could arise if the most economical renewable resources are developed for null energy sale to NSPI and export sale of attributes, leaving NSPI or other LSEs to pay the higher price of developing less economical resources to fulfill Nova Scotia policy objectives. The more economic resource would thus be used to serve an export market, and the incremental benefit of the more economic resource would accrue to the developer and not to Nova Scotia consumers through lower policy compliance costs.

In order that the export value of attributes, or of a component of them such as carbon reduction credits, be higher than the Nova Scotia value of renewable attributes, they would likely need to represent an excess over the RPS requirement. If Nova Scotia policy objectives can be fulfilled through an RPS that leaves such an excess, then export is

probably an appropriate way to capture the economic benefit of additional generation development in the province. If the RPS is set at a level that captures substantially all the available resource, then the excess would not exist or be available for export.

This issue is discussed in greater depth in the discussion document on green attribute administration. If addressed appropriately in that context, there should be no need to introduce specific measures to recapture from one developer the incremental costs of the next increment of development.

5.7, Recognising location-specific impacts

Location-specific impacts would be recognised firstly through measures identified in the process of system impact assessment, including in particular any special locational loss factor identified in paragraph 2.2.6.4 of the draft electricity market rules.

5.8, Long term price cap on NSPI null energy purchases

It could be argued that the total price available to generators through null energy sales should not over the long term exceed the prices payable by NSPI under its PPAs. It would be argued that PPA purchases would represent the avoided costs arising from the null energy purchases by NSPI.

On the other hand, if NSPI expects such an outcome, its prudent course would be to contract for additional supply at such prices until the long term average marginal cost would be thus reduced. If NSPI has decided otherwise, then other generators should not suffer from capping of prices at that “what it would have been” level, particularly as the numbers are likely to vary from year to year, and this would impose an asymmetrical risk.

On balance therefore, there is no case for capping prices for null energy purchases by NSPI.

5.9, Treatment of embedded generation

Embedded generation is used here to refer to any case where generation and load are located behind the same NSPI (transmission or distribution) delivery point or are aggregated to achieve like effect, and where the generation provides supply to the load.

Present tariff provisions and regulations would normally provide for the generation and load to be netted off in any hour, and the party to settle with NSPI for that net amount, but without physical offset between hours. It is possible that generator output in excess of the peak gross demand may qualify for different treatment than the generation that is potentially used for load displacement. This needs further examination.

As an alternative, it may be open for the generator to request separate metering from the load, so that the whole of its output qualify for (say) null energy pricing, and the gross load

be provided with bundled service. This needs to be examined in more depth to determine if it would represent behaviour harmful to others or in conflict with the object of the market.

6, Analysis of each price requirement

For each of the five price requirements, it is then necessary to consider its need and applicability, which may lead to the prescription of terms. Then we must consider the determination of each required price; this will be based on application of the identified principles and of the particular issues identified in the previous section. The weight given to conflicting principles will likely depend on the application context. Note that, while back-up and top-up pricing have been separately identified within the list of five price requirements, the applicable issues are shared. They are therefore considered jointly in this section. The only distinction would be with respect to the exclusion of the capacity element from non-firm top-up pricing.

6.1, Null energy purchase (by NSPI) price

- Need and applicability:
  - Not a concept explicitly defined by EMGC.
  - Given the dominant position of NSPI in the Nova Scotia electricity market, it is needed to allow meaningful implementation of separate trading in RPS tags in accordance with EMGC recommendation 41.
  - Available :
    - to any renewable generator in respect of 100% of its output;
    - to any embedded renewable generator in respect of output in excess of (annual?) peak gross load demand;
    - to any renewable generator in respect of output in excess of highest contracted bilateral demand;
    - could be made available to cogen on a similar basis.
- Price determination:
  - Null energy price – base proposal in respect of scheduled output;
    - Marginal energy cost for each hour as determined in the day ahead (illustrative amount 6.5 c / kWh annual average).
    - Capacity price paid for effective capacity of resource, taking account of reliability and intermittent operating factor; illustrative amount 25% factor x $ 9 / MW of installed capacity.
  - Tariff imbalance charges to renewables within +/- 2 MW bandwidth are on the same basis for energy, and so introduce no distortion. Tariff imbalance charges beyond this bandwidth or for non-renewables impose 10% energy price penalty.

6.2, Spill purchase (by NSPI) price for null energy

- Need and applicability:
  - Identified by EMGC as regulated rate in conjunction with top-up.

- Price determination:
  - Similar to null energy price determination except that there are different capacity considerations:
    - Spill pricing has no capacity element as spill is assumed only available off-peak (guaranteed excess capacity may warrant different treatment – eg as null energy).
  - Also similar to tariff imbalance with prior scheduling.
  - Same marginal cost basis as for null energy and tariff imbalance within permitted bandwidth is appropriate.

6.3, Spill purchase (by NSPI) price for renewable energy

Renewable generation can be linked with top-up and spill service to meet the electricity requirements of load. In a strictly physical system of attribute trading (arrangement A), the electricity and its attributes are all accounted on an hourly basis, and the spill would pass to NSPI with all its attributes; the top-up would be either null or RPS-compliant energy. This would make it difficult for a load to procure 100% green energy, and would result in the transfer of all spill attributes to NSPI. In that circumstance, it could be appropriate to recognise the attribute value in enhanced spill pricing.

The issue can be resolved under arrangement A if the attribute accounting is done on a monthly or annual basis.

If separate financial contracting is permitted for attributes under arrangement B, C or D, then this is not an issue.

A separate renewable spill price is therefore not considered.

6.4, Back-up and top-up sale (by NSPI) prices

- Need and applicability:
  - Back-up was identified by EMGC as a regulated rate.
  - Top-up was identified by EMGC as regulated rate in conjunction with spill.
  - While it would be possible to create a distinction between these two rates (eg on the basis of the primary generation source; the period of notice of requirement; or the pairing with spill) they are largely synonymous, and they are treated as such with respect to price determination.
- Price determination:
  - The energy component can be considered as paired with spill to produce something equivalent to net billing when the two have the appropriate temporal relationship:
    - Implies marginal cost basis (illustrative 6.5 cents / kWh).

  - Preferred basis for consistency with spill and tariff imbalance.
- Back-up and top-up could also be equated to the bundled service net of the transmission and ancillary services which would all be paid under the transmission tariff:
  - Would imply average cost basis.
  - This would result in lower energy price (illustrative 4.4 cents / kWh).
  - Not favoured as it would create split between top-up rate and spill rate.
- Back-up and top-up pricing do have a capacity element corresponding only to the capacity reserve portion of the bundled service cost, not the full capacity cost:
  - Determined by the fact that the back-up or top-up requirement adds to NSPI's capacity requirement. This will typically be factored on either the un-reliability or the un-availability of the generation in question, and should be in the form of a fixed reservation payment.
  - Illustrative pricing capacity 12% of $ 9 / MW month for a cogen facility or 52% of $ 9 / month for the wind farm example in section 5.4.
- Top-up pricing could be offered on a non-firm basis without a capacity charge.
- Back-up and top-up pricing as suggested at marginal cost plus capacity reservation cost could result in higher charge than the bundled service charge for partially unbundled service. This could provide an incentive to stay with partially unbundled service, as opposed to a back-up or top-up and spill arrangement. See discussion in section 7.3 below.

7, Other issues

7.1, Interaction with attribute tracking & trading

Issues discussed in the discussion document on Green Attribute administration.

7.2, Duplication of transmission network service charge included in bundled rate (partially unbundled service issue only).

This is a relatively minor issue that could be corrected by a tariff amendment.

7.3, Comparison between back-up or top-up service and bundled service (under partially unbundled service)

Back-up or top-up service and bundled service provide alternative arrangements for the assurance of supply. For renewable generation which is typically intermittent and non-controllable this choice of options seems appropriate.

For controllable generation, the options need to be evaluated using more definitive pricing data in order to identify if either of them offers any inappropriate incentives for generation patterns that would be in conflict with the object of the market. If analysis does identify any inappropriate incentive structure, then it may be necessary to limit choice for non-renewable generators.

7.4, Scale issues and stranded assets

The above discussion is premised on the assumption that the level of independent generation investment would contribute to addressing demand growth or RPS requirements, and would not "strand" existing NSPI capacity as being unnecessary for reliability or RPS and uneconomic for energy.

The issue of any exit fees for parties using physical electricity contracts (arrangements A and B) which may "strand" NSPI generation assets was addressed by EMGC in its recommendations 77 to 81.

Under financial electricity contracts (arrangement C) the capacity value of any larger independent generation investment would be limited to the amount of other capacity investment avoided, and would not extend to existing capacity displaced. While its energy value would still be properly represented by the system marginal cost, this system marginal cost might be significantly reduced by the very existence of the large scale independent energy injections. Consumers under this arrangement continue to pay rates which cover the embedded cost of the NSPI fleet. While assets may become physically

redundant, their fixed costs can continue to be funded from the regulated rate consumers without harm. There would be no need to consider exit fees in such circumstances.

7.5, Billing systems

For the relatively small number of customers connected directly to the transmission system, the metering and billing system capability is unlikely to be an issue.

The extension of physical bilateral contract supply arrangements to distribution-connected customers could be an issue, depending on the capabilities of existing or planned NSPI billing systems. This would have to be addressed if such arrangements are under consideration.

7.6, Treatment of transmission and distribution losses

Definitive treatment of null energy and spill prices must recognise that these prices are applied to quantities at the generator bus, so must exclude any avoided costs associated with transmission and distribution losses. Back-up and top-up pricing would typically also be at the generator bus and would be at the same level, applied to the load top-up and associated transmission losses.

Distribution looses would only be applicable to any customers served at distribution voltage. Distribution loss adjustments would only become relevant to the extent that distribution customers become eligible to take unbundled distribution service and physical electricity supply contracts with independent generators.

8, Suggested discussion topics

The following list of potential discussion topics is not intended to be exclusive.

Section 3, Contractual arrangement options

Q 3.1, Do the options considered cover all options that generation developers and buyers (other than NSPI) would contemplate? What other options should be considered?

Q 3.2, Is each option adequately described? Do any options have significant features that are not identified here? What are these?

Section 4, Energy pricing principles

Q 4.1, Do you agree with the range of energy pricing principles set out here? What would you change, and why? What other principles should be considered? Should these principles be prioritised?

Section 5, Pricing options and issues

Q 5.1, Do you agree with the list of issues at the start of section 5?

Q 5.2, Are marginal or average energy costs the more appropriate basis for each of null energy, spill energy, back-up energy and top-up energy?

Q 5.3, If energy rates are to be based on NSPI's marginal cost, what if any adjustments should be added or subtracted for each purpose?

Q 5.4, Do you agree with the arguments for hourly pricing? What else would you propose and why?

Q 5.5, Section 5.3 discusses the limitations of financial contracts for the purposes of electricity price hedging if null energy is priced at marginal cost. Given the relative price expectations and the relative price risk, do you see this as a material obstacle to development at this stage? If so, how would you propose to resolve this? Does the enablement of physical contracting through tariff extension bring any material benefit.?

Q 5.6, Do you agree with the principles for capacity pricing set out in section 5.4? Do you agree with the methodologies set out there?

Q 5.7, Two alternative methods of allocating incremental ancillary services cost are considered in section 5.5. Do you agree with the conclusion of that section? What other matters should be considered?

Q 5.8, Section 5.6 identifies a possible concern over the implications of attribute export, but indicates that there should be no need for specific pricing treatment to discriminate between null energy associated with exported attributes and null energy associated with attributes retired in Nova Scotia. Do you agree?

Q 5.9, Sections 5.7, 5.8 and 5.9 identify other issues, but do not conclude that these have material impact in determination of the regulated price structures. Do you agree?

Section 6, Analysis of each price requirement

Q 6.1, For null energy, do you agree with the proposed:
- Applicability (renewable and possibly co-generated, but not other)?
- Price determination comprising payments for scheduled energy and for capacity?

Q 6.2, For spill energy, do you agree with the proposed:
- Applicability?
- Price determination comprising payment for scheduled energy only?

Q 6.3, For back-up and top-up energy, do you agree with the proposed:
- Applicability?
- Price determination comprising charges for scheduled energy and for capacity reservation for firm service ?

Q 6.4, What other terms or price elements are appropriate?

Section 7, Other issues

Q 7.1, Are there any other “other issues” that should be addressed at this time?

Q 7.2, Do you agree with the general conclusions that the “other issues” are not immediately impactive on rate designs, but may need to be kept under review?

Section 8, suggested discussion topics

Q 8.1, What have we missed?