Descriptive document

The new electricity market arrangements in Ukraine

A report prepared by ECS Project Office

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1. Structure of the Report

Subject Report describes a proposed set of arrangements and regulatory interventions required for the operation of a competitive electricity market in Ukraine, in accordance with the draft Law of Ukraine on the Electricity Market #4196 (herein after referred as the "draft Law").

The Report is organised in 13 Sections accompanied with two Annexes. The background and scope of this Report are presented in Section 2. Section 3 provides an introduction to the main market segments as well as to the various market participants and parties and to their respective roles in the market. Section 4 presents the operation of a forward market for physical products which is organised on a bilateral (over the counter) basis. Section 5 presents details on how the day- ahead market will be organised while section 6 discusses the basic principles for an Intra- Day Market operation. Section 7 presents the way the balancing mechanism will be organised and Section 8 gives a description of the mechanisms for operating reserves procurement. Imbalance settlements are discussed under Section 9. Section 10 presents the way the market is organised in respect of RES and CHP energy absorption at the wholesale level. Section 11 presents a set of various other arrangements required for a smooth market operation, including security cover requirements, metering profiling provisions, emergency arrangements etc. Finally the report under Section 12 briefly discusses the way Demand Response could be accommodated in the proposed market design, at a second stage.

2. Scope of the Report and Background

To comply with the obligations under the Energy Community Treaty, the Ukrainian authorities together with the Secretariat of the Energy Community (ECS) started the process of transposing the Third Energy Package by drafting the “Law of Ukraine on the Electricity Market”. The draft Law was submitted to the Parliament of Ukraine by the Government on March, 10 and registered with the #4196. It may be expected to be adopted by Parliament within the next months.

The Draft Law envisages a number of legal acts (secondary legislation) to be adopted by the governmental authorities, the national regulatory authority as well as the network operators. In this respect the ECS on the basis of a Grant Contract with the United Kingdom Secretary for State for Foreign and Commonwealth Affairs established a project office in Kyiv to work and draft a number of the required legal acts. As the Day Ahead and the Intra Day Market Rules and the Market Rules should be developed in accordance with the provisions of the draft Law, the project office in Kyiv identified the need for an updated document that sets the structural design of the wholesale electricity market in Ukraine.

Subject document comprises the outcome of the proposed design following discussions held with Ukrainian competent organisations.

The proposed design allows bilateral, over the counter, contracting of physical products on a forward basis while at the day-ahead stage a central market is organized. NEURC should regulate the minimum participation in the Day Ahead Market with a view to enforcing adequate liquidity. A continuous Intra-day market shall be organised to allow for better hedging of market participants towards the TSO.

Specifically, under the proposed design, bilateral physical forward contracts are notified and corresponding schedules are nominated to the Market Operator (MO) by the OTC market gate closure on the day ahead. Suppliers[1] and producers provide bid curves to a Day Ahead Market (DAM) on an hourly basis. Orders in the DAM are unit based in the case of producers[2].Suppliers (and/or consumers purchasing for their own use) submit orders based on individually forecast demand. Orders in the DAM should correspond to quantities not already contracted under bilateral contracts and take into account any reserve commitments. The DAM is centrally managed by the Market Operator (MO).

The MO runs a process of matching bid curves to optimise dispatch of residual volumes at the day ahead. Contracts resulting from the DAM are between market participants and the MO at

[1] or consumers entitled to directly participate in the wholesale market

[2] with the exemption of energy from RES for which the Guaranteed Buyer places a cumulative bid in the DAM

the DAM clearing price. A balancing market and a continuous intra-day trading platform will be organized to further support market operations.

3. Introduction to the market

3.1 Market Segments

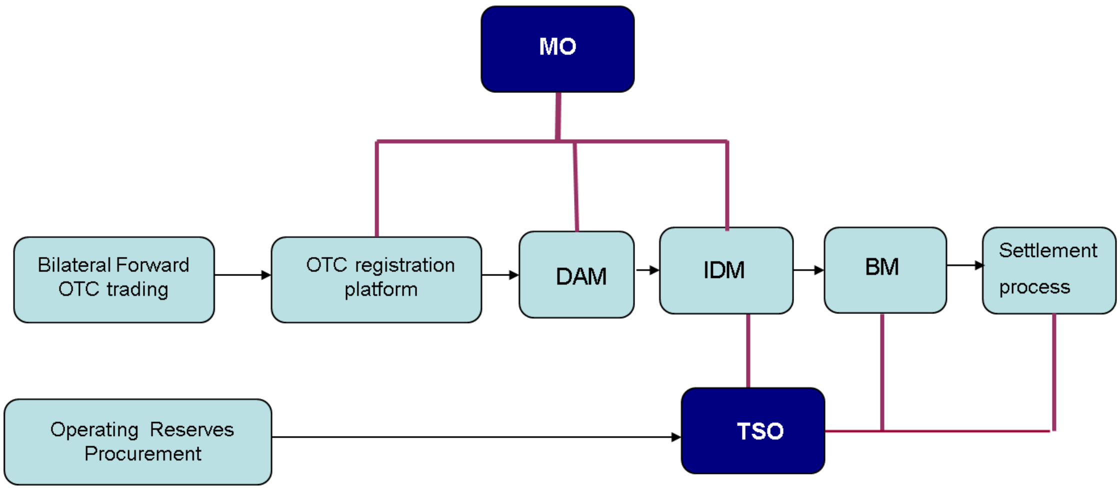

Figure 1- Proposed wholesale electricity market in Ukraine

The main new element introduced under the proposed new arrangements relates to the operation of a physical Day Ahead Market (DAM) and a continuous Intra- Day Market (IDM) through which licensed participants may buy and sell energy and modify their positions as close to real time as possible. The DAM is a market where energy products with physical delivery are traded, meaning that only participants representing physical injection and offtake points can submit orders to this market. It is clarified that the Regulator may allow some other licensed entities to submit orders in the DAM on behalf though of physical injection and physical absorption points.

The continuous IDM will allow all market participants (on both sides) to correct/ modify their positions as these have been shaped by any bilateral contracts they have entered to and the quantities cleared under the DAM. It is clarified that the participation in the IDM is made on a portfolio basis meaning that market participants can buy and sell quantities irrespectively of whether being absorption or injection points or traders.

With a view to fostering liquidity in the DAM, the draft Law foresees that the Regulator may set appropriate obligations (see discussion in para 5.8).

RES producers under green tariff as well as CHPs under regulated tariffs will enter contracts with the Guaranteed Buyer who will undertake to sell these quantities at the wholesale level i.e. under bilateral contracts or/and the DAM and/or the IDM. Moreover, the Guaranteed Buyer will undertake to become the Balance Responsible Party towards the TSO regarding the energy quantities produced under green tariff producers.

As provided under the draft Law, private solar installations at households not exceeding 30 kW of installed capacity will enter into a contract with universal supplier(s). The latter undertake the responsibility to buy all the energy quantities produced by these facilities, exceeding the corresponding monthly consumption of the household at the corresponding green tariff. For the purposes of representing these quantities at the wholesale segments of the market, the universal supplier(s) will always count corresponding quantities within their consumption needs i.e. these quantities will be netted with load (negative load approach).

RES plants outside the “green tariff” support scheme may either contract on a bilateral basis at the forward stage or bid into the DAM and/ or the IDM. Especially for RES producers that operate without “green tariffs” the detailed market rules should allow aggregation i.e. these RES producers could formulate groups and collectively place orders into the DAM. Direct participation to the wholesale market involves balancing responsibilities (either directly or through BRPs) similar to those imposed to any other producer. At a second stage these RES plants could also perform as BSPs.

Pre-requisite for participation in the IDM is the participation in the bilateral contracts market and/ or the DAM.

Apart from the bilateral transactions, the DAM and the IDM, a balancing process is operated by the TSO with a view to purchasing and selling energy quantities to balance the system (and manage any network constraints). All market participants should carry balance responsibility towards the TSO (either directly or through a BRP)in accordance with the detailed rules provided under Section 9,with the exemption of RES producers under green tariff, on behalf of which the Guaranteed Buyer carries corresponding responsibility, by default.

For the first years of wholesale market operation, under the proposed new arrangements, it is envisaged that balancing services will be mandatory for all thermal units with installed capacity above [X] MW and dispatchable hydro units for the capacity that has not been committed under reserve contracts, OTC contracts, the DAM and the IDM. Load holding appropriate capabilities (Dispatchable Load) may participate to balancing services’ provision.

The TSO, following NEURC’s approval, may allow RES producers outside green tariffs (and RES aggregators) to offer services to the Balancing Market on equal terms and obligations compared to those applied to thermal and dispatchable hydro units and dispatchable load. Obviously this requires that the RES plants hold appropriate technical equipment that will allow the process to treat them under the same arrangements.

In general, at the wholesale level all transactions are envisaged to take place at non-regulated prices. However, some limitation to the upper and lower levels is proposed as the market may face, at least in the beginning, phenomena of market power exercise.

Figure 1 above presents the proposed wholesale market structure.

Wholesale market arranges the settlements and cash flows among participants in the wholesale market (as these are presented in paragraph 3.2 below). Suppliers of end consumers and self-supplied end consumers further activate to the so called retail market. In the retail market there are regulated cost components such as the PSO or the tariffs for the use of the transmission and distribution systems that should be separately charged and upon collection, by suppliers of end customers or by the customers themselves in case they are self-supplied, directly forwarded to the entities providing the services or first to a central entity (as the TSO) and then to those providing corresponding services.

The MO is responsible for the operation of the DAM and the IDM as well as for the registering of bilateral contracts (the latter though do not involve any clearing for the MO). DAM and IDM are cleared in advance of real time. The corresponding calculations are made by the MO. The MO may undertake as well the clearing i.e. the money transfer among participants (European exchanges do so) or assign it to a third entity (e.g. a clearing house).

After real time there are other transactions (balancing and reserves procurement, imbalances and system costs) that have to be cleared. This clearing, as a process, is made separately from DAM and IDM clearing. The calculations are made by the TSO for these activities. The clearing however, can be done either by the TSO or by a third entity (e.g. a clearing house) which should undertake the corresponding risk as well.

In case a third party i.e. a clearing house is introduced then it makes sense to undertake all above clearing processes.

3.2 Participants to the Wholesale Electricity Market

This paragraph sets out the relationship between the Participants, and their primary roles in the electricity market. All Participants (except consumers) will hold a license issued by NEURC appropriate to their role in the market. Participants may accede to the DAM Rules, the IDM Rules and the Market Rules (collectively referred hereinafter as “wholesale electricity market rules”) in more than one capacity.

The following Participants should accede to the wholesale electricity market rules in order to participate in the proposed electricity market arrangements:

- The Transmission System Operator of Ukraine(TSO)
- The Market Operator of Ukraine(MO)
- The Distribution System Operators (DSOs)
- Producers with:
    - Thermal Generating Units connected to the Transmission System; or

    - Thermal Generating Units connected to the Distribution Systems with a nominal installed capacity greater than [X][3]MW; or
    - Nuclear generation units; or
    - Hydro Generating Units with installed capacity above 10 MW, i.e. hydro units that do not operate under green tariffs, including pump storage units (hereinafter referred to as dispatchable hydro units); or
    - RES Power Production Sites operating outside green tariffs
- Aggregators of RES plants operating outside green tariffs
- The Guaranteed Buyer
- Suppliers of end consumers
- Traders
- Consumers purchasing energy for their own use
- Balance Responsible Parties (BRPs) The Settlements Administrator
- The Commercial Metering Administrator

The Participants, and their respective roles in the Wholesale Electricity Market, are the following:

- **Transmission System Operator (TSO):** its main tasks include the operation of the transmission system and the physical balancing of the system under the terms of the Transmission Electricity Network Code. As far as it concerns the market operation, the TSO carries the responsibility to submit transmission system meter readings for settlement purposes. The TSO is also responsible to forecast load at national level, check feasibility of scheduling towards network constraints and procure balancing energy and ancillary services from, and on behalf of, market participants. The TSO can therefore levy Market Participants charges for network and system operation services (following NEURC's approval). The TSO shall not own generating capacity or trade in energy for profit. It is allowed though to purchase/sell energy quantities only to compensate for losses and balancing. The TSO should publish all information relevant to the system operation as per the EU Regulation543/2013 and EU Regulation 1227/2011 known as REMIT Regulation. The TSO should hold and manage its own accounts with a view to performing above responsibilities.
- **Market Operator (MO):** The MO will be a licensed entity responsible for the operation and settlement activities of the centrally managed markets i.e. the DAM and the IDM. Admission to the Market Rules would be a license requirement. The MO will be responsible for the registration of all bilateral, Over the Counter (OTC) forward contracts between Market Participants, including the reception of technical declarations and nominations which are be submitted to the TSO and copied to the MO. The MO will be responsible for the operation and settlement of the DAM and the IDM

[3]i.e. units carrying the possibility to meter and transmit to the TSO production data for every settlement period.

and will assess the feasibility of the scheduling resulting from the bilateral, day-ahead and intra-day markets. The MO will act as the central counterparty for the financial settlements between market participants with regard to energy quantities cleared through the DAM and/or the IDM. Information publication requirements will be applied to the MO with a view to allowing smooth operation in the market. The MO shall not own generating capacity or trade in energy for profit. The MO should hold and manage its own accounts with a view to performing above responsibilities and report data. It is proposed that the MO develops an efficient software platform that will also allow it to report data in accordance with EU Regulation 1227/2011 known as REMIT Regulation.

- **Settlements Administrator**: The SA registers balance responsible parties and balancing services providers, receives by the TSO and registers data regarding reserves, receives and registers Final Physical Positions of market participants and Net Positions of BRPs, ensures BRPs and BSPs provide appropriatefinancial guarantees under the Balance Responsibility and Balancing Services agreements, calculates volumes and cash flows in accordance with the Market Rules andundertakes the financial settlement of the reserves and balancing market as well as the imbalance and other market uplift settlements. The Settlements Administrator should hold and manage its own accounts with a view to performing above responsibilities.

- **Commercial Metering Administrator**: The CMAis an entity providing organization and administration of commercial electricity metering in the electricity market, which fulfills the function of centralized aggregation of commercial metering data. It registers commercial metering service providers and commercial metering points; it administers metering data exchange between market participants, obtains electricity commercial metering data from commercial metering service providers and forwards it to the settlements administrator and other electricity market participants;creates and manages corresponding databases. The CMA needs no account in the wholesale market.

- **The Guaranteed Buyer**:

    - a) with regard to the RES under green tariffs, should notify any bilateral energy contracts it holds (sales of RES energy) on a cumulative basis (not per plant), forecast and nominate physical delivery on a cumulative basis at the day-ahead stage and submit orders in the DAM on a cumulative basis.

    - b) with regard to the CHP under regulated tariffs, should notify any bilateral energy contracts it holds (sales of CHP energy) on a per unit basis, nominate physical delivery on a per unit basis at the day-ahead stage and submit orders in the DAM on a per unit basis. Physical Delivery Nominations and Orders in DAM and the IDM should be made based on the quantities declared by the operators of the CHP plants. Any imbalance costs will be then directly charged by the TSO to CHP operators.

The Guaranteed Buyer may also participate in the IDM and should hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO.

- **Distribution System Operators (DSO)**: their main tasks include the operation of the distribution systems under the terms of the Distribution Electricity Network Code. The DSOs will undertake to inform the Commercial Metering Administrator on the meter readings .The DSOs may outsource meter reading and certification services. The DSOs shall not own generating capacity or trade in energy for profit. They are allowed though to purchase/sell energy quantities only to compensate for losses in their networks. The DSOs should hold and manage their own accounts with a view to performing above responsibilities.

- **Producers**: thermal producers connected at the transmissions network and those connected at the distribution network with nominal installed capacity above [X] MW[4]should notify any bilateral energy contracts they hold to the MO (including any forward import and/or export contracts), obtain transmission capacity rights, submit declarations of their technical data, participate to reserves tendering, nominate physical delivery on the bilateral contracts registration platform, submit orders to the DAM for energy injections, participate in the IDM (on a voluntary basis),submit bids and offers in the balancing market, and hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO.

- **Producers with dispatchable hydro units:** should notify any bilateral energy contracts they hold to the MO (including any forward import and/or export contracts), obtain transmission capacity rights, submit declarations of their technical data, participate to reserves tendering, nominate physical delivery on the bilateral contracts registration platform, submit orders to the DAM for energy injections, participate in the IDM (on a voluntary basis), submit bids and offers in the balancing market, and hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO.

- **Nuclear Power Plants:** connected at the transmissions network should notify any bilateral energy contracts they hold to the MO (including any forward import and/or export contracts), obtain transmission capacity rights, submit declarations of their technical data, participate to reserves tendering, nominate physical delivery on the bilateral contracts registration platform, submit orders to the DAM for energy injections, participate in the IDM (on a voluntary basis), submit bids and offers in the balancing market under corresponding technical standards and capabilities, and hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO.

[4]Thermal generating units below [x] MW should be reported as negative load, under bilateral contracts with suppliers/end consumers. The negative load approach for small units is adopted as these units will not have the means to directly participate and access the wholesale market.

- **RES plants operators operating outside green tariffs[5]:** RES plants operators operating outside green tariffs have the possibility to either participate through an aggregator or individually on a per plant basis. In the latter case, RES operators should notify any bilateral energy contracts they hold, per plant, to the MO, submit declarations of their technical data, forecast and nominate generation scheduling on a day-ahead basis per plant, submit orders to the DAM, participate (on an optional basis) in the IDM, and hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO. Direct participation entails balance responsibility either directly or through a BRP.

- **Aggregator of RES plants operating outside green tariffs:** Aggregators of RES plants operating outside green tariffs should notify the MO of any bilateral energy contracts they hold on a cumulative basis, submit declarations of the technical data of the RES power plants they represent, forecast and nominate physical delivery on a day-ahead basis on a cumulative basis, submit orders to the DAM on a cumulative basis, participate (on an optional basis) in the IDM and hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO.

- **Suppliers of end consumers**: suppliers of end customers should notify any bilateral energy contracts they hold to the MO, submit meter representation declarations, place orders (on an optional basis)in the DAM regarding their offtake quantities, participate (on an optional basis)in the IDM, place bids and offers to the balancing market (optional)and hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO.

- **Traders:** these are licensed entities that should notify their bilateral energy contracts to the MO. As the bilateral contacts market is a physical market, traders and should only act as intermediaries in physical products trade. In this respect in the morning of D-1 , when generation units and consumption points have to be identified under bilateral quantities registration, traders' accounts should carry the obligation to sum to zero. Traders/wholesale suppliers may participate in the DAM representing though physical injections or absorption points (imports and exports are considered as injections and absorptions respectively). They can participate in the IDM on a portfolio basis. They should hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO.

- **Consumers purchasing energy for their own use:** should notify any bilateral energy contracts they hold to the MO, place orders (on an optional basis)in the DAM regarding their offtake quantities, participate (on an optional basis)in the IDM, place bids and offers to the balancing market (optional and provided they hold appropriate technical capabilities) and hold appropriate accounts for the purposes of the settlements performed by the MO and the TSO.

[5] RES plants operators operating outside green tariffs: electricity producers utilizing RES for which no "green tariff" applies under the provisions of the Law.

- **Balance Responsible Parties:** BRPs are entities that undertake the financial responsibility towards the TSO with regard to the imbalances registered for a group of market participants as provided under para 9.4.

3.3 Admission to the DAM and the IDM

Market Participants wishing admission by the MO must submit a DAM and IDM Participation Application accompanied by a signed DAM and IDM Participation Agreement; in the Agreement, the contracting party (Market Participant) must state that he/she is aware of and accepts the DAM and IDM Market Rules. Pre-requisite for the participation to the DAM and IDM Rules is the admission of subject market participant by the TSO into the Market Rules as per paragraph 3.4 below.

Upon admission, the applicant acquires the status of DAM and IDM Market Participant. The MO should create and maintain a DAM and IDM Market Participants Registry.

The DAM and IDM markets will be managed through an information system to which participants will have access through the Internet. Access to the information system is based on personal identification of users-participants.

Admission of the MO should be directly ruled through its licensing terms.

3.4 Admission by the TSO

Market Participants wishing to perform transactions at any wholesale market segment should submit to the TSO a Market Rules Participation Application accompanied by a signed Market Rules Participation Agreement; in the Agreement, the contracting party (Market Participant) must state that he/she is aware of and accepts the Market Rules.

Upon admission, the applicant acquires the status of Market Participant. The TSO should create and maintain a Market Participants Registry.

Market participants wishing to become BRPs and/or BSPs should further declare this within the above mentioned agreement with the TSO.

The balancing market and settlements will be managed through an information system to which participants will have access through the Internet. Access to the information system is based on personal identification of users-participants.

Admission of the TSO should be directly ruled through its licensing terms.

4. Forward Market

4.1 Bilateral trading

Forward trading will be carried out on a wholly bilateral basis. For the time being, no central platform for forward contracts will be created, therefore trading is expected to take place exclusively Over the Counter (OTC).

In time though, it will prove useful that a central platform for forward and financial future products' trading, is created. Considering that today the country is operating on a single gross pool status, for the first years of the new market operation, the market design includes only OTC forward transactions as a first step towards a Power Exchange operation.

During the first years of market operation, NEURC with a view to enhancing liquidity in the day ahead market, may impose market participants specific terms and regulated minimum volumes to be traded in the DAM, indirectly therefore impacting on the maximum volume of OTC traded volumes.

NEURC should periodically review the market developments and progressively relax any trading restrictions.

4.2 Types of Bilateral contracts

Bilateral OTC contracts by the registration gate closure should refer to physical products respecting feasibility of physical flows between zones. This means that corresponding contracts should refer to specific obligations for electricity quantities injection-withdrawal.

Bilateral contracts may be traded, at the wholesale level, as options up to D-1 when they are either exercised or collapse. The MO should be capable for registering a variety of different bilateral contracts (base load, peak load etc.) making sure that overall these are matched for the corresponding hours (delivery periods) and counted to both the producer's and the supplier's (or end consumer's) accounts. For traders/wholesale suppliers that only act as intermediaries between injection and withdrawal, corresponding accounts in the bilateral contracts registration platform by D-1 should sum to zero.

The financial arrangements and corresponding security covers are handled bilaterally and the MO is not involved. The contracting process may occur either directly or through brokers, the latter usually undertaking to provide mainly for the financial security between counterparties, in exchange of a service fee.

The option of allowing bilateral OTC contracts to be also financially covered through the MO of Ukraine (as the case is in the Italian forward market whereas the GME, the Italian Market Operator, is undertaking the corresponding financial risks) is not proposed in this case as the financial risk imposed to the Ukraine MO should be the minimum. In the future and provided that the MO holds adequate financial risk management capabilities the OTC bilateral contracts may also be financially covered through it.

4.3 Contracts Registration, Physical Delivery and Physical Offtake Nominations and Validation

The MO should operate a platform where all market participants having traded electricity quantities on a bilateral basis will manually register corresponding quantities for all hourly periods of each trading day.

The platform will be open for quantities notification year ahead and shall close at 9:00 EET on D-1 for the quantities corresponding to the 24-hours of day D.

Up to hour 13:00 on D-2 contracts may be registered either on a portfolio or on a per unit basis. From this point onwards and up to the gate closure of 9:00 EET on D-1, registration should be made declaring the exact generating injection point (per unit or per plant in case of RES or per RES aggregator), the trader/wholesale supplier (if involved) and the retail supplier or end consumer offtaking quantities. The most updated registration made by 9:00 EET on D-1 is considered as the Physical Delivery Nomination of corresponding generating units and as the Physical Offtake Nomination of corresponding suppliers/end consumers. The sum of these quantities should match.

It is clarified that those producers having registered quantities on a portfolio basis should submit Physical Delivery Nominations on a per unit basis (or per RES plant or per RES aggregator) the latest by 9:00 EET on D-1. This is also the gate closure for Physical Offtake Nominations.

The platform at this point should check whether Physical Delivery and Physical Offtake Nominations are matched. Furthermore, at this point the MO checks whether the Physical Delivery Nomination respects each unit’s maximum capabilities (taking into account the capacity that should be left free in cases of signed Operating Reserves contracts, as well as any other capacity restrictions e.g. weather dependent or maintenance scheduling etc.).

Each market participant (either producer or trader or supplier/end consumer) registering quantities for any hourly period has to declare who the counter party is. In case of more than one counterparties, separate registrations should take place for the same hour.

On D-1 by 9:15EET, those producers, traders, suppliers and end customers having registered bilaterally traded quantities should receive either:

- a confirmation that the register transaction is valid or
- an inconsistency notification.

In case of mismatches and inconsistencies ,both counterparties are allowed to resubmit corrected and matching Nominations up to 10:00 EET. If they fail to do so until 10:00 EET on D-1 then corresponding nominations are validated up to the matched quantities meaning both counterparties are receiving a message that the mismatch quantity (actually declared by the one party) is not finally registered as bilaterally traded.

The latest by 10:30 EET, the MO should have completed corresponding validation process and issued appropriate confirmation and/or rejection tickets.

A feasibility rule applies as to the maximum quantities a generating unit can physically deliver. It is clarified thought that a Physical Delivery Nomination submitted by a generating unit does not need to respect the technical minimum constraint.

The above provision is introduced with a view to allowing generating units to exploit synergies with DAM and IDM participation. However, since the DAM and the IDM may or may not dispatch the remaining quantities (up to the technical minimum), it might happen that after the closure of the IDM, the generating unit is scheduled only for the non-feasible OTC Physical Delivery Nomination. In such cases the TSO will schedule this unit to zero and the corresponding quantities will be handled through the balancing market. Obviously the generating unit will be charged corresponding imbalances.

Market participants should arrange the physical delivery/offtake of the electricity traded within their bilateral contracts as per the validated Physical Delivery /Offtake Nominations.

It is clarified that OTC bilateral contracts should respect the physical constraints of the Ukrainian system.

4.4 Cross border forward trade

For imports and exports, the following processes should be followed:

- For all borders, after the long-term PTRs nomination deadline, the TSO should send to MO through the trading platform, the long-term PTRs that have been nominated (used), for each wholesale Market Participant and for each hour of day D.

- After the publication of the daily auction results (indicatively at 09:30 EET of day D-1), the TSO should send to MO, through the trading platform, the daily PTRs that have been acquired by each Market Participant for each hour of day D.

Given this data, long term PTRs – Physical Delivery/Offtake margins should be set by MO: Margins (energy quantity maximum limits) should be set in the Registration Platform, concerning the use of long-term PTRs by the market participants, for covering their forward physical positions. The margins should be equal to the nominations of long-term PTRs declared by the Market Participants to TSO (copied to the MO) at 07:00 EET D-1. By 9:00 EET D-1, if a Market Participant declares to the Registration Platform that part of his forward Position will be covered by imports/exports, if the import/export quantity is above the pre-defined margin (namely, above his nominated long-term PTRs), the declaration should be rejected, and a descriptive rejection message should be sent to the Market Participant through the Registration Platform.

It should be noted that Daily PTRs for imports / exports cannot be used for covering positions in the OTC Markets, due to the proposed timing in this document.

5. Day Ahead Market

5.1 The Day Ahead Market arrangements

The Day-Ahead Market (DAM) is organised as a wholesale electricity market, where hourly blocks of electricity are offered for the next day.

The DAM should be designed to host transactions of purchase and sale of electricity to complement the physical nominations registered earlier at the close of the OTC registration platform. Within the DAM, orders for energy injection are submitted separately to orders for energy offtake. This comprises a basic design choice. There are markets where participants have the possibility to trade on a portfolio (rather on a unit) basis. For an initial phase the unit based approach for participation in the DAM is proposed as this allows for better monitoring. At a later stage when the market matures, portfolio bidding could be applied as this is deemed to offer more flexibility to market participants.

Based on the above, Orders for energy injection should be submitted per generating unit (or per RES plant or per RES aggregator).

Market participants owning generating units are obliged to offer all their available capacity (i.e. capacity that has not been nominated at the OTC registration platform or contracted under operating reserves contracts) **in the DAM**.

This is a measure to be applied during the first years to enforce liquidity and prevent IDM or balancing market abuse through capacity withholding but on a later stage it could be relaxed as an obligation and with-holding of capacity is only ex-post monitored.

RES operating outside green tariffs may also participate in the DAM by placing priced offers.

Must-run hydro (i.e. hydro quantities that need to be scheduled for other than market reasons) will be offered under zero prices with a view to taking priority in dispatch by the DAM algorithm.

Market participants wishing to schedule physical offtake may either do so by utilizing the Physical Offtake Nominations at the OTC registration platform or by utilizing the subsequent DAM, or both.

Imports are treated as generation while exports are treated as consumption.

The DAM opens at 10:30EET on D-1 (i.e. the day before the day of delivery) and closes at 13:00 EET on D-1.

The MO publishes the market results and notifies the individual market results to participants and to the TSO by 13:45 EET on D-1.

All parties that have acquired the status of DAM Market Participant may trade in the DAM. The MO acts as the central counterparty for the purchase and sale transactions concluded in the DAM.

Market Participants should submit technical declarations regarding the availability and other technical parameters of their generating units or RES plants (or major offtake points' capability) to the TSO copied to the MO for each day. They should also bear the responsibility to immediately inform the TSO and MO of any change in their availability (or major offtake capability).

The DAM and IDM trading platforms and the OTC registration platform may be executed by the same or different software systems. Considering that these operations will be assigned to the same body i.e. the MO and that there will be a significant amount of data to be transmitted from the one system to the another it makes sense that a single software platform is developed accommodating all above mentioned transactions.

Electricity transactions concluded in the DAM are binding for producers and suppliers. If corresponding quantities are not delivered (or absorbed), the generating unit (or the supplier) is subject to imbalances (either directly or through a BRP).Generating units may opt to purchase the energy quantities scheduled under the DAM through the IDM or the balancing market, in case they expect the prices in these markets to be lower than their own variable costs.

5.2 Day Ahead Market Interface with the Forward Market

The MO before accepting a generating unit's offer in the DAM should check whether this offer respects the maximum availability of the unit (taking into consideration the validated Physical Delivery Nominations at the OTC registration platform as well as any contracted reserve obligations, or any other capacity restrictions e.g. weather dependent or maintenance scheduling etc).

The OTC quantities validated under Physical Delivery Nominations and Physical Offtake Nominations are declared in the DAM as priority quantities i.e. as quantities that they are cleared by default.

5.3 Day Ahead Market Interface with the Balancing Market

Following DAM closure, BRPs should inform the TSO about the Physical Positions of their members. These positions are also copied to the MO and checked against the sum calculated by the platform.

The Physical Position of a generating unit is the outcome of its cleared DAM quantities. These quantities include the validated Physical Delivery Nominations of the forward OTC contracts.

The Physical Position of an offtaker is the outcome of its cleared DAM quantities. These quantities include the validated Physical Offtake Nominations of the forward OTC contracts.

If no transaction in the IDM takes place for a market participant, then its Physical Position is its Final Physical Position that will be taken into account in the BM.

BSPs on top of the above Physical Positions, submitted by BRPs on an hourly basis for the 24 hours of the next day, have to submit to the TSO detailed generation (or load) schedules indicating their capacity on a [5] minutes basis. These schedules, on an hourly basis, should give the same energy quantities as the hourly Physical Positions submitted by corresponding BRPs and they should be updated following the IDM trading.

5.4 Day Ahead Market Interface with the Intra Day Market

The Intra-day market should operate in a way that allows generating units, traders and offtakers to reschedule their total positions by selling and buying energy quantities on a portfolio basis in an intra-day centrally organised platform.

The re-scheduled nominations, after validated under the intra-day trading processes, should be communicated to the TSO to take them into account in the balancing process.

It is therefore critical the information system to be developed in a way to allow interfaces with a continuous intra-day trading process.

5.5 Cross border trading in the DAM

The Ukrainian system (with the exemption of the Burstyn Island) is not interconnected to the rest of ENTSO-E system. Burstyn Island operates totally isolated to the rest of Ukraine meaning that even if we approach the situation by creating one bidding zone at the Burstyn Island fully operating under the CACM NC provisions and another bidding zone for the rest of Ukraine similarly operating in full compliance with the CACM NC, there would be no interconnector[6]for implicit exchanges that would allow the rest of Ukraine to be coupled with the Burstyn Island.

Therefore, allocation of capacity in all interconnectors with European or Energy Community countries will be performed on an explicit basis in full harmonisation with corresponding

[6]as the case is with Estonia and Finland which operate under different synchronous systems but share an interconnector which allows them to couple

European legislation regarding explicit cross border capacity allocation in the forward, day ahead and intra-day timeframes.

At a second stage when Ukraine is ready to couple with other countries' markets, cross-border capacity in both the DAM and IDM stage will be performed implicitly.

For as long though, as explicit daily PTRs are auctioned, the Ukrainian DAM should set appropriate margins (energy quantity maximum limits) in the phase of submission of import/ export Orders in the DAM. The MO should compute for each DAM Market Participant and for each hour a margin for import / export Orders, corresponding to the daily PTRs acquired by the DAM Market participant for each interconnection.

The above margin is valid for both imports and exports. This information should be send by the TSO to the MO through the trading platform every day, till 10:00 EET D-1. Several other information transfer options could be acceptable, based on the design of the software platform(s) that will facilitate the wholesale market processes.

In case an import or an export Order, above this margin, is submitted by a DAM market participant, an Order curtailment should be applied in the step-wise ladder, up to the pre-defined margin (curtail offered energy quantities in the right side of the Order).

5.6 Type of Generating and Demand Orders in the DAM

When the DAM opens i.e. at 10:30 D-1, participants may submit orders where they specify the volume and the minimum price at which they are willing to sell energy, or the volume and the maximum price at which they are willing to buy energy.

Generating Orders (offers) must be consistent with the injection capabilities of the generating units to which they refer and they must correspond to the real **willingness and capability** to inject the related volumes of electricity.

In particular Generating Orders express the willingness to sell a volume of electricity not higher than the one specified within the order at a unit price not lower than the one specified within the order.

Demand Orders express the willingness to purchase a volume of electricity not higher than the one specified in the order and at a unit price not higher than the one specified in the order.

Import Orders are treated similarly to Generation Orders whilst Export Orders are treated similarly to Demand Orders.

The acceptance of a Generating Order involves the market participant's commitment to inject the volumes of electricity specified in the order, into the grid, in a given hourly period or, in case of partial acceptance of the order, the corresponding share of volume.

The DAM in Ukraine should be capable of accommodating Simple hourly Orders as well as Block Orders (at the same time). Both types of Orders are already in use either combined or individually, in the CWE region and in the Nord Pool.

Simple Hourly Orders involve Demand Orders from market participants which are aggregated into a single curve referred to as aggregated "demand curve" defined for each period of the day. Demand orders are sorted from the highest price to the lowest. Conversely, Generating Orders from market participants are aggregated into a single curve referred to as aggregated "supply curve" defined for each hourly period of the day. Generating orders are sorted from the lowest to the highest price.

As described in the PCR Algorithm, aggregated supply and demand curves can be of the following types:

- Linear piecewise curves (Figure 2) i.e. two consecutive points of the monotonous curve cannot have the same price, except for the first two points defined at the maximum / minimum prices of the bidding area or
- Stepwise curves (Figure 3) i.e. two consecutive points always have either the same price or the same quantity or
- Hybrid curves(composed by both linear and stepwise segments).

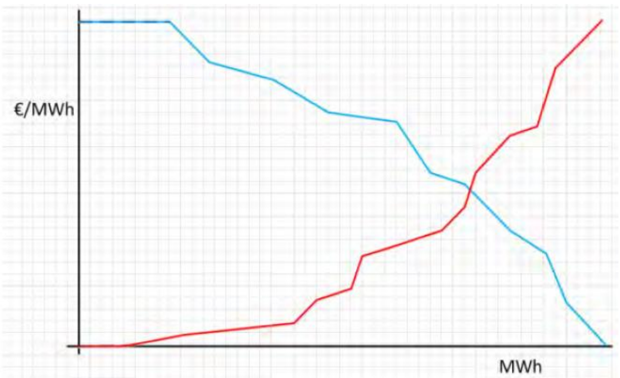

Figure 2- Linear piecewise aggregated curve

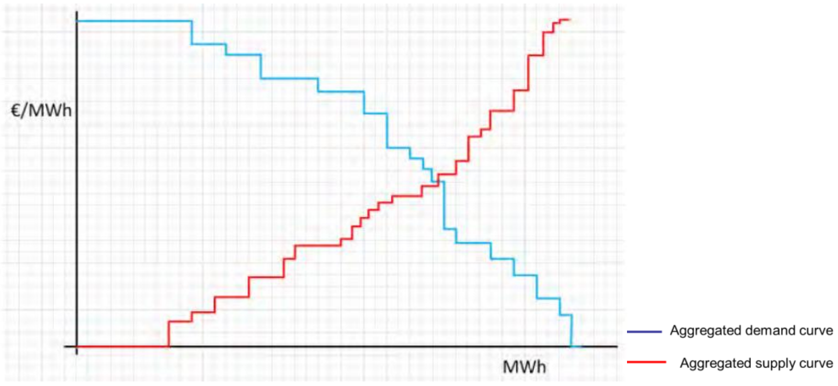

Figure 3- Stepwise aggregated curve

Demand Orders may be priced or not. A non-priced Demand Order means that the corresponding Supplier is willing to pay any price to accommodate its needs (Figure 4). The DAM software should be designed to allow for decreasing hourly load orders in the form of energy-price pairs.

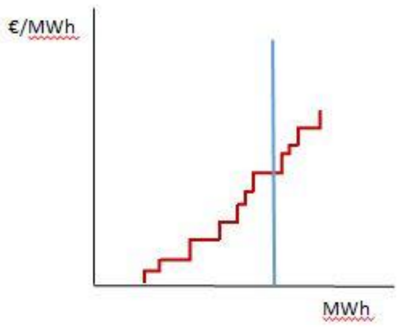

Figure 4-example of non-priced Demand Orders

Although it would be simpler for the Ukraine DAM to operate based only on Simple hourly Orders the proposal for Ukraine is to further accommodate at least Block Generating Orders (especially those of the Link and Flexible type) with a view to allowing generating units to appropriately self-schedule. Simple Hourly Generating Orders may have the format of increasing energy-price steps.

A summary description of Block Generating Orders based on the corresponding description provided by Euphemia is attached in the Annex.

Linked Block Offers are accommodated in Nord Pool and are mainly utilized to schedule generating units above technical minimum under economically efficient terms.

There are also other types of Block Offers utilized in Europe's spot markets such as Profiled Block Orders, Block Orders in an Exclusive group and Flexible Hourly Orders which could be introduced in the Ukrainian DAM.

5.7 Day Ahead Market Clearing Price

The DAM algorithm should match energy demand and supply for all the hourly periods of a single day at once.

The algorithm should return the market clearing prices per hour, the matched volumes and the selection of block and simple orders that will be executed.

By ignoring the particular requirements of the block orders, the market problem resolves into a much simpler problem, solved using commercial off-the-shelf solvers. However, the presence of block orders makes the problem more complex. The "kill-or-fill" parameter of block orders requires the introduction of binary variables which lead to a more complicated total process. In the past years, commercial solvers accommodating binary variables have been developed and therefore this should not be deemed as an obstacle.

All accepted Generating Orders are paid and all accepted Demand Orders are paying the hourly Day Ahead Market Clearing Prices.

5.8 Enforcement of liquidity within the Day Ahead market

With a view to fostering liquidity in the DAM, the draft Law foresees that the Regulator may set an obligation to all producers (except micro, mini and small hydroelectric stations and power stations producing electricity from RES) to **sell** in the DAM energy quantities, on a monthly basis, which at least equal 15% of their total energy produced (in MWh) during the month. This requirement is rather difficult to be implemented. The Regulator may impose an obligation to producers **to offer** quantities. These quantities may or may not be cleared in the DAM. It is therefore, technically difficult to impose such an obligation. Moreover, the monthly basis is too wide to provide for real liquidity on an hourly basis.

Producers' orders to the DAM shouldn't be regulated as to their price level (lower and upper limits may be set by the regulator –see paragraph 5.9 but the allowed price band should be wide). Taking into account that the Regulator shouldn't intervene in the prices offered in the DAM, it is not clear why the Regulator should impose an obligation to the injection side instead of imposing an obligation to the demand side (obligation to buy minimum quantities in the DAM) which by default would create liquidity.

The draft Law also foresees that the Regulator may set minimum quantities to be purchased by the TSO and the DSOs through DAM in respect of network losses. The Regulator may as well set the minimum quantities that hydro pumping stations should purchase from the DAM.

Based on the above, it is proposed, that the Regulator requires that all pumping needs are covered through the DAM (with the exemption of limited emergency quantities that should be allowed to be purchased in the IDM). Similarly, the TSO and DSOs should buy all transmission and distribution network losses through the DAM. The Regulator should allow them to correct positions in the IDM. Moreover, an obligation should be applied to all generation units (exempting those under contract with the Guaranteed Buyer) to offer all their residual capacity (i.e. capacity that has not been committed under reserve or bilateral contracts) in the DAM.

NEURC should always take care that enough consumption is participating in the DAM as this is the market to mainly absorb RES injection under the orders submitted in the DAM by the Guaranteed Buyer.

Creating liquidity in the DAM is crucial as the price of the DAM will be a reference price for all trading activities in the country and it is therefore essential to represent a substantial part of the trading activities. The DAM price provides the signal that is taken into account by market players when they trade to the various market segments or even when they provide for balancing services. The DAM price is also serving as the wholesale reference price used by the regulator when it comes to developing methodologies which require a benchmark price as the price everyone would pay/receive in a gross system.

5.9 Upper and lower limits of Generating Orders in the DAM

Considering NEURC envisages no payments for long term reserves under the present status, neither a separate capacity market (or capacity payments) accompany the wholesale market, the imposition of a low cap to the Generating Orders placed in the DAM could led to "missing money" problems. Generating units should be allowed to place orders that also reflect part of their fixed costs and therefore the cap should be set highly enough. The proposal is for the upper limit to be set to a price that could be calculated by the Regulator to approach the Value of Lost Load (VoLL) in the country and be furthermore in line with corresponding upper limits set in the coupled European markets. This price in European markets is currently set to 3000 €/MWh. As soon as the Ukrainian DAM is coupled with any other market corresponding caps should be harmonised.

Generating Orders in the DAM should be equal or greater than zero. For the thermal units though, the lower limit should be set to each unit's variable cost. Such an obligation is proposed to be placed with a view to avoiding damping practices and for a transitional period. As soon as Ukraine is coupled with the rest of Europe corresponding lower limit should be harmonised with the corresponding value of the rest bidding zones and the regulator will have to monitor ex-post only possible damping behaviours.

5.10 Transitional arrangements with regard to Burstyn Island

The Ukrainian system (with the exemption of the Burstyn Island) is not interconnected to the rest of ENTSO-E system. Burstyn Island operates totally isolated to the rest of Ukraine meaning that even if we approach the situation by creating one bidding zone at the Burstyn Island fully operating under the CACM NC provisions and another bidding zone for the rest of Ukraine there would be no interconnector[7] for implicit exchanges that would allow the rest of Ukraine to be coupled with the Burstyn Island.

As a transitional phase the DAM and the IDM of Ukraine will not be coupled with the corresponding markets of Europe. However, the software to be developed will be in full compliance to allow coupling in the future, at a second stage.

For a first period, our proposal is the Ukrainian DAM to run taking into account the physical constraint between the two areas. This means that the DAM algorithm will run for the two zones separately. Producers, imports and exports will phase the DAM prices as these are calculated in each zone. However, the algorithm should further calculate a single price as a reference price for the total of the Ukrainian territory. This unique price will be the wholesale price local consumption will face[8].

Creation of a DAM zone shall follow the principles of transparency and neutrality in the management of existing physical constraints and shall be in compliance with the Energy Community legislation.

At a second stage Ukraine should seek to couple with the neighbouring European markets under the most efficient and cost effective way.

Competition in the Burstyn Island is expected to emerge through cross border trades of electricity. However, as this is an area where the portfolio of generation resources is not wide, NEURC should monitor any possible abuse caused by market participants and take appropriate measures if needed to protect the liquidity and smooth operation of the DAM in this zone.

[7] as the case is with Estonia and Finland which operate under different synchronous systems but share an interconnector which allows them to couple

[8] The algorithm may go through complex iterations to weight prices and quantities in both areas and clear corresponding bids for energy absorption on a common basis for both areas (similar to the methodology for the calculation of the PUN price). The process gets much simpler in case local consumption is deemed as inelastic in both areas. In that case the algorithm clears all local demand by default and the common price is calculated as the weighted average price.

6. Intra-day arrangements

6.1 Continuous Intra Day Market

Intra-Day Markets are an essential market element in creating a well-functioning electricity market. Specifically, Intra-Day Markets allow Market Participants to update their trading position based on their risk profile taking into account evolving market and system conditions as we approach real time. The ability of Market Participants to adjust their position is also essential in integrating variable RES such as wind and solar energy into the electricity market. This allows RES to use more accurate short-term forecasts for their generation output and reduce their imbalance exposure in the real-time market.

IDM Market Participants in Ukraine will be able to continue to fine tune their positions after the gate closure of the DAM, taking into account new available information about their own production and consumption positions and also the overall market and system conditions.

The cross border continuous Intra-Day Market model that is promoted by the CACM NC and the corresponding initiatives currently undertaken by the European markets is governed by the following key principles:

- continuous trading: IDM Market Participants contract immediately the necessary intra-day energy they need or negotiate (anonymously) the price, without the need for (and risk associated to) contracting the cross border transmission capacity separately
- Transparent and non-discriminatory access to the available cross border capacity
- Trades need to be firm and irrevocable
- Speed of transaction: intra-day trading takes place in very tight time schedules
- Independency from the cross border transmission capacity determination model: it works both with ATC-based or flow-based methodologies.

Continuous trading only works with a “first-come-first-served” type of allocation method.

The IDM will run under the same rules but separately for the area of Burstyn.

6.2 Explicit cross border capacity allocation and continuous IDM

The promoted cross border intra-day model is based on a collaboration between Market Operators (or else Nominated Electricity Market Operators - NEMOs), to allow their respective intra-day Bids and Offers **to continuously match** between them, irrespectively to which Market Operator and Bidding Zone they are submitted to. This assumes that sufficient Cross Zonal Capacity is available i.e. assumes implicit capacity allocation method. The continuous matching can take place until a final gate closure before the start of the delivery (the gate closure shall be defined at the maximum one hour prior to the start of the relevant period of delivery, as prescribed in the CACM NC).

This is an issue to be discussed. The continuous IDM in Ukraine could not accommodate import/export Orders if corresponding intra-day PTRs are explicitly allocated.

6.3 The IDM process

IDM Market Participants shall participate on a portfolio basis, meaning that offers in the Intra-Day Market shall refer to the participants' net portfolio of generation-demand, without ex-ante defining the generating units that shall be involved in the sale of energy.

IDM Market Participants shall then be obliged to nominate (register) the transacted quantities, per generation unit, to the TSO, within the delivery day. IDM Market Participants shall nominate, at the latest 50 minutes before real time, the following intra-day transacted quantities:

a) the sold/bought energy quantities per generating unit for production, and

b) the sold/bought energy quantities per system zone[9] for demand.

The main reason for using a portfolio-based approach in the Ukrainian Intra-Day Market relates to the fact that such an approach is expected to give wholesale market participants more flexibility to correct their forward and/or DAM positions close to real time. The portfolio based approach for the IDM is also chosen to allow traders/wholesale suppliers to correct their positions and hedge against imbalances.

It is necessary though that the TSO checks the Intra-Day Market nominations of the transacted quantities with regard to generating units' registered quantities (a) for feasibility against the technical constraints of the generating units, and (b) for consistency with the already awarded reserve capacities.

50 minutes before real time, IDM market participants nominate to the TSO and copied to the MO the so called Final Physical Positions of the corresponding injection units and withdrawal points (meters) they represent. Traders/wholesale suppliers should nominate matching transactions i.e. their final net position should sum to zero.

In addition to the feasibility check executed by the TSO, the MO should also perform a validation check to see if the nominated energy quantity of the Market Participant is equal to the sold/bought energy quantity in the Intra-Day Market. This check precedes the check of the TSO. In case the MO check is not successful, the nomination is rejected.

The registration platform referred here for the support of the IDM nominations could be the same with the platform referred in the forward market. The registration platform shall be owned and operated by the MO. However, for some data the responsibility of validation lies with the TSO. For this reason, the registration platform should be constructed to allow the

[9]Ukraine is expected to comprise of at least two zones - ?

automatic sharing of some data with the TSO, and the automatic validation of this data by the TSO.

Due to the short timing of the processes between the Intra-Day and the Balancing Market, all nomination validations should be performed automatically by the registration platform, at the time of submission of nominations by the market participants, giving adequate justification in case of rejection of nominations. This will assist Market Participants to re-submit correctly their nominations.

Trading in the Continuous Intra-day Market in Ukraine shall take place every day until one hour before delivery (24 gate closures in each day). Note that according to the CACM NC the intra-day gate closure shall be set at the maximum one hour prior to the start of the relevant delivery period and shall respect the balancing processes related to system security.

A web-based trading system shall be provided by the MO, with the capability of combining all functionalities concerning the cross border intra-day continuous trading(visibility of offers in other bidding zones and vice versa etc.).

6.4 Orders in the IDM

A Limit Order in the Intra-Day Market is a buy or sell Order which carries a price limit and can be matched at this price limit or better, for as much of the Order volume as possible. More specifically, a Limit Order shall be an Order, to sell or buy, at a minimum selling price or a maximum purchase price. If not fully matched, it shall be stored in the Order Book in descending buy-price order or ascending sell-price order, and join the queue of Orders having the same price according to time priority. If the price specified for the Limit Order is not valid according to the allowed sizes, it shall be rejected.

If an incoming Limit Order can be executed with a Limit Order already stored in the Order Book, a transaction shall be effected at the price of the Order contained in the Order Book.

Anonymous orders by market participants shall be matched based on a “first-come-first-served” principle where lowest sell price and highest buy price comes first, regardless of when an order is placed (“price priority”). Only in the event that prices are identical, orders shall be matched in the order in which they were entered into the trading platform (“time priority”).

Within the IDM the following types of Orders can be traded:

- Hourly Orders: these combine a price and a volume and may refer to each of the 24 delivery hours of the delivery day D
- Block Orders: these combine several hourly Orders, with at least two consecutive hours of the delivery day, which depend on each other execution. They can be defined by market participants who decide which hours to link, or can be pre-defined. In the latter case the IDM should at least accommodate base load block, covering all 24 delivery hours of any delivery day of a week and peak load block covering all 13 delivery hours

from 08:00 (am) to 21:00 (pm) of a delivery day, for all week days apart from weekends.

The nominations shall refer to the whole delivery period which concerns each intra-day transaction (hour, block of hours).

Starting at 15:00 (pm) on day D-1, IDM market participants shall be able to submit their Orders with respect to all delivery periods of the following delivery day. The submission of the Orders shall continue during the delivery day D.

In any case, the Orders shall be submitted until 60 minutes before delivery begins (the gate closure of each delivery period is 60 minutes before the delivery period commences). The gate closure applies both to the proposed hourly Orders and block Orders.

Orders and transactions in the IDM trading system shall be performed in an anonymous manner and should contain at least the following information: Identity of the IDM market participant, Identification codes related to the form of the Order (hourly or block), whether the Order is a Bid or an Offer, the Order Type, the Order quantity and price (in Euro/MWh), possible execution specifications (all or none, fill or kill etc.).

The functionality of the trading system shall automatically validate the above mentioned information for all Orders registered, and store Orders in an electronic Order Book, in case these Orders, according to their execution specifications, were not executed.

It should be noted that all Orders submitted in the IDM trading system shall always be priced Orders.

To participate in the IDM, the corresponding participant should have made transaction for the same delivery hour either through bilateral contracts or through the DAM or both. .

6.5 IDM Interface with the DAM

The Physical Position of each generating unit, namely the energy schedule resulting from the Day-Ahead Market solution shall be used in conjunction with the intra-day traded energy quantities (intra-day nominations) to formulate the Final Physical Positions of generating units and offtake points. The energy schedule “coming” from the Day-Ahead Market for each generating unit, includes also the Forward OTC quantities, which have been traded in the forward market, allocated (declared) at the registration platform (by 09:00 D-1) by market participants and inserted as “must-run” quantities in the DAM (quantities with priority in market clearing) by the MO on behalf of respective market participants.

It is clarified that if no nomination in the IDM platform is performed until 50 minutes before real time by wholesale market participants then the previous Physical Positions, as calculated right after the DAM clearance, will apply.

6.6 IDM Interface with the BM

After the results of the IDM are distributed to IDM participants, corresponding participants will have to physically register per unit, displaceable load and offtake account, final traded quantities in the form of Final Physical Positions for the next hour.

In parallel, BSPs have to submit to the TSO updated detailed generation (or load) schedules indicating their capacity on a [5] minutes basis for the next hour. These schedules should give the same energy quantities as the hourly Final Physical Positions submitted by corresponding market participants. Final Imports/Exports Nominations by market participants shall also by submitted in this stage.

Following the physical quantities registration in the software platform of the TSO the Balance Responsible Party (BRP) of each market participant should be notified automatically by the software platform of the Final Physical Positions of the market participants it represents.

This data will be also passed to the TSO platform where the corresponding BRPs' Net Positions will be calculated. It is clarified that BRPs' Net Position can be either positive (net injection of energy) or negative (net withdrawal of energy) or balanced.

The TSO runs its balancing process by respecting the physical scheduling of market participants as this comes out of their participation in the forward, day ahead and intra-day markets.

In case the real time balancing algorithm does not resolve upwards and downwards energy requirements solely based on an hourly window but also takes into account a period of consecutive hours then the dispatching orders coming out of this real time balancing mechanism should be bidding for corresponding BSPs meaning they will not be able to trade in the IDM quantities instructed by the real time balancing for next hours. This will require appropriate interface between the BM and the IDM to allow for correct validation of IDM offers.

7. Real Time Balancing

7.1 The Balancing Process

As earlier described, the Final Physical Positions of generating units comprising of their validated Physical Delivery Nomination and the DAM and IDM scheduled volumes provide for a self-scheduling program.

The TSO should run a process of matching in real time system load (as this is forecasted by the TSO taking into account all update information in the system) with available generation resources, known as system balancing. In doing so the TSO should develop a Balancing Market (BM) where corresponding resources may place their bids and offers for balancing services and be selected by the TSO.

Under the ACER FG EB "The Network Code on Electricity Balancing shall allow BSPs to place and or update their bids as close to real time as possible and at least up to one hour before real time" therefore, the hourly balancing market gate closure will be set 45 minutes prior to real hour.

The proposal is for Bids and Offers in the Balancing Market (BM) to be placed by Balancing Service Providers, per unit in case of producers. Up to 30' prior to real time the TSO should appropriately instruct increments and decrements to match generation with demand, based on the submitted bids and offers. Within Annex B we provide for a summary table of the indicative timing for the various actions made in the frame of the OTC, DAM, IDM and balancing trading. It is clarified that corresponding timings will be finally determined within the detailed Market Rules, DAM and IDM Rules.

Participation in the BM is mandatory for all thermal power units with installed capacity above [X] MW and dispatchable Hydro units for the capacity that has not been committed under reserve contracts, OTC contracts, the DAM and the IDM. Participation for nuclear power plants is also mandatory under corresponding technical (ramp rates) and safety standards.

The Balancing Market shall run and produce dispatching instructions for every 60 min of day D (i.e. the BM program time unit equals the Imbalance Settlement period[10]). The 60' minutes is set as an initial balancing program time unit however we underline that in a few years it might be more efficient to set this time unit to 30' or even 15'.

The BM should run an optimization function to activate balancing energy based on submitted costs through a non -discriminatory, fair, objective and transparent mechanism which

[10] According to ACER FG on EB, the balancing program time unit should be consistent with the imbalances settlement period. Our proposal is to set both equal to 60'.

minimizes the costs of balancing whilst takes into account technical (e.g. synchronization, minimum up, minimum, down ramp up and ramp down times etc.) and network constraints.

Ranking of offers is made from the lowest priced to the highest priced whilst ranking of bids is made from the highest (in absolute terms) to the lowest priced.

As per the EB NC of ENTSO-E, in case the activation of balancing energy for balancing purposes deviates from the merit order then the TSO should report the incident.

It is clarified that Bids and Offers in the Balancing Market are submitted to the TSO.

Any network outages and constraints[11] should be managed through the balancing process.

7.2 Balancing Energy and Reserves Capacity

Balancing Energy consists of both energy activated in real time under operating reserves contracts and energy provided directly to the Balancing Market by all other available resources.

“Balancing energy” is distinguished from “reserves capacity” based on the following principles:

- Ahead of real time (i.e. before the gate closure time of the last market in which participants can trade energy), the TSOs secure access to power generation capacity for control purposes. In its position paper on cross border balancing[12] ENTSO- E refers to this power generation capacity (in MW) as “reserves”. In the past the most common means of securing access to these reserves were ex-ante contracts for Reserves[13].
- Close to and in real time, energy is activated either from pre-contracted reserves or other available resources in order to maintain the balance between demand and supply. This delivered energy (in MWh) is referred to as “Balancing Energy”.

7.3 Balancing Service Providers

During the first phase of the market operation, only thermal, nuclear and dispatchable hydro generating units and dispatchable load provide balancing services, referring both to reserves capacity and balancing energy.

At a second phase RES plants operating outside green tariffs holding appropriate technical capabilities should also be allowed to provide balancing energy as BSPs in view of adapting to

[11] It is clarified that the Burstyn island case is not considered as a simple network constraint and it is therefore handled differently.

[12] *Position Paper on Cross-Border Balancing*, ENTSO-E, July 2011.

[13] We note however, that market based mechanisms closer to or in to real time have meantime been developed in other jurisdictions (e.g. UK, Italy, and elsewhere) as a means of accessing reserves without creating market distortions.

ACER's FG which require generation units from renewable and intermittent energy sources to become BSPs.

Balancing energy is offered by Balancing Services Providers (BSPs) in the form of Bids for energy absorption from the system or Offers for energy injection into the system[14].

The BM process will produce bids and offers acceptance which will be transposed to dispatch instructions issued by the TSO. Bids and offers acceptance entails corresponding obligations for the balancing services providers.

7.4 Bids and Offers placed by generating units to increase or decrease generation

The format of the Offers submitted to the balancing market should at least foresee for differentiated prices between the following two cases:

a) generation increase from zero production level up to technical minimum

b) generation increase from technical minimum up to the maximum seasonal generation level.

The format of the Bids submitted to the balancing market should at least foresee for differentiated prices between the following two cases:

a) generation decrease from maximum generation level down to the technical minimum

b) generation decrease from technical minimum to zero (shutting down).

The design should allow negative priced bids in the Balancing Market especially with regard to future RES participation as BSPs (RES under bilateral contracts who are paid on metered quantities should be allowed to place negative bids in the BM in exchange of their lost income). RES aggregators, at a later stage, should also be allowed to offer balancing energy from a group of RES plants which should be treated as one "virtual" plant.

Offers shall be ranked in non-decreasing price order from the lowest-priced offers to the highest-priced ones. Bids shall be ranked in non-increasing price order from the higher to the lowest-priced ones.

[14]In market environments, bid prices are usually close to corresponding variable costs of the parties providing the services, since such units are already scheduled at the contracted level and thus fixed costs are already covered. Therefore, such units are willing to pay any price below their variable cost to reduce generation, a practice which creates extra profit for them. On the other hand, offer prices are usually based on the spot market price plus a premium reflecting missed revenues by not selling in the spot market.

7.5 Bids and Offers placed by dispatchable load to increase or decrease demand

Dispatchable load may place offers to decrease consumption i.e. to sell energy to the system. Corresponding offers will be taken into account in determining the imbalance price. Accepted offers for demand decrease are paid to suppliers/end customers by the TSO. Similarly, dispatchable load may place bids to increase consumption i.e. to purchase energy from the system. Corresponding bids will be taken into account in determining the imbalance price. Accepted bids for demand increase are paid to the TSO by suppliers/end customers. For simplification purposes during the first phase of the market operation single price-quantity pairs for each hourly period are suggested to be placed for demand increases/decreases.

This arrangement will be initially feasible for large consumers with appropriate technical characteristics which could provide balancing services. However, as described under Section 13 Demand Response activated through Demand Response Agents should also be possible in a later phase, through offers for demand curtailments.

7.6 Payment of accepted bids and offers

Theoretically, if participants in the balancing market had an accurate view of how demand and supply would evolve every hour of the next day, the results between the two alternatives (pay as bid or pay as cleared) would be equivalent. If, under the pay as bid approach, producers could accurately predict the each time marginal unit, they would submit offers priced at the cost of the marginal with a view to maximizing their revenues i.e., the expense for the system would be the same in both cases. However, because there can be no forecasting accuracy, under the pay as bid approach inefficiencies in the way offers are priced are created, leading to inefficiencies in the way offers are selected.

Marginal payment is considered to lead to fewer distortions, as it motivates producers to offer very close to their marginal costs knowing that if another more expensive offer is accepted they will be paid the expensive price. Therefore, offers under a pay as cleared approach are based on actual costs rather on participants' estimates of how balancing will evolve and which units will be used. Moreover, when marginal pricing is applied, participation in the balancing market becomes simpler for participants; especially for new entrants who have gained no market experience that would allow them to maximize their revenues through appropriately priced offers' submission, as the case is in "pay as bid" markets. Therefore the marginal pricing approach is proposed.

Depending on whether the system is short or long, the most expensive offer or the cheapest bid will set the imbalance price.

Specifically, when the system is in deficit (short) the TSO is expected to accept offers for generation increase or for demand decrease. Offers accepted under the balancing mechanism are paid the marginal price i.e. are paid the most expensive price accepted during the corresponding settlement period for selling energy to the system. This price comprises also the imbalance price to be applied to those parties found out of balance.

When the system is in excess (long) the TSO is expected to accept bids for generation decrease or demand increase. Bids accepted under the balancing market are paying the marginal price i.e. are paying the “cheapest”[15] price accepted during the corresponding settlement period for purchasing energy from the system. This price comprises also the imbalance price to be applied to those parties found out of balance.

For those cases when the system is short but the TSO must enable generation decrease or demand increase through bids acceptance, these are paid the price of the last accepted bid. Respectively, when the system is long and the TSO must accept offers for production increase or demand decrease corresponding offers will be paid the most expensive offer accepted. Bids and Offers accepted for system constraints management should be tagged and excluded from the imbalance price calculation.

7.7 Upper limit of the offers submitted in the balancing market

The value of the energy offered under the balancing market should not exceed the VoLL (Value of Lost Load). However, usually the regulators need a substantially lower cap to be set with view to avoiding sudden and sharp price increases.

Considering that participation in the balancing market is obligatory, setting the BM cap at a lower level than that of the DAM cap, may create distortions.

We note that, in accordance with the draft Law, in an emergency situation of the electricity market the operation of the wholesale market may be suspended according to the market rules.

[15] Among bids the higher in absolute value is selected first. Then the second higher and so on. But all accepted are paying the TSO the lowest accepted bid.

8. Operating Reserves and Other Ancillary Services

8.1 Reserves procurement principles

Markets for reserves are (or were) in some European States "capacity and energy" markets, sometime also described as "reservation and utilisation", i.e. capacity availability and energy are remunerated separately. Under such schemes the TSO is pre-contracting and paying for the availability of reserves, while energy is remunerated upon utilization in real time.

Pricing of availability of reserves is usually based on fixed costs and can either reflect actual fixed costs of those specific units providing the services, or be based on the "Best New Entrant" (BNE) approach or can be regulated.

Under the regulation approach, recovery of reasonable fixed costs including an allowance for a reasonable rate of return on the assets being reserved i.e. a profit, should be provided. Unless some allowance is made for a profit element, there is no incentive for market participants to invest in additional capacity.

There are two options for setting the prices for energy utilisation: either "lock" the energy price at the time the contract is agreed or allow it to "float" depending on actual market conditions.

Based on the principle of avoiding reserves procurement under terms that distort the market and create barriers to entry for new players, the proposal is to avoid long–term commitments for reserves procurement. This is also suggested by the ACER FG which clearly dictates that TSOs should procure as many reserves as possible in the short term, by limiting the duration of reserve contracts so that it facilitates participation of new entrants, demand response and renewable producers as well as small producers.

In principle the imbalance price should reflect the full cost of balancing. Consideration has been given on how the reservation cost could be taken into account to allow the TSO to make a choice for balancing energy between contracted and non-contracted BSPs. To that end weighting the utilization price by some portion of the reservation cost has been examined.

Although such an approach leads to an imbalance price which reveals the true costs of balancing, it might lead to sub-optimal results as the BM may choose a non- contracted BSP to provide balancing energy because its total cost as revealed in its offer was lower than the corresponding total cost of a contracted BSP (as this cost is finally entering the algorithm through the weighting process above described). However, this might not prove the optimal choice if the reservation fee of the contracted BSP is also counted, since this will be paid in any case. Therefore, it is acceptable for the contracted BSPs to be in a more competitive position than the non-contracted BSPs for that part which corresponds to the reserved capacity. Based on the above observation, no reservation fees weighting process is proposed.

8.2 Types of Operating Reserves

Under the Load Frequency Control and Reserves Network Code (LFCR NC)the following type of operating reserves are defined:

- Frequency Containment Reserves(FCR) means the reserve utilized by a process that aims at stabilizing the System Frequency.
- Frequency Restoration Reserves (FRR) means the Active Power Reserves activated to restore System Frequency to the Nominal Frequency and for Synchronous Area consisting of more than one LFC Area power balance to the scheduled value.
- Replacement Reserves (RR) means the reserves used to restore/support the required level of FRR to be prepared for additional system imbalances. This category includes operating reserves with activation time from Time to Restore Frequency up to hours.

The draft Transmission Electricity Network Code defines three types ofoperational reserves: the primary, secondary and tertiary control. It is proposed that the final Transmission Electricity Network Code harmonises with ENTSO-E terminology. Under ENTSO-E the FRR can be distinguished in two categories the aFRR (automated FRR) and the mFRR (manual FRR). The second seems to correspond to the fast tertiary reserve as this is by determined by the draft Transmission Electricity Network Code. The slow tertiary corresponds to the RR.

8.3 Procurement of Operating Reserves

Under the EB NC, Balancing Services Providers may provide the above operating reserves to the TSO under the following principles:

- The price for the activation of FCR, FRR and RR volumes should be defined for each direction, for each imbalance settlement period and for each imbalance area.
- The TSO should utilise a market based method for the procurement of at least FRR and RR reserves
- Contracts for Balancing (Reserves) Capacity should not exceed one month.
- Procurement of upward and downward capacity for FRR and RR should be performed separately (they could be linked only following NEURC's approval). For FCR upwards and downwards, procurement may be combined.

According to the draft Transmission Electricity Network Code all power plant units, as well as rotating generating sets of all other electricity producers shall be equipped with systems for turbine speed control and be engaged in primary frequency control.

If this requirement is set by the Transmission Electricity Network Code it means that corresponding investments will be mandated by the Code on a non –discriminatory basis and then FCR could be procured as an obligatory reserve service (non-paid or paid under regulated prices) to those generating units that hold corresponding capabilities[16]. In case of non-paid FCR corresponding costs are born by the owners of the generating units and passed to the commercial prices these units are offering to the various market segments. In case however there is a substantial deficit of this type of reserve and significant investment is needed then a tendering process could be also organised for this type of reserve too. In case the tendering process is the choice of the Regulator corresponding obligation should cease to exist in the Transmission Electricity Network Code.

It is further proposed that Frequency Restoration Reserve (FRR) (upwards and downwards) as well as Replacement Reserve (RR)(upwards and downwards) are offered through monthly contracts which will remunerate the corresponding availability reservation per direction. The monthly period is proposed to allow new entrants more flexibility in deciding, closer to real time, whether to bid or not for corresponding services. If the reserve contracts are assigned on an annual basis it might be proved that only those holding a portfolio of units will take advantage of it.

The tendering option is the simplest and the more market based solution. The cheapest offers will be selected until the requirement of the TSO is met. Providers are paid their bids[17]. The TSO should organise a tendering process tailored to the needs of the system. NEURC should approve the tendering terms following a proposal by the TSO. It is proposed that FCR and aFRR are procured on a unit basis. mFRR and RR could be procured on a participant basis however by 18:00 on D-2, participants should inform the TSO of the exact generating ubits offering each type of contracted reserve. Corresponding information should be then passed to the MO. It is noted that NEURC may for a transitional period impose an obligation to all thermal and dispatchable hydro units, above a threshold, to submit offers to the operating reserves tendering process.

There are two options for FRR and RR reservation cost allocation: either it is passed to all suppliers proportionally to consumption or is levied to all BRPs proportionally to the imbalances they have registered on an hourly basis I.e. the reservation cost is distributed to each hour of the month (through appropriate coefficients application with a view to charging more those hours during which the system is in stress) and then levied for each hour of the month to corresponding imbalanced parties on a proportional basis[18]. The first approach is proposed as it is more simple and straightforward for an immature market.

The activation of FCR, FRR and RR will take place through the balancing market. Bids and Offers for balancing energy corresponding to ex-ante contracted FCR, FRR and RR capacity, if accepted will receive the marginal price. Activation will be effected based the cheaper offers available meeting though the each time required activation times. Considering that the units

[16]As the case is in Spain

[17] Marginal pricing is also an option however considering that the draft Law allows the regulator to set the prices in cases participants exercising market power, pay as bid is inevitable

[18]Iin cases of settlement periods for which no imbalances are registered, the coefficient could be such that corresponding costs are not allocated to these periods.

offering corresponding services will be paid their fixed costs (reservation fee) independently of whether activated or not, corresponding bids and offers in a competitive market are expected to reflect the short-run costs of the generating units.

The reservation fee for FCR (if any) FRR, and RR procurement will be ex-post collected by the TSO as previously described (i.e. paid by all consumers on a proportional basis) and shall be paid to corresponding providers within the following month (the TSO should apply a rule to penalize cases of units non-availability in relation to the contracted reserves capacity).

No payments for long-term reserve are envisaged under NEURC.

NEURC in cooperation with the TSO, should periodically consider if the existing capacity is sufficient to cover operating reserves requirements. In the event that above requirements are not met, NEURC should allow the TSO to ex-ante contract generation capacity.

Reservation costs are allocated to consumption.

Demand side could also participate to the ex-ante operating reserves tenders, provided it holds appropriate technical capabilities to meet activation times set by the TSO under each type of procured reserve.

The TSO by 8:00 on D-1 sends to the MO OTC registration platform data regarding reserves commitment by the various generation units.

The Regulator should have the right to regulate prices in case one of above mentioned operating reserves is monopolized (dominated) by one provider in either of the two zones. The methodology for setting the regulated price in such cases should be in advance approved and published. If through monitoring it is identified that there is a permanent issue of competition in providing a specific type of reserve, the Regulator may design a mechanism that will allow new providers to invest and assess an appropriate contracting period that will allow them the investment taking care to avoid state aid issues and securing economic efficiency is added through this process.

8.4 Other Ancillary Services

Other Ancillary Services, apart from Operating Reserves, which the TSO should procure from market participants to safely operate the system, such as black start and reactive power control should not be part of the BM arrangements but procured separately and charged to the total of the system customers.

9. Imbalance Settlements

9.1 Imbalance Volume Exposure

Imbalances are charged to BRPs with regard to whether they have fulfilled their commitments towards the market or had to buy (or sell) additional quantities.

The actually metered quantities of the market participants under a BRP are checked towards the declared Net Position of their BRP. The difference is deemed to be purchased or sold from/ to the system and is therefore charged or credited accordingly, at the imbalance price. Quantities corresponding to accepted bids/offers in the BM by BSPs belonging in the BRP are considered as contractual obligations and therefore are not counted as imbalances[19].

For each BRP, the difference between the net measured quantities of the market participants it represents is compared with the corresponding Net Position of the BRP, as this has been determined and notified to the TSO through the IDM process. The TSO taking also into account any accepted bids and offers in the BM (which are not counted as imbalance volumes) calculates the difference which comprises the imbalance volume of the hour.

9.2 Imbalance Price

Imbalance prices will be calculated depending on whether the system is short or long. The most expensive offer or the cheapest bid will set the imbalance price respectively.

Specifically, when the system is in deficit (short) the TSO is expected to accept offers for generation increase or for demand decrease. The most expensive offer accepted during the corresponding hourly period for selling energy to the system (marginal price) sets the imbalance price of the corresponding hour.

When the system is in excess (long) the TSO is expected to accept bids for generation decrease or demand increase. The "cheapest"[20] bid accepted during the corresponding hourly period for purchasing energy from the system sets the imbalance price of the corresponding hour.

In case there is a settlement period for which no bids or offers were accepted in the balancing market (or those accepted were all tagged as addressing system constraints) the imbalance price of this period will be calculated based on the average price either of the previous (z) working days in case the settlement period comprises a time unit within a working day or the (t) weekend days in case the settlement period comprises a time unit within a weekend day.

[19] Apart from FCR activated energy quantities which for practical reasons might be considered as imbalance quantities

[20] Among bids the higher in absolute value is selected first. Then the second higher and so on. But all accepted are paying the TSO the lowest accepted bid.

9.3 Imbalance Charges

Imbalance charges are calculated based on the single pricing settlements approach. Meaning each BRP which registers imbalance volumes pays when is short of energy (independently of the system direction) or is paid when is spilling energy (independently of the system direction).
Alternative options to the above proposed single pricing approach have been examined:

Under the dual pricing approach two imbalance prices (the marginal of offers and the marginal of bids) are calculated when the system is short and similarly two prices are calculated when the system is long. The marginal of offers is paid by those BRPs being short(both when the system is long or short) while the marginal of bids is received from those spilling (both when the system is long or short).This is a rather complicated process which is not proposed for the Ukrainian system at least for an initial period.

The approach of imbalance parties not being penalised in case they are contributing in balancing the system (i.e. their status is opposite to the system one) requires that all market participants have the same possibility of projecting the system status (or even influencing it by withholding capacity) which definitely is not the case in the Ukraine market.

The hybrid, two-prices, settlement has been also examined. This is similar to the dual pricing however, the one of the two prices applied is the DAM clearing price. This option has been rejected for similar to dual pricing reasons.

Single pricing, apart from being the simplest, leads to the lowest actual imbalance costs, therefore this mechanism results in highest efficiency in cost allocation. This mechanism allows BRPs to make a profit from being in the "right direction" and it is not unnecessarily penalising participants. Another advantage of single pricing is that it does not discriminate against small players, because the relatively higher imbalances of small BRPs are offset by the profits of being in the right direction, which can happen more often for small BRPs A concern though could be possible weak incentives to balance. In the future, in case high system imbalance problems are observed, the regulator may examine and apply other options that provide stronger balancing incentives therefore corresponding software should be capable of accommodating dual pricing (or two-prices) as well.

To avoid spilling practices or systematic under or over nominations the market rules should foresee for an administrative penalty when systematic over or under nominations are spotted in the forward, DAM or IDM stage. The penalty should be applied in a way that over or under nominations are not netted out.

The tables below present the above alternatives:

Single pricing

		System Imbalance		
		Negative (Short)	Zero	Positive (Long)
BRP Imbalance	Negative (Short)	+ IP_h	+ P_A	+ IP_l
	Zero	-	-	-
	Positive (Long)	- IP_h	- P_A	- IP_l

"+": BRP pays TSO, "-": TSO pays BRP

Dual pricing

		System Imbalance		
		Negative (Short)	Zero	Positive (Long)
BRP Imbalance	Negative (Short)	+ IP_h	+ P_A	+ IP_h
	Zero	-	-	-
	Positive (Long)	- IP_l	-P_A	- IP_l

"+": BRP pays TSO, "-": TSO pays BRP

Contributing to system balancing (opposite direction reward) pricing

		System Imbalance		
		Negative (Short)	Zero	Positive (Long)
BRP Imbalance	Negative (Short)	+ IP_h	+ P_A	- IP_l
	Zero	-	-	-
	Positive (Long)	- IP_h	- P_A	+ IP_l

"+": BRP pays TSO, "-": TSO pays BRP

Two-price pricing

		System Imbalance		
		Negative (Short)	Zero	Positive (Long)
P Im bal	Negative (Short)	+ IP_h	+ P_A	+ P_A

	Zero	-	-	-
	Positive (Long)	- P_A	- P_A	- IP_l

"+": BRP pays TSO, "-": TSO pays BRP

IPh= the marginal price of all accepted offers

IPl= the marginal price of all accepted bids

PA= a price set administratively (most probably the DAM price)

In other markets where "pay as bid" is applied, an adjustment is applied towards non-delivery of accepted bids and offers (non-delivery rule) for balancing units. The settlement is carried at a price equal to the difference between the imbalance price and the price paid to the successful bidder. The aim is to create a disincentive for producers to offer high prices to increase generation and eventually generate less than the accepted offer, knowing that they will be paid the high accepted offer price and pay back only the imbalance price which is an average price. Such a non-delivery rule is not required once the approach of marginal pricing is adopted.

9.4 Balance Responsible Parties

Balance Responsible Parties (BRPs) could be formulated under the proposed design (apart from the Guaranteed Buyer which by default undertakes the role of BRP) to undertake the financial responsibility towards the TSO for the imbalances of the market participants they represent.

Generally there are two options for the arrangements applied for BRPs: either the volumes are netted or the cash flows are netted. Since a single imbalance price is proposed the above two options provide for an equivalent result.

For the Ukrainian market it is proposed that BRPs are capable of undertaking responsibility over the netted volumes of their group (sum of all physical positions towards the sum of all metered quantities) and therefore the software to be implemented should allow for such a possibility.

Obviously the BRP will have to economically settle with its members but this will be done outside the market.

It is clarified that the BRPs undertake imbalance settlements. Payments/charges for reserves and balancing energy are made directly with BSPs.

9.5 Management of Imbalance Settlement

The BM platform operated by the TSO notifies the results of each hourly period with regard to accepted bids and offers volumes and the each time imbalance price. Three working days following the end of each month the TSO and DSO forward the certified metering data, including consumption data for those suppliers serving customers with non-interval meters with respect to the hourly periods of the previous month.

The TSO, taking into account the OTC registered quantities, the DAM and IDM scheduled quantities the BM data and the metering data performs the cash flows calculation and invoicing as per paragraph 11.7.

Although the single pricing for imbalances settlement is proposed, this does not lead to the TSO being 100% financially neutral towards market participants. This is a situation occurring because the balancing services activated in the opposite direction (than the system's one) are paid (or paying) the marginal price of their direction whereas the rest of the market pays (or is paid) the marginal of the main direction. Therefore, surpluses or deficits at the TSO account are created for each settlement period which has been set to 60'.

The proposal is that the surplus or the deficit of each hour are gathered and netted at the end of each month and proportionally returned or charged (depending on whether surplus or deficit) to all suppliers on a proportional basis (uplift).

The above mechanism bears the disadvantage of not providing for the appropriate signals to those creating the most imbalance however, it is the most transparent and simple one and it is therefore proposed at least for an initial period as we expect that these surpluses/deficits will be rather minor. Sophisticated formulas that spot the "right" and "wrong" behaviours of market participants and reward or penalize them accordingly are deemed as necessary in case the regulator, following monitoring, identifies that there is a considerable amount of surpluses/deficits socialised each month. In that case the regulator should utilise this amount to create the right signals by placing charges (or payments) to those creating the deficit/surplus

10. Management of RES and CHP energy

10.1 The Guaranteed Buyer concept for RES management

Under the draft Law the concept of the Guaranteed Buyer is introduced regarding RES treatment at the wholesale market.

The Guaranteed Buyer (GB) is obliged to buy all the net energy injected by business entities for which the "green" tariff is set, including surcharge to it, for the duration of application of the "green" tariff.

For each month, the net volume of injected electricity by renewable energy sources plants (and when using hydropower - only micro-, mini- and small hydropower plants) shall be determined by the corresponding monthly produced quantities as metered less the volume of electricity consumption for own needs in electricity of the relevant electric power facilities.

Purchase and sale of such electricity at "green" tariff, including surcharge to it, is based on the bilateral contract between the producer, for which the "green" tariff was set and the Guaranteed Buyer. Such agreement is based on a model contract for the sale of electricity at "green" tariff for the duration of the "green" tariff application as set for the producer. Standard form of contract for electricity sale at "green" tariff shall be approved by the Regulator.

The GB shall pay for electricity purchased from producers at the "green" tariff for the actual amount of electricity released at the power plants operating under the green tariff on the basis of metering data obtained from the metering administrator, in a manner and under terms determined by relevant agreements less any own consumed quantities.

To ensure coverage of economically justified costs of the GB to perform special obligations for the purchase of electricity at "green" tariff, the Cabinet of Ministers of Ukraine shall impose on the transmission system operator a special obligation to make a compensation payment to the guaranteed buyer.

[The highlighted area should be checked against the final law provisions].

The GB shall be the party responsible for balancing of the balance group of "green" tariff producers, with which it has concluded the bilateral contracts.

It is further entitled to obtain from producers, from which it purchases electricity at "green" tariff, their daily schedules of electricity delivery in the manner and form specified by relevant contracts.

The draft Law foresees that “The guaranteed buyer shall be entitled to receive compensation payments corresponding to the expenses incurred as a result of the difference between the prices of electricity purchased under “green” tariff and the electricity market price. This difference and the corresponding amount needed for compensation shall be calculated on the basis of a methodology determined by the Regulator upon consultation with the Energy Community Secretariat.

The above provision of the draft Law makes the GB financial responsible over the RES energy quantities it resells under bilateral contracts and the IDM in comparison to the DAM price. The GB will be compensated the difference with the DAM price for the total metered quantities compared to the green tariff applied for these quantities.

According to the draft Law the settlement of the imbalances for corresponding quantities should be also taken into account for the compensation calculation. It is clarified thought that until 2025a progressively reduced part of this cost will be taken into account into the compensation calculation. From 2025 onwards the RES plants under green tariffs will have to face the total of the net cost/profit of the GB regarding imbalances settlement.

The GB submits RES quantities in the DAM stage without a price however, when it comes to the IDM, quantities should be offered under a price. Our approach is that the GB should be allowed not only to sell any excess quantities in the IDM but also buy energy to hedge against imbalance cost. To this end it is proposed that the GB is left free to trade within the IDM and decide upon the offered or accepted prices according to professional standards (under ex-post monitoring by NEURC) and the total of its exposure to the IDM i.e. corresponding profit or loss compared to the DAM price is born by the GB.

10.2 The Guaranteed Buyer concept for CHP management

According to the draft Law, the Cabinet of Ministers of Ukraine imposes a special duty on the GB for purchase of electricity generated by the cogeneration power plants in amounts not exceeding the amounts calculated in determining the regulated price of purchase, at the regulated price.

To ensure coverage of economic and reasonable expenses of the GB to perform special duties for the purchase of electricity generated by cogeneration power plants at the regulated price, the Cabinet of Ministers of Ukraine imposes a special obligation on the transmission system operator to pay the compensation payment to the GB.

[The highlighted area should be checked against the final law provisions].

Compensation payments should provide coverage to the guaranteed buyer for the difference between the cost of electricity purchased by him at the regulated purchase price and the cost of electricity sold at prices of the "day ahead" market.

Compensation payments are calculated by the GB under the procedure of purchase of electricity of cogeneration power plants at regulated prices. The amount of the compensation payment is approved by the Regulator.

The above provision of the draft Law makes the GB financial responsible over the CHP energy quantities it resells under bilateral contracts and the IDM in comparison to the DAM price. The GB will be compensated the difference with the DAM price for the total metered quantities compared to the regulated tariff applied for these quantities.

The GB submits CHP quantities in the DAM stage without a price however, when it comes to the IDM, quantities should be offered under a price. The GB should be allowed to buy energy to hedge against imbalance cost of CHP in case the GB is notified by the CHP power plant owner that will generate less than initially scheduled (and also sell any excess quantities in the IDM in case it is informed that a CHP power plant will generate more than initially scheduled). To this end it is proposed that the GB is offering a price to the IDM as agreed with the CHP owners. CHP owners will be charged for the IDM cost (or compensated in case of IDM income) accordingly. CHP owners will be further charged by the TSO for their imbalances on the basis of the nominated quantities., on a per unit basis..

The draft Law doesn't foresee that the GB should, by default, be the BRP of the CHP power plants from which it purchases electricity at regulated prices. It is therefore proposed that CHP plants undertake balance responsibility towards the TSO directly and not through the GB.

It is important to mention that the GB should keep separate accounts with regard to RES and CHP management.

10.3 The GB processes regarding RES

The GB should submit a cumulative forecast for the total of the RES energy under green tariffs and pay imbalances based on the total metered quantities of the RES plants it represents. This means that the GB, for imbalance settlement purposes, will hold one RES generation account with multiple RES injection metering points registered within it.

The GB should be allowed to purchase, develop and run a tool for RES production forecast. The GB should submit cumulative non priced offers in the DAM based on its own forecasts. The same applies for the updated quantities traded in the IDM.

However, as above stated, RES power plants under green tariffs are obliged to provide the GB on a daily basis their production schedules (forecasts).

The deviation of actual volumes of supply of electricity of 'green tariff' producers from their daily schedules of electricity delivery for the next day shall be considered as imbalances of the "green" tariff producer.

Based on these differences the GB will calculate the coefficients (on an hourly basis) which should be applied to allocate the net cost/profit of the GB's IDM activation and imbalances settlement.

It is further clarified that according to the Law provisions the reimbursement rate for producers that produce electricity at electricity facilities using the energy of wind and sun light, for which the green tariff is set and which are within the balancing group of green tariff producers is as follows:

Until December 31, 2019 року — 0 %;

From January 1, 2020 року — 10 %;

From January 1, 2021 року — 20 %;

From January 1, 2022 року — 40 %;

From January 1, 2023 року — 60 %;

From January 1, 2024 року — 80 %;

From January 1, 2025 року — 100 %.

Until 2025, the reimbursement of imbalance by producers that produce electricity at electricity facilities using the energy of wind and take part in balancing group under the "green tariff", is committed to the Guaranteed Buyer in case of deviation of its ex post amount of produced electricity from its daily production schedule more than 10%.

Until 2025, the reimbursement of imbalance by producers that produce electricity at electricity facilities using the solar energy and take part in balancing group under the "green tariff", is committed to the Guaranteed Buyer in case of deviation of its ex post amount of produced electricity from its daily production schedule more than 5%.

[The highlighted area should be checked against the final law provisions].

As above stated the GB shall be the BRP of all RES power plants under green tariffs. However in case a RES power plant under green tariff (which has a bilateral contract with the GB) disputes over the accuracy of the forecasts provided by the GB or/and its professional decisions regarding IDM trading, then this RES plant shall pay imbalance cost on an individual basis, outside the cumulative allocation process. Specifically, in such a case the RES plant will be charged/credited the each time imbalance price for the imbalanced volume calculated as the difference between its own forecast(as submitted to the GB) and the metered quantities. Obviously in such cases they will not be able to benefit from the IDM.

10.4 RES power plants without support schemes

RES plants outside the "green tariff" support scheme may either contract on a bilateral basis at the forward stage or bid into the DAM pool and/ or the IDM. Especially for RES producers that operate without "green tariffs" the detailed market rules should allow aggregation i.e. these RES producers could formulate groups and collectively place orders into the DAM. Direct participation to the wholesale market involves balancing responsibilities (either directly or through BRPs) similar to those imposed to any other producer. At a later stage these RES plants could also perform as BSPs.

10.5 RES under green tariffs with installed capacity up to 30kW

Under the Law, electricity generated from solar energy and/or wind energy by electric power facilities (generating installations) of private households, with an installed capacity not exceeding 30 kW, shall be purchased by Universal service providers within a framework of public service obligation at "green" tariff in the volume that exceeds monthly electricity consumption by such private households. Household consumer shall have the right to install in his/her private household a generating installation designed for the production of electricity from solar energy and/or wind energy with installed capacity not exceeding 30 kW but not exceeding the capacity permitted to consume under contract of accession. Electricity generation from solar energy and/or wind energy by private households shall be carried out without relevant license. The procedure for the sale and metering of such electricity as well as for payments for it shall be approved by the Regulator.

Considering the demand side of Universal service providers, it is expected that they will be capable of managing these quantities along with their demand portfolio. Within this frame, no forecast obligations should apply to RES plants owners of this category.

To allow Universal service providers to better exploit all synergies emerging out of this obligation, they will forecast corresponding generation cumulatively and take it into account as negative load i.e. their offtake nominations at the OTC platform and Demand Orders in the DAM and IDM should be netted with forecast injections for RES plants below 30 kW.

Universal service providers are therefore responsible (either directly or through their BRP) for the total (netted) consumption they nominate which incorporates the imbalances from injections by RES plants below 30 kW.

The above arrangements are proposed because the imbalance caused by the operation of the RES plants in this category (in some cases) cannot be measured separately and therefore any benefit or burden caused to the Universal service providers cannot be assessed and remunerated, at least on the basis of accurately measured quantities. In any case, Universal service provider sare paying corresponding RES plants the "green tariff" for the actually metered quantities and therefore it is acceptable for them to bear the relevant imbalance cost /benefit.

11. Other Market Features

11.1 Security Cover Requirements

Energy trading through the Day Ahead Market, the Intra Day Market and the balancing market entails credit risk for the MO and the TSO against which appropriate security cover should be imposed.

For the Day Ahead Market transactions, as the usual practise is in all trading platforms in Europe, the risk management process is based on a check performed by the MO: each Demand Order submitted by a Market Participant in the DAM should be covered by equal or greater amount of cash collateral. In case the check is negative, the Order is automatically rejected.

Trade limits shall be assigned to every IDM Market Participant, on the basis of the risk assessment that will be effected by the MO. A trade limit shall be a limit established by means of a monetary value, within which the IDM Market Participant can trade contracts between two settlement days. Market Participants shall not be allowed to exceed their trade limit. The same principles are applied in case a third entity undertakes the clearing of the DAM and IDM.

With regard to the cash flows settled through the TSO for balancing services procurement and imbalances settlement the proposal is the security cover to be calculated on the basis of the corresponding amounts being traded by market participants. Taking into account that there are no balancing data available for balancing providers and those to become BRPs, nor market based imbalance prices are calculated for the time being, the market rules should be drafted to reflect the absence of corresponding historical data. Based on this observation the TSO should make an approximation of BRPs' exposure to the balancing market for the next two months. The quantities should be approximated based on the trading size of each BRP. Following the first two months of activation for a BRP, the TSO should utilize corresponding actual balancing quantities (net energy purchases) during the past two months in view of accessing the quantities for the next two months. The price to be applied should be the average imbalance price of the previous two months. It is clarified that the security cover should be applied to all BRPs with respect to their net energy purchases through the balancing market. For BSPs providing downwards balancing energy corresponding guarantees could be easily approached based on each BSPs' reserved downwards capacity.

As the TSO serves as the central cashier for the gathering and allocation of various other charges applied to retail suppliers and consumers, an extra security cover is proposed to be calculated taking also into consideration corresponding amounts. The security cover may take the form of a bank guarantee or cash collaterals. When there are annual data available regarding wholesale charges imposed by the TSO, the latter may proceed in utilizing corresponding annual data to perform approximations of quantities exposure and prices development for the security cover period. It is suggested that the security cover period is set to cover appropriate amount of time (e.g. two months) so that in case of default, the TSO will be covered for accordingly sufficient time before resolving the situation. For the first twelvemonths of operation of a new retail supplier/consumer the security cover for these charges should be approximated on the basis of its scheduled trade on a bi-monthly basis (market share). Following a year's activation, the bi-monthly guarantees will be calculated based on the statistical data of the previous year.

The above process (regarding balancing and other system charges security cover calculation) is proposed in case the balancing market and imbalances settlement are assigned to an entity that brings no relevant experience in risk management as the Ukrainian TSO. However, in case a clearing house or a bank is involved then the corresponding entity will be held responsible to propose required security covers according to its standards and NEURC should approve them or require modifications up to its satisfaction.

If the TSO is in the situation of expelling a market participant because of outstanding debts at the wholesale level then we distinguish between the following cases:

- In case the participant is a supplier, its customers should be transferred to the last resort supplier and its counterparties under bilateral energy contracts should be notified accordingly so as to take appropriate measures against it as defined within their bilateral agreements.
- In case the participant is a producer, its counterparties under bilateral energy contracts should be notified accordingly so as to take appropriate measures as defined within their bilateral agreements. Corresponding suppliers will have to decide whether to continue to provide services to end customers by utilizing the DAM and IDM to purchase appropriate energy quantities or submit a request for part or the total of their consumption to be transferred to the last resort supplier. In circumstances where the safe operation of the system is jeopardized, NEURC may decide to approve step-in process to the assets of the default producer.

Under bilateral contracts, suppliers and producers should freely negotiate and conclude on the security cover suppliers will provide with respect to the energy quantities they are engaged to purchase. Those contracts should include specific terms and procedures on when a party may inform the TSO and the MO that an energy supply contract has been terminated without the consent of the other party. In the event of a producer denouncing a contract because of supplier's outstanding debts, the MO and NEURC should be immediately informed so that the latter will decide whether the supplier may continue to activate using the DAM and the IDM and any other bilateral contracts it might hold or the supplier is announced in default and has to be expelled from the total of the market. In taking corresponding decision NEURC may require the supplier to provide extra security cover to the MO in view of its expected increased utilization of the DAM and/or IDM. In case NEURC decides to expel the supplier because its outstanding debts under its bilateral contract jeopardize the smooth market operation, its customers should be transferred to the last resort supplier and its counterparties under bilateral energy contracts should be notified accordingly so as to take appropriate measures against it, as defined within their bilateral agreements.

11.2 Market Metering Requirements and Metering profiling

The efficient operation of the market depends on the availability of verified data on energy flows into and out of the system. This requires metering equipment of suitable accuracy and reliability, providing the data needed for market settlements (as well as other charges).

Note: *these issues will be detailed in the Commercial Metering Code*

11.3 Reconciliation of Metering Data

Note: *these issues will be detailed in the Commercial Metering Code*

11.4 Communication

The exchange of information between participants, the MO and the TSO (including submission of registrations, DAM Orders submission, IDM Orders, BM Bids/offers submission, notification of results and schedules defined under the DAM and the IDM) takes place by exchanging appropriate files through the Internet or by filling in appropriate forms available on the MO's and the TSO's websites (web forms).

The market information system is controlled from the trading room of the MO, which is equipped with hardware and software components permitting it to collect and process the transactions and schedules registered on the DAM, IDM and the OTC registration Platform.

The MO should furthermore be equipped with hardware and software components permitting it to communicate data to the information system of the TSO.

The MO personnel should ensure the continuous operation of the system under maximum security conditions and provide support to market participants.

Similarly, the balancing market is controlled from the control room of the TSO, which is equipped with hardware and software components permitting it to collect and process corresponding data and issue dispatching orders. The TSO personnel should ensure the continuous operation of the system under maximum security.

11.5 Market Reporting

The EU Regulation for Energy Markets Integrity and Transparency known as REMIT sets out the details and type of data to be reported by market participants, the TSO and the MO included, to the CEREMP[21]platform run by ACER (data is copied to competent NRAs).

It is proposed that during the software procurement, both in the MO and the TSO, the specifications require that data should be gathered and processed in accordance with REMIT (and its Implementing Acts) provisions and appropriate interfaces are developed to allow future data transfer to the corresponding ACER platform CEREMP.

11.6 Market Data Publishing

The Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets mandates a minimum common level of data transparency through publication of data on a non-discriminatory way. In this respect, one central information platform, managed by ENTSO-E, has been created to provide all market participants with a coherent and consistent view of the market. TSOs, and where appropriate MOs, are obliged to submit specific data on this platform.

Although the total of the Ukrainian system is not interconnected and the TSO of Ukraine is not an ENTSO-E member, it is proposed that data collection and publication rules enforced through the above mentioned EU Regulation and therefore the information system to be procured should take corresponding requirements into account. Data should at least be uploaded to the TSO's website and in time adequate interfaces should be developed to allow transmission to the ENTSO-E transparency platform.

In summary, EU Regulation 543/2013 foresees for the following data collection and publication:

- Information on national load per market time unit (e.g. hour) to be published ex-post
- Day-ached forecast of total load per market time unit to be published at least 2 hours before DAM gate closure and be updated afterwards
- Week, month and year ahead aggregated load forecasts to be published ex-ante
- Information relating to the unavailability of transmission infrastructure to be published no later than one hour after the change in availability
- Information relating to congestion management measures, if any
- Forecast of total generation

[21] Central European Register for Energy Market Participants

- Forecast of wind and solar power generation (MW) per each market time unit of the following day (RES units, above a threshold, to submit the TSO corresponding forecasts)
- Information relating to the unavailability of generating units
- Actual generation per market time unit (separately for Wind and Solar-profiled where no data is available)
- The amount of balancing reserves under contract (MW) by the TSO
- Prices paid by the TSO per type of procured balancing reserve and per procurement period (Currency/MW/period)
- Accepted aggregated offers per hour, separately for each type of balancing reserve
- The amount of activated balancing energy (MW) per hour and per type of reserve
- Prices paid by the TSO for activated balancing energy per hour and per type of reserve, price information shall be provided separately for up and downregulation
- Imbalance prices per hour
- Total imbalance volume per hour;
- Monthly financial balance

The exact publishing timing of above elements should follow the Regulation provisions.

There will be an obligation on the MO to publish at least the following market information (subject to appropriate confidentiality issues), and to maintain an archive of this information for [5] years, accessible to all Market participants and other interested parties:

- Aggregated volumes of the OTC registration platform per hour(to be published at least 1 hour before the DAM gate closure)
- Aggregated volumes of RES under green tariffs registered at the OTC platform per hourly period (to be published at least 1 hour before the DAM gate closure)
- At least aggregated volumes per type of technology (nuclear, coal, CHP, hydro , solar, wind) scheduled under the DAM per hour
- The DAM clearing price per hour and the DAM volumes scheduled for each market participant per hour.

This information shall be provided in Ukrainian, at least, and shall be made available in an efficient manner and gathered in a single interface.

11.7 Invoicing and Cash Collection

This section describes the timetable and procedures to be followed by the MO and the TSO in issuing daily and monthly invoices for payments/charges to wholesale market participants respectively.

On the [1st] business day following day D i.e. on of D+1, the MO will prepare the following:

- a notification to be send to each supplier/end consumer regarding the sum of payables in respect of all Demand Orders accepted in the DAM during the previous day
- a notification to be send to each generating unit regarding the sum of receivables in respect of all Generating Orders accepted in the DAM during the previous day
- a notification to be send to each producer, trader, or supplier/end consumer regarding the sum of receivables or payables in respect of the net outcome of the transactions accepted in the IDM during the previous day

On the [2nd] business day following day D i.e. on D+2, the MO will issue invoices towards:

- each supplier/end consumer that is debtor to the MO regarding its DAM activation during day D
- each producer, trader, or supplier/end consumer that is debtor to the MO regarding its IDM activation during day D

On the [3rd] business day following day D i.e. on D+3:

- Producers issue invoices towards the MO regarding Generating Orders acceptance through the DAM during day D
- Producers, traders, or suppliers/end consumers issue invoices towards the MO regarding IDM activation during day D, in case the net outcome is receivable

On the [3rd] business day of M+1, the TSO will prepare the following:

- a notification to all balancing services providers regarding their net financial position in respect of accepted bids and offers in the BM during the previous month
- a notification to all BRPs regarding their net financial position in respect of registered, per hour, imbalances of the previous month
- a notification to all retail suppliers/end consumers as to the uplift charges, network fees and other levies applied for month M.

On the [10th] business day of M+1, the TSO will issue invoices towards:

- each BSP that is debtor regarding its BM activation during month M
- each BRP[22] that is debtor under imbalances settlement during month M
- each retail supplier/consumer regarding the uplift charges, network fees and other levies applied for month M.

On the [15th] business day of M+1:

- BRPs issue invoices towards the TSO in case they are receivers under imbalances' settlement during month M
- BSPs issue invoices towards the TSO in case they are receivers regarding BM activation during month M.

[22] It is clarified that each market participant may be a BRPs itself or sign with a third BRP.

In case of disputes over the volumes or other data registered under each market participant, the invoice should be paid and any dispute regarding data accuracy dealt with later.

Where after a dispute, it is recognised that there has been an error in a market participant's invoice charge or metered quantity in one or more settlement periods, the MO and/or the TSO will determine the adjustments to be made to all market participants' invoices, which may involve re-running settlement calculations for the relevant and any subsequent periods. Any such adjustments will appear as a supplementary item in each invoice at the next invoice cycle.

Payments by DAM and IDM market participants to the MO account should be made within [1] business day from the date the invoice has been issued. Payments by the DAM and IDM market participants to the MO should precede payments by the MO to DAM and IDM market participants to minimise the MO exposure. The MO should pay DAM and IDM market participants within [2] business days from the date corresponding invoices have been issued.

Payments by market participants to the TSO account should be made within [5] business days from the date the invoice has been issued. Payments by market participants to the TSO should precede payments by the TSO to market participants to minimise the TSO exposure. The TSO should pay market participants within [5] business days from the date corresponding invoices have been issued.

As analysed under section9.5 the financial sum of all balancing provision actions and imbalance settlements, for the total of market participants and for the same settlement period, might not be zero meaning a residual will sometimes be gathered to the TSO account. The corresponding cost or surplus is proposed to be socialised as per para 9.5.

In the event of non-payment of an invoice, the TSO should use the security cover for the unpaid amount.

11.8 Emergencies

The procedures whereby the TSO declares a system emergency should be set out in the Transmission Electricity Network Code. Market Rules though should provide that in the event of an emergency in the electricity, the ordinary processes of the market arrangements would be suspended for the duration of the system emergency and administratively defined prices will apply. The DAM and IDM Rules as well as the Market Rules should also provide that where market participants incur additional costs supporting the TSO in its response to a system emergency, they may recover these costs under justified claims and following NEURC's approval. It is clarified that these costs should not be passed to end consumers as PSOs. Those costs occur at the wholesale level and following NEURC's approval should be attributed to corresponding market players at the wholesale level, on the basis of their operation during the emergency.

The MO and the TSO should also set procedures regarding market suspension in case the information systems they operate face major problems such as not being possible to receive, orders, nominations or bids and offers from market participants.

11.9 DAM and IDM Rules, Market Rules and Manuals

Considering that almost all processes should be developed from scratch there are synergies that the total of market arrangements (i.e. the OTC registration platform, the DAM platform, the IDM platform, the balancing process and the imbalances as well as other settlement processes) are developed under a common information system that will provide for the appropriate interfaces between the different segments. However, it is also possible that the MO and the TSO procure their systems separately making sure though that appropriate interfaces are developed.

Technical processes and details of the market operation should be also included in the manuals that accompany the DAM and IDM Rules, as well as the Market Rules. The manuals should be developed by the MO (and the TSO with regard to the balancing and imbalances settlement processes) and approved by the regulator.

The MO and the TSO should publish the manuals for the operation of the various market segments at their web sites. By the time the information system is finalised and tested corresponding manuals, in their final format, should be approved and published.

DAM and IDM Rules as well as Market Rules should develop appropriate formulas as per the current design taking into consideration that the parameters appearing in brackets [ ] will be defined by NEURC decisions on a yearly basis.

12. Demand Response

Demand Response is proposed to be applied at a later stage. However, this Section provides for a brief analysis which demonstrates that the proposed arrangements could, under appropriate additions, accommodate this service in case, in the future, it is considered that such a service provides added value to the electricity sector of Ukraine.

Demand Response is a service that can be provided either by retail suppliers serving load or by entities (Demand Response Agents) who aggregate smaller retail customers and directly bid corresponding capacity into the wholesale markets. In this respect Demand Response programs run by the DSO could directly participate in the wholesale arrangements as well.

Demand Response Agents should therefore accede to the DAM and IDM Rules and the Market Rules and become market participants.

In case of demand response, corresponding Agents should also be allowed to offer load curtailment at the DAM (or IDM) stage under arrangements that approximate those of generating units' orders. However, since the DR Agent may not coincide with the retail supplier representing corresponding load, the latter will be also compensated in case of load curtailments i.e. the system will effectively double pay the same service. It is therefore required that the supplier's Physical Position after the DAM closure is appropriately adjusted in case the DR Agent has scheduled a demand curtailment in the DAM and /or the IDM. For such an adjustment to be possible, each DR Agent should submit Orders in the DAM and make transactions in the IDM per portfolio of meters registered under each retail supplier.

Obviously, by the time DR is activated through the wholesale arrangements, the metering representation Registry should further foresee who the DR Agent is, under each meter.

The DR Agent will receive the DAM price for the curtailed quantities (or its limit price in the IDM) and later should be checked against a baseline. There are several methodologies developed worldwide on how corresponding baselines could be calculated.

The adjustment of the retail supplier's physical position should be made on the basis of the volume approximated by the baseline methodology as actually curtailed.

Similarly the DR Agent should be possible to place offers for demand curtailment at the BM. The design already foresees for suppliers representing large dispatchable load or dispatchable load itself to submit corresponding offers. However in case DR enters the wholesale market then offers to the BM should only be made by one entity: the DR Agent (which though could be theretail supplier itself). Similar arrangements to those applied when demand response is scheduled under the DAM, apply and in case demand response is activated in the BM.

As ultimately the income from the corresponding service should be passed to the retail customers, the DR Agent and the retail supplier (in case these are different entities) should proceed with bilateral arrangements which will provide for the income to be reflected in supplier's retail tariffs to end consumers.

For DR to be smoothly integrated within wholesale market arrangements sufficient technical and metering capabilities need to be developed therefore the proposal is that for the moment only dispatchable load participates with offers for demand decrease or demand increase within the BM. However, in a few years the design should accommodate such settlement arrangements that will make possible DR activation by corresponding Agents, even through the Dam and/or the IDM

It is clarified that DR may also bid to the ex-ante contracts for operating reserve capacity organized by the TSO, provided corresponding Agent holds appropriate technical characteristics to respond within the time frame set by the TSO for each type of reserve activation.

ANNEX A

Block Generation Orders

A block Generating Order is an Order defined by:

- a fixed price limit (minimum price for generating block),
- a number of periods,
- a volume that can be different for every period, and the
- minimum acceptance ratio.

In the simplest case, a block is defined for a consecutive set of periods with the same volume for all of them and with a minimum acceptance ratio of 1 (regular “fill-or-kill” block orders). These are usually called regular block orders. However, in general, the periods of the blocks can be non-consecutive, the volume can differ between periods and the minimum acceptance ratio can be less than 1 (partial acceptance).

Acceptance of the Generating Block Orders is based on the following principles:

- in case the block volume weighted average market clearing price for the periods during which the block is defined is above the price of the block, then the block can be entirely accepted, which means that all the energy in the block is accepted;
- in case the block volume weighted average market clearing price for the periods during which the block is defined is below the price of the block, then the block must be entirely rejected;
- in case the block volume weighted average market clearing price for the periods during which the block is defined is exactly the price of the block, then the Block can be either fully rejected, fully accepted or partially accepted, to the extent that the ratio “accepted volume/total submitted volume” is greater than or equal to the minimum acceptance ratio of the block and equal over all periods.

Block orders can be linked together (Linked Block Orders), i.e. the acceptance of individual block orders can be made dependent on the acceptance of other block orders. The block which acceptance depends on the acceptance of another block is called “child block”, whereas the block which conditions the acceptance of other blocks is called “parent block”.

The principles for the acceptance of linked block orders are the following:

- The acceptance ratio of a parent block is greater than or equal to the acceptance ratio of its child blocks
- Possibly partial acceptance of child blocks can allow the acceptance of the parent block when:

  - the surplus of a family is non-negative
  - block orders without child blocks do not generate welfare loss
- A parent block which is out-of-the-money can be accepted in case its accepted child blocks provide sufficient surplus to at least compensate the loss of the parent
- A partially accepted child block must be at-the-money if it has no parent blocks that are accepted
- A child block which is out-of-the-money cannot be accepted even if its accepted parent provides sufficient surplus to compensate the loss of the child, unless the child block is in turn parent of other blocks (in which case rule 3 bullet applies).

ANNEX B

M-1	**Reserves procurement by type of reserve and for each hour of month M (groups of hours could be formed and tendered separately)**
D-2 by 13:00	OTC contracts registered on a portfolio basis
D-1 by 7:00	Participants nominate to the TSO (copied to the MO) the long term PTRs they are going to use
D-1 by 9:00	Submission of Physical Delivery Nominations and Physical Offtake Nominations
D-1 by 9:15	The MO confirms Physical Nominations or sends out inconsistency notifications
D-1 by 10:00	Participants may submit corrected Physical Nominations
D-1 by 10:00	The results of the daily PTRs allocation are copied to the MO DAM platform
D-1 by 10:30	The MO issues final confirmation/rejection of OTC transactions
D-1 by 10:30	The DAM opens and interested participants may start placing Orders
D-1 by 13:00	The DAM closes
D-1 by 13:45	DAM final results are notified to participants
D-1 by 14:30	BRPs submit to the TSO the Physical Nominations for each hour of next day D
D-1 by 14:30	BSPs provide Generation(Load) schedules for each hour of next day D
D-1 by 15:00	The IDM opens for all 24 hours of day D
Day D 60’ before hour h	The IDM closes for hour h

Day D 50' before hour h	BSPs provide updated Generation(Load) schedules for hour h
Day D 50' before hour h	BRPs submit Final Physical Positions for hour h
Day D 45' before hour h	Deadline for bids and offers submission for balancing energy for hour h
Day D 30' before hour h	The TSO issues balancing instructions towards BSPs for hour h

Abbreviations Table

ACER	Agency for the Cooperation of Energy Regulators
AS	Ancillary Service
BM	Balancing Market
BNE	Best New Entrant
BRP(s)	Balance Responsible Party(ies)
BSP	Balancing Service Provision
CACM NC	Capacity Allocation and Congestion Management Network Code
NEURC	UkrainianNational Energy Regulatory Authority
CEREMP	Central European Register of Energy Market Participants
CfDs	Contract for Differences
CSP	Central Scheduling Process
DAM	Day Ahead Market
DR	Demand Response
DSO	Distribution System Operator
DUoS	Distribution Use of System
EB	Electricity Balance
EB NC	Electricity Balancing Network Code
EET	Eastern European Time
ENTSO-E	European Network of Transmission System Operators for Electricity
FCA NC	Forward Capacity Allocation Network Code
FCR	Frequency Containment Reserves
FG	Framework Guidelines
FRR	Frequency Restoration Reserves
GME	GestoreMercatiEnergetici –The Italian Market Operator
IDM	Intra Day Market
IPP	Independent Power Producers
MO	Market Operator
NC	Network Codes
NRA	National Regulatory Authority
OTC	Over the Counter

PCR	Price Coupling of Regions
PSO	Public Service Obligations
PTR	Physical Transmission Right
REMIT	Regulation (EU) 1227/2011 on wholesale energy market integrity and transparency
RES	Renewable Energy Sources
RR	Replacement Reserves
TSO	Transmission System Operator
TUoS	Transmission Use of System
VoLL	Value of Lost Load