E-CONTROL

Discussion paper
concerning the amendment of the gas market rules
to reflect the Natural Gas Act 2011

E-Control consultation paper on principles

Version 1.0

November 2011

Contents

1 Purpose of the document

This discussion paper and the principles presented in it aim to attain the goals of the new *Gaswirtschaftsgesetz* (Natural Gas Act). The 2011 Natural Gas Act provides for the introduction of an entry/exit regime, which requires a number of adjustments to the current market rules. With this document, Energie-Control Austria (E-Control) wishes to contribute to the discussions towards the detailed design of the market rules; this paper and the subsequent consultation of market participants are meant as preparatory work for the contents of the ordinances to be issued by E-Control, for the general terms and conditions of the relevant natural gas undertakings and for the gas market code.

Market participants are invited to send their comments on the concepts in this document and their replies to the questions presented to marktregeln@e-control.at by 15 December 2011 at the latest.

2 Legal basis

The 2011 Natural Gas Act is the legal foundation of the Austrian market rules. In consideration of Regulation (EC) No 713/2009 establishing an Agency for the Cooperation of Energy Regulators, the Act transposes

1. Directive 2009/73/EC concerning common rules for the internal market in natural gas (Gas Directive) and
2. Directive 2006/32/EC on energy end-use efficiency and energy services; as well as the stipulations in
3. Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks and
4. Regulation (EU) No 994/2010 concerning measures to safeguard security of gas supply

reserved for implementation by the member states.

This framework for the detailed design of the market rules is complemented by the progress made at European level regarding the framework guidelines and network codes in accordance with Regulation (EC) No 715/2009, as well as by the European guidelines which, as annexes to Regulation (EC) No 715/2009, become directly applicable in all member states by way of comitology.

3 Basic principles

To ensure that the design of the new market rules builds on the extensive knowledge and practical experience of market players, E-Control started a series of altogether 23 bilateral meetings, guided by a fixed set of questions, with a number of market participants in April 2011. In these thorough discussions with system operators, traders, suppliers, shippers, representatives of the *Fachverband der Gas- und Wärmeversorgungsunternehmen* (Natural Gas and District Heat Association) and institutions such as the control area manager and the clearing and settlement agent (CSA) of the eastern control area a number of topics where adjustments are necessary or desired were identified.

The meetings indicated that the new market model should be as straightforward and transparent as possible. Means to achieve this goal should include a one stop shop for concluding and handling balance group contracts (s. Figure 1: Results of bilateral meetings concerning the need to introduce a one stop shop for concluding and handling balance group contracts

), harmonised organisational rules in the market area (s. Figure 2: Results of bilateral meetings concerning the need to harmonise the organisational rules within the market area

), as well as transparent determination and cost-efficient adjustment of collateral.

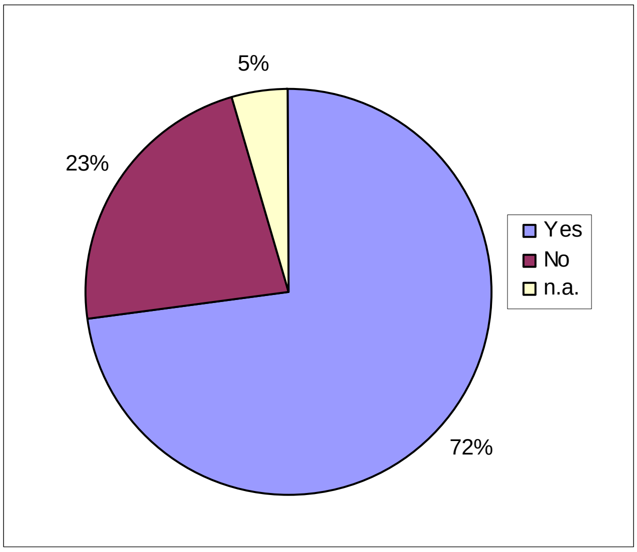

Figure 1: Results of bilateral meetings concerning the need to introduce a one stop shop for concluding and handling balance group contracts

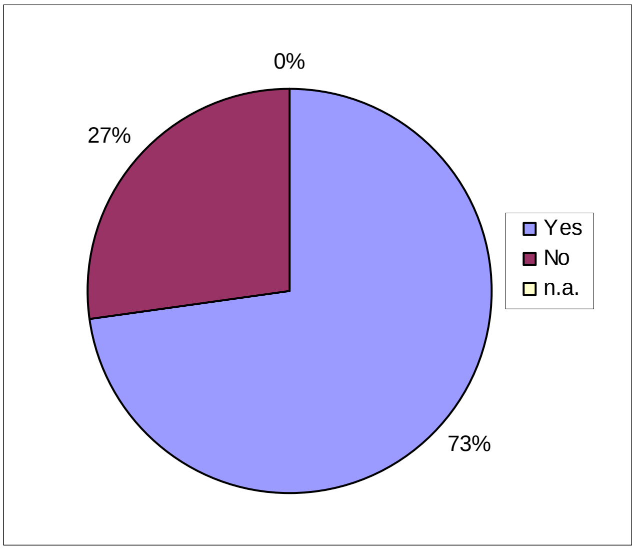

Figure 2: Results of bilateral meetings concerning the need to harmonise the organisational rules within the market area

The outcome of the bilateral sessions has been used in developing the chapters below.

3.1 Balancing regime

In addition to the new Natural Gas Act, the balancing regime in the new market rules should take into account the known or likely outcome of discussions at European level. This particularly applies to the Framework Guidelines on Gas Balancing in Transmission Systems.[1] The basic rules that can be derived from these Framework Guidelines include:

- Transmission system operators (TSO) / market area manager (MAM) must procure balancing energy by buying and selling standardised products on the wholesale market.
- The balancing period is a daily standardised interval, at the end of which financial settlement for imbalances accumulated over the preceding 24 hours takes place.
- The gas day means the period from 5:00 to 5:00 UTC for winter time and from 6:00 to 6:00 UTC when daylight saving is applied or any other time period set in the network code on capacity allocation mechanisms.
- Incentivising network users to engage in balancing activities during the day is admissible if this serves to ensure system stability and to minimise the need for the TSO / MAM to

[1] s. ACER, Framework Guidelines on Gas Balancing in Transmission Systems, 18 October 2011, http://www.acer.europa.eu/portal/page/portal/ACER_HOME/Public_Docs/Acts%20of%20the%20Agency/Framework%20Guideline/Framework%20Guidelines%20on%20Gas%20Balancing%20in%20Tr/FG%20Gas%20Balancing_final_public.pdf

take balancing actions, and if network users are provided with sufficient information to enable them to comply with any within-day obligations.

- The price for balancing energy must reflect the market price for balancing energy procured by the TSO / MAM, i.e. the lowest priced offers or the highest priced bids; this market price may be adjusted slightly to incentivise network users.
- Information about injection and offtake quantities, in aggregate form and itemised per network user, about balancing activities by the TSOs / MAM and about the overall status of the system must be made available in a timely manner and on the same timescale to all network users in order for them to be able to take necessary actions to correct their imbalances where this is economically feasible.
- Together with distribution system operators (DSOs) / distribution area manager (DAM), TSOs / MAM must provide forecasts of offtake volumes for non-daily metered customers at the day-ahead stage and update them at least twice during the balancing period, i.e. twice a day.
- TSOs are required to cooperate in order to integrate European gas markets by merging entry/exit zones or creating cross-border balancing zones wherever this is technically feasible and economically reasonable.

The above rules must be applied in a harmonised way within a market area and DSOs must cooperate with TSOs in their implementation.

In compliance with EU-level rules and as outlined in the Natural Gas Act 2011, the main building blocks of the balancing regime in the new market model are:

- The MAM is created for managing and registering balance groups (one stop shop), organising the clearing and settlement of imbalances for balance groups that do not supply consumers, coordinating the TSOs, calculating and announcing capacity, and establishing the virtual trading point (VTP) and the capacity trading platform.
- In the interest of increasing liquidity, all trading activities as well as entries to and exits from the market area are concentrated at the virtual trading point. Also shippers that only transit natural gas through the market area must be members of a balance group in this market area.
- The clearing and settlement of consumption deviations in balance groups that supply consumers, as opposed to pure trading balance groups, is done by the clearing and settlement agent.

- All balancing activity in the market area should primarily take the form of exchange trading at the VTP. A variety of products (with different reference periods or locations) might be needed to address all balancing needs; MAM / DAM must ensure that these products are employed in the technically and economically optimal manner.
- MAM and DAM cooperate to coordinate the use of linepack in the entire market area.

Concentrating all market area injection and offtake at the VTP requires centralised registration and balancing of all gas flows, including transits. Clearing of trades lies with the MAM while clearing of supply to consumers remains with the clearing and settlement agent; however, both institutions must use a clearing and settlement system.

The behaviour of transit shippers has so far created only little need for physical balancing energy on part of the TSO: shippers nominated the necessary capacity for their transports from the injection point through to the withdrawal point along the transport path and were interested in the actual transport of the gas nominated. Any deviation was usually caused by factors outside the shippers' control (e.g. steering differences, restrictions in the upstream grid). The entry/exit regime now provides for separate nomination of entry and exit capacity. Should a balance group that does not comprise metering points, i.e. one that does not supply consumers, produce a difference between entry nominations plus net trades and exit nominations, an imbalance in the balance group would result and would need to be dealt with by the TSO / MAM using linepack or physical balancing energy.

To avoid such situations, the balancing regime can incentivise balance responsible parties (BRPs) to engage in balancing activities for their balance groups themselves. Procurement and portfolio balancing should take place at the virtual trading point instead of a separate balancing energy market. In addition, there might be a role for the current merit order list system, with some adjustments, as an emergency instrument. On top of that, an uncontrolled development of the need for balancing energy must be prevented by dedicated rules which ensure that scheduling and nominations are as precise as possible; for instance, BRPs could be obliged to include all the information available to them in scheduling and nominating – balance groups without forecasting risk should thus be able to maintain their balance.

Questions:

1.)	What could hourly incentives within a daily balancing period in the eastern market area look like?

2.) At EU-level, a gas day at transmission level is defined to start at 6 a.m. and end at 6 a.m. the following day. E-Control proposes to apply this definition across all three market areas in Austria as the market rules are amended, thereby eliminating the barrier created by the currently differing gas days. Do you see any reasons why differing gas day definitions should be maintained?

3.) Separate handling of clearing and settlement for trading and for supply to consumers gives rise to the question whether, in spite of a system being used, two different balancing energy prices should be admissible, thereby possibly creating arbitrage opportunities.

4.) How could the merit order list system be adjusted to create an effective emergency instrument which can handle products that differ in reference periods and locations?

3.2 System access and capacity management

3.2.1 Entry and exit capacity at the borders of the eastern market area

The new Natural Gas Act provides for the introduction of an entry/exit regime. The transmission network is accessed by booking capacity at the transmission network's entry/exit points that can be freely allocated and traded and by entering such booked capacity into balance groups (s. section 31 Natural Gas Act 2011). Entry capacity rights entitle the holder to inject gas into the transmission network and to transport it to the market area's VTP. Exit capacity rights entitle the holder to transport gas from the VTP to the exit point and to withdraw it from the transmission network. Such a regime requires efficient management of entry and exit capacity, based on the following principles:

1. The amount of announced capacity must be maximised (s. sections 34 and 35 Natural Gas Act 2011 and the draft network code on capacity allocation of ENTSOG[2]).
2. Capacity products must be designed to meet market needs (s. section 36 Natural Gas Act 2011 and the draft network code on capacity allocation of ENTSOG).
3. Capacity allocation must be non-discriminatory and adequately reflect the congestion situation (s. section 32 Natural Gas Act 2011 and the draft network code on capacity allocation of ENTSOG).

[2] s. Network Code on Capacity Allocation Mechanisms, An ENTSOG Network Code proposal for market consultation, 21 June 2011, and ENTSOG second formal consultation on new or modified concepts, 24 October 2011, http://www.entsog.eu/publications/index_g_cam.html

4. There must be adequate ways for market participants to exchange capacity with each other (s. sections 31, 38 and 39 Natural Gas Act 2011 and the draft network code on capacity allocation of ENTSOG).
5. As a rule, unused capacity must be made available to the market (s. draft guidelines on congestion management procedures of the European Commission[3]).

General provisions concerning points 1 through 4 above are contained in the Natural Gas Act 2011; more detailed ones are currently being developed by ENTSOG in its network code on capacity allocation mechanisms. The current time plans suggest that the provisions from the network code can be implemented as from the same date as the relevant ones in the Natural Gas Act, i.e. 1 January 2013, in spite of implementation periods that might be foreseen. Therefore, it does not currently seem necessary to include further regulations on the ground rules under points 1 through 4 above in the market rules. However, the market rules need to address point 5 above.

Question:

5.)	Do you think additional ground rules are needed to ensure efficient capacity management at the market area's entry/exit points? If so, which ones?

3.2.2 Short-term capacity management

The mechanisms for interruptible capacity booking and secondary trading which are currently in place have not so far ensured that unused capacity can be used efficiently. However, the evolution of interruptible day-ahead capacity sales suggests that many market players would like to execute short-term cross-border deals. This is a positive development which also increases liquidity of the markets and should be supported by way of adequate rules.

The draft guidelines on congestion management procedures of the European Commission provide for a number of obligatory mechanisms which will most likely become directly applicable as of mid-2012:

- overselling and a capacity buy-back regime for TSOs
- surrender of capacity to the TSO

[3] s. the presentation of the European Commission at the XX Madrid Forum, Congestion Management Procedures, Impact Assessment and draft Commission Proposal, 27 September 2011, http://ec.europa.eu/energy/gas_electricity/forum_gas_madrid_en.htm

- long-term UIOLI

The draft guidelines also foresee that national regulatory authorities may impose short-term UIOLI in addition to the other mechanisms provided for in the guidelines. To improve utilisation of cross-border capacity, particularly with Germany, Italy and Hungary, E-Control will develop a firm day-ahead UIOLI mechanism based on section 41 para 3 item 5 Natural Gas Act 2011 and submit it to consultation. Firm day-ahead capacity should then be allocated on day D-1 in explicit auctions.

Question:

6.)	Is the introduction of short-term capacity management in addition to the instruments provided for in the congestion management guidelines sufficient to create a close link with neighbouring markets?

3.2.3 Capacity management at distribution level

It is crucial for BRPs that the interface between the transmission and the distribution level not be linked to unreasonable transaction costs, which can result, for instance, from differing definitions of the gas day, different deadlines to be followed or different requirements for data exchange. Discussions at European level concerning market integration and the gas target model[4] have identified two options for this interface: ‘market area’ or ‘trading region’. The latter depends on cross-border implementation: there can be no national trading regions, and even cross-border ones are only considered a stepping stone towards the establishment of a cross-border market area.

Capacity management at the internal interconnection points from the transmission into the distribution network in the eastern market area lies with the DAM (s. section 18 Natural Gas Act 2011). It is also responsible for handling nominations with the TSOs at these points. Capacity management by the DAM also extends to the capacity needed for connecting storage and production facilities to the VTP.

E-Control aims to eliminate the need for BRPs to make nominations and for the DAM to take capacity management measures at these internal interconnection points. This is only possible if,

[4] s. Florence School of Regulation, Jean-Michel Glachant, A vision for the EU Target Model: The MECO-S Model, EUI Working Papers, RSCAS 2011/38, June 2011, www.eui.eu/RSCAS/Publications/

in the interest of uniform rules in the entire market area, the gas day, nomination and scheduling deadlines and requirements for data exchange are harmonised between the transmission and distribution levels. Building on section 41 para. 4 Natural Gas Act 2011, E-Control will develop rules in this regard and submit them to consultation.

3.3 Contractual relations

Given the large number of institutions in the eastern market area, simple and straightforward processes must be developed for the market entry of new BRPs and for the day-to-day communication with existing ones. They must be robust and allow for automation. The MAM takes a central role (one stop shop) in this model (s. section 14 para. 1 item 2 and section 91 para. 2 item 1 Natural Gas Act 2011). Signature of a balance group contract with the MAM at the same time implies the conclusion of contracts with the operator of the VTP and, if the balance group intends to supply consumers, with the CSA and DAM.

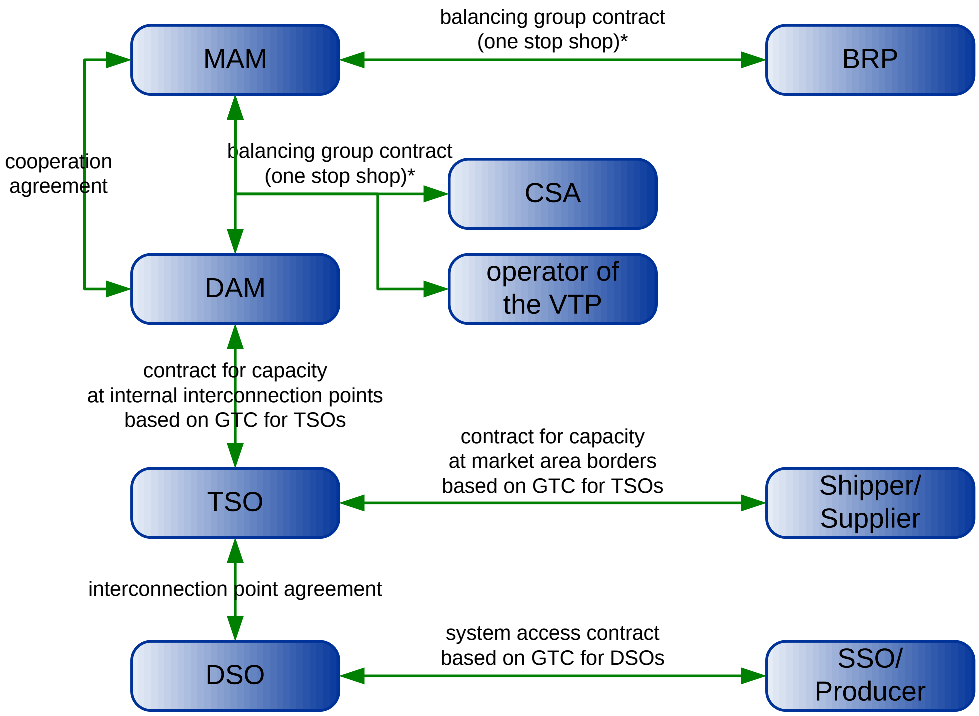

Figure 3: Overview of new contractual relations in the market area

*includes the contract with the MAM, operator of the VTP and, where applicable, DAM and CSA

MAM and DAM must support and coordinate with each other in the execution of their tasks and obligations; for this purpose, they conclude a cooperation contract pursuant to section 19

Natural Gas Act 2011. The DAM concludes capacity booking contracts with the TSOs in accordance with section 18 para. 1 item 1 Natural Gas Act 2011. Parties entitled to system access sign capacity booking contracts with the TSOs in accordance with section 31 Natural Gas Act 2011. System operators conclude interconnection point agreements pursuant to section 67 Natural Gas Act 2011 with each other. Producers and storage system operators (SSOs) sign system access contracts with system operators in accordance with section 27 Natural Gas Act 2011.

3.4 Tyrol and Vorarlberg market areas

The market areas Tyrol and Vorarlberg are not physically connected to the rest of the Austrian gas grid but exclusively fed from the German network. This situation and the overall aim of market integration command that a stepwise harmonisation of the market rules in these market areas with the market area NetConnect Germany (NCG) take place.

In a first step, cross-border balancing should be introduced to enable retailers to fully or partially supply their customers from the adjoining NCG market area. Such cross-border balancing creates a very strong link between adjoining markets without the need for full harmonisation of the balancing rules. The only requirement is that the same balancing period be used in both markets. Where this is a daily interval, the same gas day must apply. In addition, the following rules must be followed:

- A supplier that has a balance group in each of the adjoining balancing zones may exercise cross-border balancing.
- This supplier’s imbalances in each of the balancing zones are added up.
- The supplier can assign these overall imbalances to one of the two balancing zones and engage in balancing activities according to the rules that apply there.
- Cross-border balancing requires close cooperation and coordination between the institutions responsible for clearing and settling imbalances in the two balancing zones.
- The possibility for cross-border balancing is restricted by the technical capacity at the interconnection points between the balancing zones (Kiefersfelden and Lindau). If cross-border balancing would result in load flows that cannot be realised at the interconnection point in question, it takes place only to the extent of the available capacity.

Following a cost-benefit analysis, the second step would consist in full market integration of the Tyrol and Vorarlberg market areas into the NCG market area by participation of the Austrian system operators in NCG at the conditions of the German cooperation agreement[5].

This would have the following implications:

- The balancing period and the gas day would have to be adjusted to the definitions that apply in Germany. The system operators would have to send their daily data, in particular regarding the forecast offtake quantities for each customer, to the market area manager NCG. Tyrol and Vorarlberg would need to introduce all rules of the German balancing regime “GaBi Gas”.
- Cost cascading: currently, transport customers pay the exit charges to the upstream German system operator (Bayernnets / GVS). Full market integration would mean that the Austrian system operators would need to include the costs for these exit charges payable to the upstream German system operators into their own charges (which would need to be approved by E-Control as part of the allowed cost at grid level 1). The system charges in the Tyrol and Vorarlberg network areas would have to be paid by the suppliers.
- Capacity booking at the interconnection points Kiefersfelden and Lindau would be replaced by the Austrian system operators participating in the annual German internal ordering procedure at Bayernnets and GVS.
- All IT processes would have to be streamlined.

Section 12 para. 6 Natural Gas Act states that the operational coordination of systems in a market area which fully relies on supplies from a neighbouring member state and for which no separate balancing energy market exists with the adjoining system operator of that neighbouring member state must enable partial or full supply from the adjoining market area of the member state. Building on section 41 Natural Gas Act 2011, E-Control will develop rules for the implementation of the first step of market integration and submit them to consultation.

Question:

7.)	Can the goal set in section 12 para. 6 Natural Gas Act 2011 be attained by means other than the ones described above? If so, which are these?

[5] s. the cooperation agreement between the operators of gas supply systems in Germany, 30 June 2011, http://www.bdew.de/internet.nsf/id/DE_Kooperationsvereinbaru-Gas (German only)

4 Development of market rules: organisational cornerstones

4.1 Studies

E-Control has tasked KEMA Consulting GmbH with drawing up studies to prepare the development of detailed rules for the balancing regime and the entry/exit regime. For the study on the balancing regime, KEMA conducts quantitative and economic analyses based on network modelling, with the aim to assess the impact that changes to the balancing regime would have.

For the study on the entry/exit regime, KEMA analyses the principles underlying future tarification in Austria. This is complemented by a review of experience from selected European countries.

KEMA will present the interim results of both these studies on 20 December 2011 and the final results on 2 February 2012; all interested market participants are invited to attend these two one-day workshops, both of which will take place in Vienna.

4.2 Schedule

The delayed adoption of the new Natural Gas Act creates a rather tight timeframe for E-Control. The following timeline for completing the new market rules will leave sufficient time for market participants to put these new rules into practice:

- kick-off, at which the discussion paper is presented: 14 November 2011
- consultation of the discussion paper: closes on 15 December 2011
- public presentation of the interim study results: 20 December 2011
- period for comments on the interim results: closes on 13 January 2012
- public presentation of the final study results and presentation of draft market rules: 2 and 3 February 2012 (two-day workshop)
- period for comments on the final study results and the draft market rules: closes on 9 March 2012
- completion of market rules ahead of the official assessment proceedings: 30 March 2012
- official assessment proceedings concerning the market rules: close on 30 April 2012
- publication and enactment of market rules: 18 May 2012

5 Further aspects

This chapter is dedicated to a number of topics that are intrinsically linked to the design of the market rules. However, given that not all of these many topics are equally interesting to all parties concerned with the market rules, they will be handled separately. In the interest of giving a comprehensive overview, the crucial points are addressed below and reactions on them are welcome.

5.1 Transformation of contracts

To enable transition of the capacity booking system to an entry/exit regime, section 170 para. 7 Natural Gas Act 2011 stipulates that the entry capacity booked by OMV Gas GmbH at the market area border for the purpose of supplying consumers be transferred to the suppliers it is assigned to to that same extent as of 1 January 2013.

The suppliers are obliged to accept the entry capacity assigned to them to that same extent. This must result in a situation where 100% of the capacity is allocated. Suppliers wishing to amend their capacity portfolio may do so after the transfer has taken place, by way of the online platform.

E-Control is of the opinion that the data available to AGGM enable allocation to the suppliers by OMV Gas. To enable contractual arrangements to be in place by 1 January 2013, the allocation must make reference either to a cut-off date to be specified or average values must be used, e.g. an annual average of the last available gas year.

E-Control is of the view that the process and allocation method should be implemented by way of amending the general terms and conditions governing the relationship between the CSA and the BRPs by the second quarter of 2012.

Questions:

8.) Should the calculation for capacity allocation make reference to a cut-off date or to the average of the last available gas year?

9.) When should the contracts be changed to enable the new arrangements to take effect on 1 January 2013?

10.) What should be the contract term for entry capacity into the primary distribution system?

5.2 Network development plan (NDP) and long-term plan (LTP)

Every year, the MAM must, in coordination with the TSOs, with due regard to the long-term plan (section 22 Natural Gas Act 2011) and after consultation of the market participants, establish a coordinated NDP (section 63 Natural Gas Act 2011). The DAM continues to draw up an LTP.

The TSOs must submit the coordinated NDP to E-Control and, provided that the statutory criteria are fulfilled, E-Control must approve this coordinated NDP and the LTP (sections 64 and 22 Natural Gas Act 2011, respectively).

The planning period for both plans must be at least ten years. The first NDP and LTP (pursuant to the Natural Gas Act 2011) must be submitted by the end of 2012 (twelve months after entry into force) at the latest.

E-Control is of the view that the DAMs of all market areas must collect information on potential capacity needs as part of long-term planning, even if there are currently no lines at network level 1.

In addition, E-Control strongly encourages that the greatest possible degree of synergy be sought between the two plans and with other relevant infrastructure planning instruments (Community-wide NDP, regional investment plans, NDPs of neighbouring countries, electricity NDPs, NDPs of the other market areas). Such synergies must particularly be exploited for the following areas:

a) harmonised assumptions on the consumption and production of gas, bearing in mind energy policy goals;
b) harmonised emergency measures;
c) common data collection;
d) common consultation of market participants;
e) structure and level of detail of cost-benefit analyses;
f) structure and level of detail of technical feasibility analyses;
g) structure and level of detail of project presentations;
h) hydraulic modelling;
i) calculation of the infrastructure standard in accordance with the Security of Supply Regulation of the EU;
j) monitoring and evaluation of project implementation in terms of time and financing;
k) consistency with the Community-wide NDP, regional investment plans and electricity NDPs.

Both the drafting process of the NDP and the further development of that for the LTP should build on past LTP experience. Normally, the processes and steps should follow a recurrent annual rhythm. In exceptional cases (where there are particularly pressing projects) the plans can also be submitted at other times.

The schedules for drafting the NDP and LTP must be parallel, and the planning rhythm at European and regional level must be taken into consideration.

E-Control suggests designing the processes so that both plans can be approved by the end of August each year. Given the need for consultation, this implies that the plans must be submitted to the authority no later than 10 June.

Questions:

11.) Is it necessary for the NDP and LTP to be approved by the end of August to trigger the relating investment decisions for the following gas year with system operators?

12.) Do you think that there are elements of the current LTP process that should be improved to arrive at a sound future drafting process?

13.) Which other aspects should be considered in the NDP and LTP processes, in addition to those mentioned?

Step	Start	End	Duration
Data collection (from market participants)	Mo 17.10.11	Fr 09.12.11	40 Tage
Planning of measures	Mo 12.12.11	Fr 02.03.12	60 Tage
Drafting of report	Mo 06.02.12	Fr 30.03.12	40 Tage
Consultation of market participants	Mo 02.04.12	Fr 11.05.12	30 Tage
Planning conference	Fr 11.05.12	Fr 11.05.12	1 Tag
Finalisation of report	Mo 14.05.12	Do 31.05.12	14 Tage
Submission for approval	Fr 01.06.12	Fr 01.06.12	1 Tag
Coordination NDP / LTP / TYNDP / GRIPs / ele	Mo 17.10.11	Fr 01.06.12	165 Tage
Consultation of representations	Mo 04.06.12	Fr 29.06.12	20 Tage
E-Control assessment	Mo 02.07.12	Do 30.08.12	44 Tage
Official decision issued	Fr 31.08.12	Fr 31.08.12	1 Tag

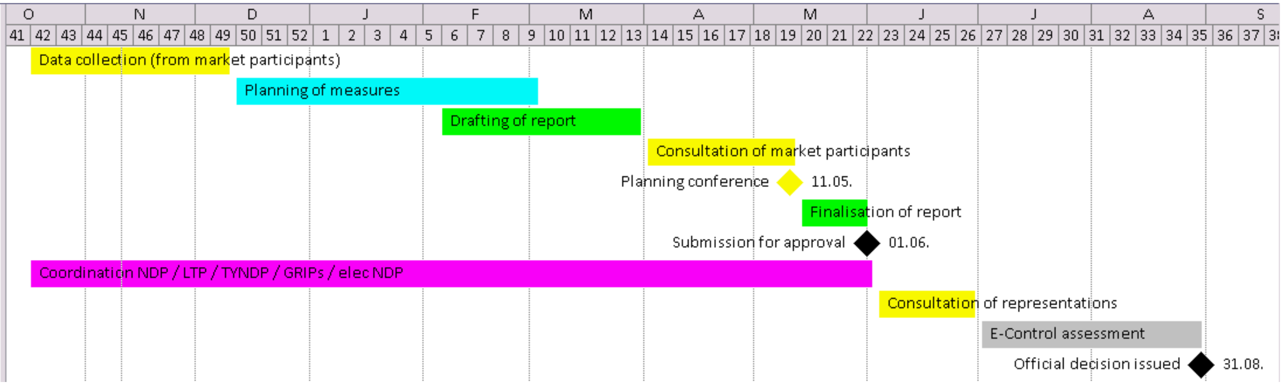

Figure 4: Coordinated NDP process schedule

Step	Start	End	Duration
Data collection (from market participants)	Mo 17.10.11	Fr 09.12.11	40 Tage
Planning of measures	Mo 12.12.11	Fr 02.03.12	60 Tage
Drafting of report	Mo 06.02.12	Fr 30.03.12	40 Tage
Consultation of market participants	Mo 02.04.12	Fr 11.05.12	30 Tage
Planning conference	Fr 11.05.12	Fr 11.05.12	1 Tag
Finalisation of report	Mo 14.05.12	Do 31.05.12	14 Tage
Submission for approval	Fr 01.06.12	Fr 01.06.12	1 Tag
Coordination NDP / LTP / TYNDP / GRIPs / ele	Mo 17.10.11	Fr 01.06.12	165 Tage
Consultation of representations	Mo 04.06.12	Fr 29.06.12	20 Tage
E-Control assessment	Mo 02.07.12	Do 30.08.12	44 Tage
Official decision issued	Fr 31.08.12	Fr 31.08.12	1 Tag

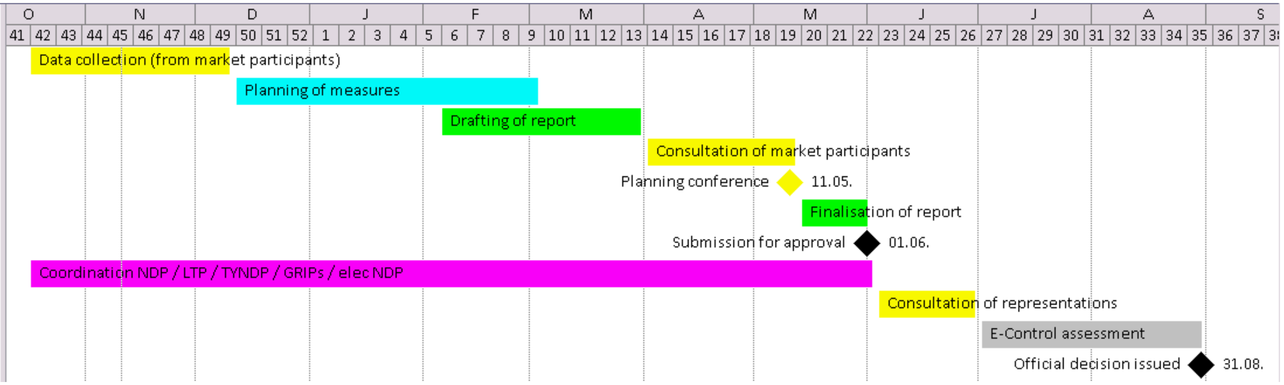

Figure 5: LTP process schedule

5.3 Entry/exit charges

Transmission-level system utilisation charges (section 74 para. 1 Natural Gas Act 2011) are to be set separately to reflect the contracted capacity per entry/exit point in the market area's transmission network on the one hand and that per internal interconnection point into the distribution network on the other; the former charge is payable by injecting/withdrawing parties, the latter by the DAM. There must be rates for firm and interruptible capacity bookings. Capacity whose free allocation is limited and flow commitments must be taken into account when setting the rates. The charges for contracts with a term of more than one day must not be substantially lower than the sum of the charges for daily contracts for this term. A minimum capacity and fees for excess capacity use may be defined. In addition, there are system utilisation charges at transmission level for storage-related exits from the transmission and distribution network, as well as system utilisation charges at transmission level for injecting natural or biogenic gas from production.

5.3.1 Basic entry/exit tarification principles

The design of the entry/exit rates, which will apply to all contracts (including existing ones), must respect the following basic principles:

- E-Control is of the opinion that where there are transmission pipelines in a market area on Austrian territory (which is currently the case for the eastern market area only), this market area should not be split up but instead function as a single entry/exit zone.
- The uniform methodology for the calculation and announcement of capacity at the entry/exit points of the market area's transmission network must minimise the amount of capacity that cannot be allocated freely or prevent such restrictions from arising at all (= maximising decoupled capacity).
- Where several transmission pipelines of various TSOs meet at one interconnection point (e.g. Baumgarten), there must be uniform entry rates and uniform exit rates. Where this causes revenues to be shifted, compensation payments apply accordingly.
- The entry rates at entry points at market level borders must be competitively neutral towards each other.
- Storage-related exit rates should generally be neutral towards each other in terms of competition, regardless of the network level, but where possible, costs are assigned directly to the parties that cause them (e.g. for the LTP).

- Production-related entry charges should generally be neutral towards each other in terms of competition, regardless of the network level, but where possible, costs are assigned directly to the parties that cause them (e.g. for the LTP).
- The charges for contracts with a term of more than one day must not be substantially lower than the sum of the charges for daily contracts for this term. E-Control considers that this point requires implementation of the European best practice.
- Fuel gas: costs for fuel gas (in €/MWh) must be assigned in a logical and transparent manner.

5.3.2 Requirements for capacity management / grid expansion

- Operational flow orders: the TSOs, in cooperation and coordination with the MAM, must tender operational flow orders in the market area e.g. on an annual basis. Offers can be submitted for individual months. Operational flow orders serve to realise firm decoupled entry and exit capacity to and from a TSO's system to the greatest possible extent. Therefore, TSOs must tender positive and negative operational flow orders.

5.3.3 Incentives for investment

- Excess revenues from auctions may only be used for measures that serve to increase announced capacity, minimise the amount of capacity that cannot be allocated freely, further market integration and security of supply; where this is not the case, such revenues will be used to reduce the system charges in the next regulatory period.

Questions:

14.) Should the rates for capacity that cannot be allocated freely be lower than those for decoupled capacity?

15.) Which further tarification principles should be introduced?

16.) Which additional investment incentives are conceivable?

5.4 Internal tariffs

Section 74 para. 1 Natural Gas Act 2011 specifies that the transmission system utilisation charge per internal interconnection point from the transmission to the distribution network is payable by the DAM. In accordance with section 24 para. 2 Natural Gas Act 2011, these costs for booking capacity at the internal interconnection points into the distribution network are allocated to the distribution system operators based on the system charges and the cost cascading principle, and to the relevant distribution system operator at each internal interconnection point from the transmission network, and are thus reimbursed to the DAM. The distribution system utilisation charge at interconnection points between the network areas is to reflect the amount of energy and/or the contracted maximum capacity and be payable by the system operators per interconnection point and/or be levied by way of the existing cost cascading procedure per network area.

In this instance, the Act allows for a cost allocation method that differs from the cost cascading procedure currently in use, and the statutory principles tied to such cost allocation would most likely entail a redistribution of costs.

Questions:

17.) Do you think that the current cost cascading procedure allocates costs in a manner that reflects causation?

18.) Should costs be allocated to reflect the contracted maximum capacity?

19.) Should cost allocation combine the current cost cascading procedure with new allocation parameters? If so, which combination would reflect cost causation?

5.5 Supplier switching

Section 123 Natural Gas Act 2011 stipulates that supplier switching must be possible within a 3-week period. The regulatory authority may detail the processes for supplier switching and for enabling new consumer connections by ordinance.

In spite of the delay in the adoption of the Natural Gas Act 2011, the 3-week period for switching has already been implemented by way of switching lists, specified in the *Gas-Wechsel-Verordnung* (Gas Switching Ordinance) 2011, as of 2 April 2011. Some of the new elements of the Gas Switching Ordinance 2011 are that it is now sufficient for the network operator to conduct spot tests to verify the supplier's power of attorney; that the new supplier must alert the customer to the possibility of reading the meter him/herself; that the current supplier confirms the termination of the contract to the customer if the latter gives notice him/herself etc.

Section 123 Natural Gas Act 2011 also provides for a data transmission process which is handled by way of a decentralised electronic platform operated by the CSA and which must also take place within the overall 3-week period. Building on the standards in the electricity and gas market, it will be part of the process of drawing up the market rules to identify the particularities that must be taken into account for the gas switching process. For instance, the redefinition of tasks and responsibilities relating to verifying the capacity allocation for a consumer who wants to switch supplier or who desires system access might create the need to introduce rules that differ from the switching process on the electricity market. In this context, it might turn out that such capacity verification, which has so far been exercised by the control area manger, is not even necessary for all consumers in an entry/exit regime.

Question:

20.) Which particularities of the gas market, as opposed to the new switching process established for electricity, should be taken into account when designing the gas switching process?

5.6 Smart metering

The Gas Directive stipulates that member states must ensure the implementation of intelligent metering systems that assist the active participation of consumers in the gas supply market. It does not foresee blanket installation of meters that allow for remote disabling.

Pursuant to section 128 para. 2 Natural Gas Act 2011, E-Control must detail the minimum requirements of such smart meters by ordinance. The framework for the installation of such equipment must be set by the Minister by ordinance. The data to be submitted by the system operator to the supplier (and formats) in accordance with section 129 para. 2 Natural Gas Act 2011, as well as the level of detail and the format of the consumption information to be provided are subject to another ordinance to be issued by E-Control pursuant to section 129 para. 4 Natural Gas Act 2011.

The first step in this regard is a **definition of the basic requirements for smart meters**.

E-Control is of the view that smart meters must

a) comply with all statutory provisions (e.g. regarding data protection, calibration, ATEX);
b) correctly meter the quantities of gas withdrawn from the system or injected into it, under consideration of the temperature of the gas;
c) have either an analogue or a digital display at the meter that shows the current meter data;

d) in the case of meters with digital displays, save meter data and date of recording every day for a period of 60 days;

e) record meter data at 60-minute intervals, including the time and date of recording, and send them to the system operator for the purpose of providing consumption information;

f) transmit information to the system operator at least once a day, by way of equipment such as electricity meters or concentrators; the system operator must receive a day's data by noon of the following day at the latest;

g) enable exploiting data transmission synergies (e.g. for electricity, heat, water).

Question:

21.)	Are these requirements sufficient or are there additional ones that should be included?

5.7 Network service quality

Section 30 of the Natural Gas Act 2011 stipulates that the system operator's services to consumers connected to its system must meet certain safety, reliability and quality levels. The regulatory authority must verify system quality and reliability and set the applicable service and supply quality standards. To ensure that these standards are met, the regulatory authority can define compensations to be paid by system operators to the consumers concerned in the case of non-compliance. While this has so far been part of the general terms and conditions for the distribution network, the new Natural Gas Act requires E-Control to issue an ordinance concerning service and supply quality.

The current general terms and conditions for the distribution network require DSOs to send consumers information about the quality standards at least once a year. The standards are detailed and published in E-Control's relating report.[6]

Questions:

22.)	Which of the standards presented in the report are not suitable for setting service and supply quality levels?

[6] s. E-Control, *2. Monitoring Report der Qualität der Netzdienstleistung österreichischer Gasverteilernetzbetreiber für die Kalenderjahre 2009 & 2010* (Second Monitoring Report on Network Service Quality Provided by Austrian Gas Distribution System Operators in 2009 and 2010), October 2011, http://www.e-control.at/de/marktteilnehmer/gas/versorgungssicherheit/versorgungsqualitaet/qualitaet-der-netzdienstleistung (German only)

23.) Which alternative standards do you propose?

24.) Should E-Control's ordinance include a compensation and refunding mechanism for cases of non-compliance with the standards?