Commission for Electricity Regulation

An Coimisiún um Rialáil Leictreachais

Responses received to Consultation Paper CER/01/30- Handling of CHP Plant in the Trading and Settlement Rules

CER/01/67

6 June 2001

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This report has been produced as a result of a consultation process conducted by the Commission for Electricity Regulation. On 12 February 2001 a consultation paper, Treatment of CHP Plant Under the Trading and Settlement Code, was published and comment was invited. Ten responses were received from different organisations, each listed below, and this report summarises the comments made which were considered in the formation of the Commission's Draft Decision CER/01/66.

The Commission wishes to express its thanks to all contributors for their valuable input to this process.

Respondents

Aughinish Alumina
Ballyragget Power
Bord Gáis CoGen
ESB Regulatory Affairs
ESB National Grid
Fingleton White & Co.
Glanbia
IBEC
Irish Refinery Company
Irish Wind Energy Association

General Comments

One respondent proposed that, in general, the considerations in this paper be extended to all non-dispatchable generators who generate primarily for the purpose of self-supply. The respondent contended that to do otherwise would be to discriminate against wind energy in favour of CHP. As wind is a green source of electricity and as the Commission has a duty to promote renewables, the respondent argued that to not extend the proposals to “wind self suppliers” would be against the spirit of the duties of the Commission.

One respondent asserted that in general terms, the consultation document provides a positive approach as to how CHP plants may accede to the Trading and Settlement Code.

One respondent welcomed the paper in general and its underlying effort to facilitate CHP plants to trade electricity in the deregulated market.

One respondent are in general agreement with the stated principles

One respondent noted that the paper is written for the conventional CHP arrangement where the CHP supplies heat and power to the MHC on the one site. Where surplus power from the CHP is traded on the bilateral market in accordance with the rules of the code, the respondent argued that this does not simply mean exported to the grid, this being termed "spill". The respondent argued that where there is no surplus or it is simply exported to the grid at the respondent’s site, there should be no requirement to accede to the Code.

One respondent welcomed the paper as a reflection of the additional attention being paid by the CER to the needs of CHP/ Autoproducers in a deregulating energy market and viewed this as a positive development.

One respondent requested further simplification of the rules, which would prove beneficial, particularly for small scale embedded plant. In addition, the respondent also requested that all administrative burden be reduced and where possible eliminated.

In responding to this consultation paper, one respondent considered that the paper is a positive step toward providing greater clarity regarding the possible arrangements for CHP plant owners and MHCs (Main Heat Customers). It was asserted that the paper would benefit further by providing more detail in some specific areas.

Comment on Principles

Principle 1

One respondent argued that there is no reason why a CHP plant that never exports should need a licence.

Principle 2

One respondent argued that a CHP plant should be able to supply the host site without a licence if there is no export.

One respondent commented that a CHP plant should be able to supply the host site without a licence if there is no export of electricity

It was asserted that Principle 2 should clarify the licencing requirements if MHC is an eligible customer.

Under Principle 2 it is stated that 'If a CHP plant is to supply electricity to the main heat customer [MHC] of the plant and the MHC is not an eligible customer, a separate 14(1)(d) Supply Licence is required to be held, either by the holder of the 14(1)(a) Generating Licence or some other person which can be the person who is the MHC.' The respondent argued that the logic of the customer (MHC) holding a 14(1)(d) Licence for a plant that is supplying itself needs some further explanation.

Principle 3

One respondent noted that it seems inequitable that a supplier of CHP electricity to a final customer does not need a supply licence or to accede to the code on the grounds that they are not trading but that the Commission is proposing that an AER generator does need to accede to the code despite the obvious fact that they are not trading.

Principle 5

One respondent asserted that the principles should clearly state entitlements in the event that the holder of the 14.1(d) licence accedes to the code [principle 5 states entitlements in the event that the 14.1(a) holder accedes to the code].

Principle 6

One respondent noted that the proposal that units greater than 10MW (or site greater than 30MW) will be subject to central dispatch is sensible, but for clarity the rules should also state that CHP below the above size is not subject to central dispatch.

One respondent agreed with the principle that CHP plants less than 10 MW output should not be obliged to be centrally despatched. However, if an existing 10 MW CHP plant wished to install a third turbine increasing the capacity to 15 MW there is still no reason to have it centrally despatched. If the MHC consumes the majority of the output, central despatching should not be obligatory.

Another respondent agreed with the proposal that units greater than 10 MW (or a site greater than 30 MW) be subject to central dispatch, but requested that it be stated that CHP below 10 MW is not subject to central dispatch.

Principle 8

One respondent noted that the majority of the electricity consumed by the MHC is generated in the CHP plant. However, it is an importer of and exporter of electricity, sometimes even in the same half hourly period.

One respondent agreed in principle.

Principle 9

One respondent contended that a holder of a supply license under Section 14(i)(d) of the Electricity Regulations Act 1999, should be permitted to sell electricity to eligible customers.

In principle the respondent agreed with point 9. However the respondent sought clarification with regard to which period is to be measurable? The respondent suggested that the period for measurement should be the monthly billing period. The respondent also noted that the England and Wales trading site system is the most comprehensive solution. It defines a site as either a net generator or a net importer. It provides a further incentive for plants to be net generators during time of peak system use by means of the triad periods. Since the paper recognises that the costs are largely fixed (and governed by capital requirements to meet peak demand), this system charges the users whose demand determines that investment. It also has the advantage of being a tried and tested system.

Principle 10

One respondent argued that it seems inequitable that a CHP generator who is not centrally dispatched will be allowed to net meter and to not extend this to other forms of non-centrally dispatched green generation where the generation is primarily for the purpose of self-supply. A farmer or householder with a small wind turbine would be a good example.

One respondent noted that concessions are proposed in the paper for smaller CHP units in Principles 9 and 10. One of the major problems facing any CHP plant whether small or big is that the site load at the MHC will have variability and this will result in variability of the net site export. In principles 9 and 10 the paper has permitted non-centrally dispatched plants the opportunity to mitigate the effects of this variability by allowing them to net off imports and exports from the overall site for each trading period. Principle 10 also allows net off from multiple units on a multiple unit site. The respondent contended that the Commission must also address the similar problems experienced by Centrally Dispatched CHP plants. It is impractical in this case to allow uncontrolled netting off. The system should grant CHP plants a higher dispatch tolerance as has been granted in other jurisdictions. The present rules allow a dispatch tolerance of plus or minus 2%, which is aimed at regulating the technical variability of a stand-alone CCGT. A CHP plant will be subject to similar variability but will also have its net export subject to the variability of the MHC load. If it is wished to maximise the benefits nationally of CHP plant the tolerance level should be increased to plus or minus 10%, or plus or minus 5 % as a minimum.

One respondent commented that the proposal for net metering for each trading period is agreeable.

One respondent stated that the proposals for net metering for each trading period is sensible.

One respondent noted that though the import and export meter readings would be netted for <u>each trading period</u>, it is important that separate import and export meter readings are available for each trading period.

In keeping with need for simplification in the running of small scale embedded plant, one respondent requested that the CER propose an extended 'trading period' for aggregation of power flows across a site boundary. The frequency of Ex-Post nomination must be such that the process is economic realisable. For many potential CHP developments, revenues accruing from annual exported power is below £4,000. Profit from such ventures are less than one tenth the revenue level. Clearly the administrative burden of Ex-Post nomination would render such a venture, unfeasible. Given the competing electrical efficiency of CCGT plant, grid exports from CHP must be simultaneously accompanied by sale of heat. Under these conditions plant efficiencies are in excess of 80%. The respondent requested that the CER propose an 'extended trading period' for small scale CHP below a de-minimis limit (10 MW) in the forthcoming draft paper. It should be borne in mind that <u>annual aggregation</u> of power flow for settlement purposes apply to small scale embedded plant other deregulated markets.

Principle 11

With regard to principle 11 one respondent was of the view that settlement for TUoS may be performed on the basis of net import and net export across the site boundary only if the metering is at the same busbar and the same voltage level. The respondent suggested that the following aspects be considered in the definition of a "Site":

- The site or facility is electrically to one bus only: connection to two busses would constitute two points of tariff application.
- There is one owner/tenant at the site or property
- The site or facility property is contiguous property not extending across public roads or road allowances

Principle 13

In relation to Principle 13, one respondent requested clarity, whether the technicality of two Market Participant ID's will effect an embedded plant the ability to purchase Top-Up to an 8% limit as per the situation for a 'pure' Genco.

One respondent queried if a embedded Genco identified as a Supplier would be subject to Supplier Top-Up rights (5%) during outages?

One respondent stated that the intent of the term "primarily licenced" should be explained in principle 13.

Comment on Scenarios

One respondent made a comment regarding all scenarios stating that the only metering necessary is import/export meters at MHC-ESB interface and that other metering is a matter of commercial negotiations between the CHP operators and the MHC.

In the case of a CHP generator with a generating licence or generating licence and supply licence, one respondent assumed it would be permissible to transfer responsibility for top-up and spill requirements to a third-party independent supplier. The scenario the respondent envisaged is one where a CHP Genco enters into an agreement with a third-party supplier to provide back-up electricity for the CHP plant and where the supplier buys top-up electricity on behalf of the Genco.

One respondent requested darification of what happens when the CHP Genco has a generating licence, the Genco is responsible for imports of electricity and for all the electrical demand of the MHC and the MHC is the holder of a supply licence and enters into a contract with an independent supply company to sell surplus electricity.

One respondent noted that in some of the scenarios described it is suggested that the Genco would be eligible to pay "for fixed charges on the basis of the CHP plant capacity, and for variable charges on the basis of their traded quantity on the network." Based on the respondents proposed TUoS tariff arrangements a CHP plant would be eligible to pay the appropriate generation locational UoS charges, consistent with its Maximum Export Capacity (MEC). This is a capacity charge. There are no TUoS energy related charges for generation.

Scenario 1

One respondent queried whether it is possible for the responsibility for trading to be separated between the two parties so that

- the Genco is responsible for all imports of electricity
- the supply company (MHC) is responsible for all exports of electricity from the site.

The logic behind the CER's metering proposals is acknowledged. One respondent noted that many small-scale CHP schemes, find simplification of these rules beneficial. Due to small auxiliary loads (taken from within the MHC's site boundary) of embedded generation, metering is sometimes omitted or installed to class 3 accuracy limits. Such decisions are taken where the marginal cost of class 1 metering is prohibitive relative to the value of power flows across that meter. It should be noted that all such metering is within a site boundary and by mutual consent of both contracting parties.

One respondent stated that it was less certain about the assumption that the person who holds the 14(1)(d) licence can avoid being a Participant under the Code. (Scenario 1 states: "The holder of the 14(1)(d) Supply Licence would not be required to accede to the Code"). The respondent noted that only a Participant can either register a Bilateral Contract purchase under the Code or buy Top Up.

1) If the site is a net importer (and the imports are met by Top Up Purchases); or
2) if there is a Bilateral Contract with GxxD as the seller and (as the case may be) SxxH or SxxB as the buyer (and there is no matching Bilateral Contract with SxxH or SxxB as the seller and some licenced supplier as the buyer);

Then the purchaser of this electricity supplies the MHC.

The Act says:
"14.—(1) The Commission may grant or may refuse to grant to any person a licence— …(d) to supply to the single premises of the main heat customer electricity which is produced using combined heat and power at the generating station from which that main heat customer is supplied with heat, or electricity purchased, in place of such electricity, in accordance with the trading arrangements provided for in regulations to be made by the Commission under *section 9(1)(d)*,"

The respondent argued that this means that only the person with the licence could supply the electricity (and thus only the person with the licence could buy electricity through a Bilateral Contract or through Top Up to meet the MHC's demand). Furthermore the modification to Section 35, sub-section (1) of the 1927 Act (given in Section 42 of the 1999 Act) seems to confirm this the respondent asserted. The resulting modification to the 1927 Act reading: "… no person (other than the Board) shall sell electricity or supply electricity for sale unless he … is a person authorised by … a licence granted under *section 14* of the *Electricity Regulation Act, 1999*, to supply electricity."

One respondent noted that a Generation Licence, issued under 14(1)(a) of the Act does not allow the generator to supply final customers, but only to supply other licence holders (14(8) says: "The holder of a licence granted under paragraph (a) of subsection (1) may supply electricity to the holder of a licence granted under paragraph (b), (c) or (d) of that subsection or to the Board…").

The respondent argued that although section 14(1)(a) of the Act allows the CER to grant a licence to generate electricity there does not appear to be in either the Act or the 1927 Act an express prohibition on unlicensed electricity generation. One might therefore conclude that an operator of a CHP station, or indeed any other power station, does not need a section 14(1)(a) licence to generate electricity. It does appear to need a licence to either sell the electricity that it produces or to "supply electricity for sale". This licence could, however, be a 14(1)(d) licence (which allows the supply of: "…electricity which is produced using combined heat and power at the generating station from which that main heat customer is supplied with heat, or electricity purchased, in place of such electricity ..."

The respondent noted that should the Commission direct the SSA to accept an Applicant who does not have a Licence as a Supplier or Generator, the SSA would concur.

Scenario 2

One respondent requested confirmation that in this case only the net amount of electricity traded across the site boundaries in each trading period would be treated under the Code.

One respondent was concerned about the suggestion, in Scenario 2, that: "…where the MHC has an exclusive contract with the plant owner to take all the electricity output from the CHP plant the MHC can be said to be the beneficial owner of the electricity and would apply for a 14(1)(a) Generating Licence". The respondent argued that the licence is a permission to generate (which arguably is not actually required by the Act) and to sell to other licence holders (which is requirement under the Act). Thus, under scenario 2 the owner of the CHP station can generate but can not sell the electricity to the MHC (or to the CHP Supplier selling to the MHC). In addition, it would seem to be important for operational reasons for the owner/operator of the CHP station to hold a Generation Licence. This is important in respect of Condition 4 of the Generation Licence: "The Licensee shall comply with the provisions of the Grid Code, Metering Code and Distribution Code insofar as applicable to it."
In summary, therefore, the respondent believed that (for CHP Sites):

1) Only a person with a Supply Licence (14(1)(b) or 14(1)(d), as appropriate) can sell to a final customer (the MHC) or have a Supplier MPID (SxxB or SxxH); and
2) Only a person with a Generation Licence (14(1)(a)) can sell the electricity produced by the CHP Station to the person holding the CHP Supply Licence or Eligible Customer Licence;

Scenario 3

One respondent requested assurance that a MHC holding a supply license under 14(i)(d) can accede to the code without it having the generation license. In other words, the owner of the asset holds the generation license. The respondent believed that this scenario should allow the MHC who holds the supply license trade its tradable electricity to its subsidiaries and the concern is that supply license 14(i)(d) currently prevents this.

One respondent stated that the distinction between Scenario 2 and Scenario 3 is unclear. Scenario 3 would seem to suggest that the MHC would not possess the 14.1(a) licence but yet would accede to the code as a generator, though the MHC would only possess a 14.1(d) licence. If this is the intent of Scenario 3, it is unclear on what basis a supplier should be permitted to accede to the code as a generator and further explanation is requested. The respondent was of the view that this arrangement would lead to confusion and that a MHC should specifically be prevented from acceding to the code as a Genco unless that MHC also possesses a 14.1(a) generator licence.

Diagrams

One respondent noted that the intent and purpose of the diagrams is unclear and further detail and explanation would be welcomed.

Implications for Trading and Settlement Rules Mechanics of Settlement

One respondent noted that it could see no problems with the mechanics of the Settlement process as described in the paper. This judgement was made on the basis that with dispatchable CHP sites, the meter readings that are available are on the basis of what would be read if the logical links are in place.

Simplified Accession to Code for smaller generation:

Three respondents welcomed the simplification of accession to the code for small generation and looked forward to commenting on the process.

One respondent welcomed the introduction of a threshold below which a generator might accede to the Code in a simplified manner, which would remove the need for submission of ex-post nominations.

One respondent stated that it took footnote 2 on page 3 of the consultation paper to mean that such Participants would not need to submit bilateral contract nominations (presumably there would be some mechanism to generate such “bilaterals” within Settlement).

TUoS and DUoS charging

One respondent noted that an embedded generator of less than 10MWs is not liable for TUoS capacity charges.

One respondent noted that Principle 10 in the CER paper proposes net metering for each trading period for non-centrally dispatched units. If this is also adapted for Transmission Use of System Tariffs, then it restricts charging on a gross demand basis. In the respondents response to the consultation paper on the treatment of Autoproducers, it was proposed that certain components of the demand system services charge should be charged on a gross metered demand basis, while other components should be charges based on a net basis (see table below). Consequently, principle 10 rules out this possibility (or alternatively, sets a de-minimus size for implementing the charge components proposed on a gross demand basis[1]). It should also be noted that embedded generators less than 10MW are not subject to the locational generation TUoS charge.

Demand Charge	**System Components**	**On-site Benefits Treatment**	**Demand**
1.	Operating Reserve	✓	"gross"
2.	Reactive Power	✓	"gross"
3.	Black Start	✓	"gross"
4.	System Support Services	✗	"net"
5.	Transmission Congestion	✗	"net"
6.	Dispatch Constraints	✗	"net"
7.	Market Operation and set-up	✗	"net"

One respondent noted that the charging regime for CHP UoS was consulted on separately to this consultation CER/01/30. Some UoS charges are referred to within the current paper, however the CER has not yet published a proposed decision arising from the previous consultation (CER/00/70 dated 15th November 2000). In the absence of clarity regarding the final proposed UoS charging structure for CHP, the respondent asserted that it is not possible to comment on the charges referred to in the current consultation and believed that such references should be removed pending the publication of the complete UoS charging structure for CHP.

The respondent believes that publication of the charging structure will provide further clarity, however in doing so, such charges will need to reflect the cost of having the necessary transmission infrastructure in place and should not be an influencing factor when deciding in what capacity a CHP or MHC should accede to the code.

One respondent argued that demand at the CHP site should be subject to a combination of fixed and variable charges, which are based on its maximum import capacity and metered demand. The respondent proposed in its response to the autoproducer that the network transfer charge should be charged on a net basis. It is the respondent's view that the demand system services charges should be charged consistent with the table above.
In relation to metering, in order to meet the data requirements for ESBNG's proposed TUoS charging basis, it would be necessary to meter any two of

- Gross generation
- Gross demand
- Net site import/export.

[1] The respondent agreed that in fact specification of a de-minimus size level, below which TUoS charging should be entirely on a net basis, is probably appropriate (due to metering and settlement costs).

It is not entirely clear to us that the metering proposed in each case is adequate to support the proposed charging basis.

One respondent raised serious concern with regard to the principle expressed in scenarios 1, 2, and 3, vis-à-vis UoS fixed charges on the basis of CHP plant capacity. The respondent was of the view, that UoS fixed charges should be based on export/ import capacity only. Therefore, the only metering required is export/ import metering at the MHC-ESB interface. The split on UoS charges between fixed and variable costs, if implemented along the lines outlined in the draft autoproducer paper suggests a fixed: variable split of 70:30. For a typical industrial demand site this ratio is acceptable as the fixed component is not far from the sites load factor. For embedded generation annual availability figures of 95% are achievable in most cases. Applying a fixed UoS component of up to 70% on plant of this nature is regressive. The charging mechanism is disproportionate to grid use and removes incentive for the plant operator to make availability targets (i.e. a plant pays on the basis of 70% of its capacity rating for a system used for less than 5% of the year).

One respondent stated that within the CER paper some confusion has been created by the reference to TuoS and DuoS charges in Scenario 2: MHC trading as Genco with a generating licence. TuoS charges are currently based on MIC or MEC, not on total plant capacity. The respondent stated that it would appreciate removal of this reference.

A respondent commented that there is a strong case for recognising that auto producers will be overcharged and will pay more for their fair share of network capacity if they are exporting and importing from the transmission network at different times. This is particular true one respondent argued for those who will be importing and exporting small volumes on a continuous basis and where there are no additional assets required for the demand use.

Impact of TLFs

One respondent noted the impact of TLFs on dispatchable units. Consider the case where the XNOM equals the actual output of the CHP Unit, which equals the MHC demand. For example, the CHP Unit has an output of 10 and the MHC has a demand of 10. Physically there is no export from, or import to, the CHP Site. The Bilateral Contract nominated is also 10. Let us assume a TLF of 0.993. The Supply side clears (Demand equals Bilateral Contract). On the generation side, however, we have that Bilateral Sales equals 10, but Tradable Quantity equals $10 \times 0.993 = 9.93$. The CHP Generator thus has to buy 0.07 at Top Up. The respondent would see the same situation with a non-dispatchable CHP unit if the Site generation and load were not netted off before settlement. At the moment there are no dispatchable CHP plants, however this situation may change.

Licences

One respondent stated that it understood that a 14(1)(d) licence was required to allow supply of electricity to a Main Heat Customer ("MHC") who is not an Eligible Customer. The respondent presumed that if the MHC is an Eligible Customer then either a 14(1)(b) or 14(1)(d) licence is required and queried whether this is correct?

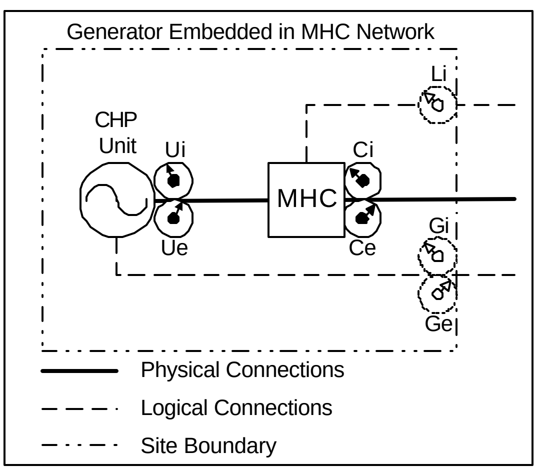
Allocation of MPIDs

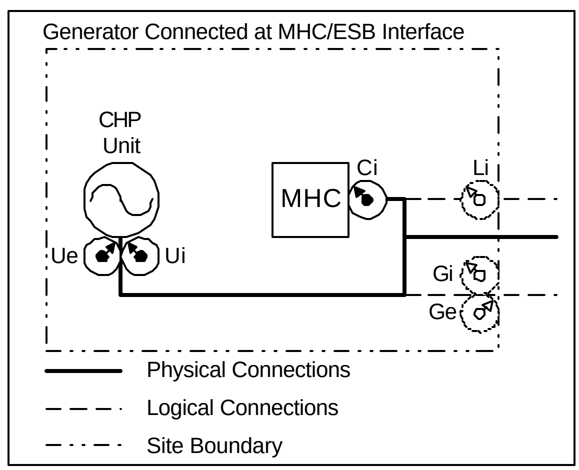
One respondent fully concured with the Commission's analysis of the requirements for there to be two Market Participant IDs ("MPIDs") for the site if any trading takes place across the site boundary. The respondent suggested that the MPIDs that should issue are as follows (where "xx" is a unique two digit alpha/numeric identifier):

1) CHP Generator: GxxD; and either
2) CHP Supplier (MHC customer is a non-eligible customer or eligible customer supplied under a 14(1)(d) licence): SxxH; or
3) Supplier (MHC customer is an eligible customer supplied under a 14(1)(b) licence): SxxB.

Dispatchable CHP Plant

The diagrams below are based upon those given in the CER's paper. The respondent reproduced them to allow specific definition of the values that will be seen on both the actual and virtual meters. The following meter numbering convention has been adopted: Ux means a CHP Unit meter, Cx means a MHC meter, Lx means a virtual Load meter, Gx means a virtual Generation meter (where x = i means an import meter and x = e means an export meter).





Consider the general equations for determining the readings on the various meters. In this analysis it is assumed that negative generation means that the unit is importing to meet the load of the auxiliaries.

Let the CHP Output be "CHP", the MHC Load = "MHC", the Site Load = SITEL and the Site Exports = SITEX. All meter reads are positive.

Generator Embedded in MHC Network

Ui = min(CHP,0) $\times$ -1 and Ue = max(CHP,0)

Ci = min(CHP – MHC, 0) $\times$ -1 and Ce = max(CHP – MHC, 0)

Li = MHC and Gi = Ui and Ge = Ue

SITEL = Li + Gi and SITEX = Ge

An alternative possibility is to delete Gi. The Li value would be calculated as follows:

Li = MHC + Ui

Generator Connected at MHC/ESB Interface

Ui = min(CHP,0) $\times$ -1 and Ue = max(CHP,0)

Ci = min(CHP – MHC, 0) $\times$ -1

Li = MHC and Gi = Ui and Ge = Ue

SITEL = Li + Gi and SITEX = Ge

An alternative possibility is to delete Gi. The Li value would be calculated as follows:

Li = MHC + Ui