Bundesnetzagentur

Points of orientation - gas network tariff system (SyGNE)

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1. Introduction

The Bundesnetzagentur's Grand Ruling Chamber for Energy opened proceedings for the determination on the general gas network tariff system (SyGNE) for the period once the Gas Network Tariffs Ordinance (GasNEV) has ceased to be in effect in accordance with section 29(1) in conjunction with section 21(3) sentence 4 para 2 of the Energy Industry Act (EnWG) on 16 December 2025 [GBK-25-01-2#2]. In this determination, the Bundesnetzagentur will issue regulations before the GasNEV ceases to be in force on a general network tariff system for the gas distribution system.

This paper contains specific proposals that indicate the direction in which the Ruling Chamber is tending. These should not be understood as conclusive; rather, they reflect current findings. This paper also includes open questions that the Ruling Chamber wishes to discuss with the different stakeholder groups in the course of its decision-making process. The paper is being published for consultation. As part of this consultation, an expert dialogue is planned for 15 July 2026 in which the proposals and questions will be discussed in more depth.

Taking the results of the consultation on the points of orientation into account, the Ruling Chamber will condense its scope for options.

The Bundesnetzagentur has also commissioned a report from Consentec GmbH that analyses the different approaches in Europe to designing network tariffs, among other things. Consentec will present its initial theses at the planned expert workshop during the consultation. The final report will be used in the further steps of the proceedings.

The gas networks are facing the challenge that Germany is aiming to become climate neutral by 2045. Fossil natural gas is not climate neutral. Consequently, the gas networks will have to transform. The volumes of natural gas they carry are likely to drop considerably in the coming years.

The starting point and the developments in the gas networks are, therefore, completely different to those in the electricity networks. The electricity networks are destined to expand strongly and to remain highly relevant beyond 2045, whereas for the gas networks this is not the case. Any changes to the gas network tariff system and comparisons with the system and structure of the electricity network tariffs must always be judged with this in mind.

2. Inclusion of different network levels

Transmission network level

Thesis 1:

No network tariff system will be determined for the gas transmission system operators (TSOs) as this is already fully determined by existing determinations that primarily implement Regulation (EU) 2017/460. Existing determinations in this sector will remain. The tariff system of the gas TSOs will not change.

The methodology for calculating the tariffs for access to gas transmission networks is largely set out in European legislation. Regulation (EU) 2017/460 was implemented by Ruling Chamber 9 in the determinations “REGENT”, “AMELIE” and “MARGIT”. There is only a small amount of leeway for national regulation that is not based on Regulation (EU) 2017/460 and is affected by the CJEU judgment at all.

This leeway is at points that are not interconnection points and relates to the tariffs for non-yearly capacity, the applicable multipliers and the tariffs for interruptible capacity. Up to now, this has been regulated in accordance with the provisions of the GasNEV by the applicable “BEATE” determination. BEATE sets out that rules apply to non-interconnection points that correspond to the rules for cross-border interconnection points laid down in MARGIT. The Ruling Chamber intends to amend BEATE from 2028 onwards only if necessary. All aspects of tariff setting at the transmission network level are thus regulated.

Local distribution level

In the gas distribution system, the majority of network operators are local distribution system operators (DSOs). They currently set their tariffs in accordance with section 18 GasNEV and largely implement them by applying the “network participation model”.[1] The network operators set the parameters for application in their respective network areas differently. The setting of tariffs by local DSOs is established and there have been only isolated complaints about it. As the GasNEV is going to cease to be in effect, this network level needs to have a determination for the setting of tariffs (see below).

Regional distribution level

There are a few DSOs that have an intermediate function between TSOs and local DSOs. These “regional DSOs” set their tariffs in a similar way to the TSOs and designate capacity-based tariffs. Their tariff setting, too, has established itself without noticeable complaints. As the GasNEV is going to cease to be in effect, tariff setting rules will have to be determined in this area as well (see below).

3. Objectives of the gas network tariff system

[1] See BGW Praxisinformation P 2005/6 “Netzentgeltermittlung nach dem Netzpartizipationsmodell für Betreiber von örtlichen Gasverteilnetzen”

The gas network tariff system is intended to fulfil three objectives. It should serve to finance the gas networks, that is, to ensure that network costs are covered (cost orientation); it should be designed in such a way that the network tariffs paid by a network user reflect the costs of the network use (participation in financing), and it should be feasible (feasibility).

Cost orientation means that a network operator can earn back its costs via network tariffs. However, this does not mean that a network operator should always be able to factor all its costs into the network tariffs. Rather, it can only earn revenue on the costs that correspond to those of an efficient and structurally comparable network operator. The determinations made in the NEST process ensure that only efficient costs can be earned back.

The transformation of the gas network is likely to bring with it the future challenge that both the volumes of energy withdrawn and the annual peak load will steadily drop while the size and capability – and thus the majority of the network costs – are unlikely to reduce at the same speed. This may lead to the specific network tariffs rising sharply in the future, which could be challenging for individual network operators and their customers.

The participation in financing plays a central role in the discussion about the network tariff system. Network tariffs are cost-reflective when they reflect the costs caused by the use of the network. However, it is not usually possible to allocate costs precisely to individual network users. It is possible to approximate cost-reflective tariffs by pricing the "right" products (capacity, power and/or energy) and by differentiating between network users according to certain factors (type of network, pressure level, distance etc).

The feasibility of the network tariff system arises partly from how understandable and transparent it is. To this end, network users should be able to verify the size of the tariffs imposed (understanding of the finished product of the network tariff system). Moreover, network users should be able to comprehend the underlying system by which tariffs are set. A high degree of comprehensibility also leads to a better ability to predict the network tariffs that will have to be paid in the future.

4. Tariff system of the local DSOs

4.1 What proportion of the revenue cap should be made up of energy-based prices?

Thesis 2:

There is still a justification for energy-based prices and they will be kept.

The great majority of network costs are fixed and do not change according to the quantity of gas sent through the pipes. This is true for the capital costs and for the majority of operating costs as well. It was therefore always questionable which proportion of the total income from network tariffs should come from energy-based prices.

A commonly heard argument for energy-based prices was that they met the “subjective expectation” of most network users that more consumption would lead to higher network tariffs. Network users with the same annual peak load pay different amounts of network tariffs overall depending on the energy they withdraw. A user with a larger amount of energy withdrawn pays a larger sum in energy-based prices and thus more tariffs overall, even though the annual peak load is the same. As the sums to be paid for energy-based prices depend on the volume of gas withdrawn, they “punish” consumption, which is desirable given the damaging effect of fossil gas, at least, on the climate. The price signal should be sufficient to encourage economical behaviour.

This consideration is leading the Ruling Chamber to keep the energy-based tariffs.

In the past, it became customary for about 70% of a network operator’s revenue to come from the pricing of power and about 30% from the pricing of energy. A customer’s individual ratio of power and energy-based prices paid depends on that customer’s individual usage behaviour. The customer’s individual proportion of energy-based tariffs in the total network tariffs paid by that customer may therefore be above or below, say, 30% and above or below the proportion of the network operator’s revenues made up of energy-based tariffs.

In light of the transformation of the gas network, it is possible to consider gradually reducing the proportion of the energy-based price. The incentive to use gas sparingly will be provided more intensely from the gas consumption volume and the gas price itself.

Question 1: Is there an argument against keeping energy-based prices?
Question 2: What should be the ratio between income from power and income from energy for the network operator?
Question 3: Do you see reasons why the proportion of the network operator's income made up of energy-based prices should be greater than 30%?

4.2 Interval-metered customers: what should be priced – capacity or power?

Thesis 3:

Power-based prices will be kept. No significant advantage for capacity prices as applied in the gas transmission system can be identified in the distribution system and they would involve more work for network operators and users. Moreover, moving away from power-based prices would cause not inconsiderable costs.

This section will explore the issue of whether interval-metered customers should continue to pay a power-based price in addition to an energy-based price or whether they should pay a capacity-based price instead.

A capacity-based price is characterised by the fact that a certain amount of usage rights are acquired in advance ("booked") and the agreed price for these rights has to be paid regardless of the actual use (ie even if they are not made use of). A network user that uses more than it has acquired in advance incurs a penalty. The penalty is generally set so as to make it financially unattractive to exceed the booked capacity.

A power-based price is characterised by the fact that the user pays depending on their actual use or metered (annual peak) load without having to acquire or book usage rights in advance. The price to be paid is only determined afterwards depending on the actual use.

From the point of view of the network operator, the capacity product at the local distribution level in combination with the penalties would have the advantage of enabling the operator to estimate ahead of time which peak load the network user would withdraw as a maximum (at least as long as the penalties ensured that the network user definitely would not exceed the previously booked capacity). With power-based prices, on the other hand, the network operator cannot estimate in advance in the same way. In that case, the network user can generally withdraw gas without penalty up to the maximum extent of its connection capacity. However, unlike for the TSOs, the information about/predictability of the capacity marketing is not usually relevant for local DSOs as there is no competition for use of the individual points at the local distribution level. The consumption behaviour in the network overall is generally reliably predictable and, owing to the transformation of the gas network and the falling volumes, shortages or congestion at the local distribution level are not to be expected in future either.

Capacity-based prices have the advantage over power-based prices for the network operator that it still receives network tariffs even if the customer does not use the capacity. Capacity products thus mean predictable and reliable tariff income for network operators. With power-based prices, on the other hand, the network operator’s income only becomes clear afterwards with the actual (annual peak) load. Power-based prices thus mean less planning certainty for the network operator as far as tariff income is concerned. However, the uncertainty about the amount of tariff income is offset by the regulatory account. Switching from power-based to capacity-based prices is not necessary for a network operator to secure its income.

For network users, power-based prices have the advantage over capacity-based prices that the users do not have to think about their usage behaviour in advance and, if their load turns out to be higher than previously assumed, there are no subsequent bookings or penalties for exceeding it. If users stay under the expected peak load, they pay lower tariffs. There is nowhere near the same need for flexibility in the gas sector as the one that led to a discussion about the introduction of capacity-based prices in the electricity sector, primarily as a replacement for the flexibility-inhibiting power-based prices.

The Ruling Chamber expects that capacity-based prices (in their pure form) would cause a greater administrative burden than power-based prices and that the switch from the current power-based price system would cause additional costs. In its consideration, it has come to the conclusion that it wishes to keep power-based prices and not replace them with capacity-based prices.

Thesis 4:
It is not currently necessary to introduce tariff components that depend only on the size of the connection.

In the course of the gas network transformation, network operators will face the challenge of earning their revenue caps even while network use is decreasing. Situations could occur in which network users are connected to the network and have the ability to use it, but make use of this opportunity so rarely or not at all that they only make a small contribution to covering the revenue. To combat this, the connection owner/network user could be required to pay for part of its connection capacity/power. However, there is currently no need to introduce tariff components dependent solely on the size of the connection because no significant decline in network use has yet been observed.

Question 4: Is there an argument against keeping power-based prices for interval-metered customers?
Question 5: Do you see a need for a switch to capacity-based tariffs?
Question 6: Do you see a need to introduce tariff components independent of withdrawal and bookings that are, for example, dependent on the size of the connection?
Question 7: If you see a need to introduce tariff components solely dependent on the size of the connection sooner or later: which indicator should be used for the time of the introduction? Which factor should determine the size of the payment (eg the contractual network connection capacity or the technically available network connection capacity)?

4.3 SLP customers

Thesis 5:

The tariff system for standard load profile (SLP) customers will not be changed.

SLP customers currently pay energy-based prices that may additionally have a standing charge. Unlike interval-metered customers, SLP customers are not metered each hour; in fact, their power is not metered at all. Only the energy used is metered. Each customer is then assigned a standardised annual peak load on the basis of the metered energy using typical usage hours, regardless of whether the customer actually causes this annual peak load. There are no arguments for changing this approach and metering the actual power. To do so, all the meters of current SLP customers would have to be changed, which would take a lot of time and be expensive. Even without the approaching end to some of the gas network in the course of the gas network transformation, changing the system for SLP customers would be out of the question given the amount of work involved.

The tariff arising from the standing charge and the energy-based price is the pricing of energy added to the assigned annual peak load.[2] This method arises from the fact that individual SLP customers are assigned an annual peak load based on typical usage hours using the metered energy. The assumed annual peak load of SLP customers thus depends on the metered energy.

The possibility of a standing charge in addition to energy-based prices still makes sense since network operators retain the ability to reflect the keeping available of a certain proportion of the network in their tariffs, regardless of consumption. In light of the gas network transformation, it is also possible to consider making a standing charge compulsory in order to generate a contribution from consumers as volumes drop.

Question 8: In light of the gas network transformation, should it be compulsory for SLP customers to pay a standing charge in future?

[2] The ratio of income from energy and power corresponds to the ratio that also applies to interval-metered customers.

Question 9: Should there be specifications for the standing charge? If so, what should these be and how would you justify them?

4.4 Interval-metered customers: should non-yearly products be offered?

Thesis 6:

No short-term products will be introduced at the local distribution level as no substantial need for them is identifiable and introducing them would be hugely complex.

This discussion relates to interval-metered customers. There is no question of introducing short-term products for SLP customers as their metering and billing system is not suitable for this purpose.

It needs to be considered whether products with different durations should be offered at the local distribution level (yearly, quarterly, monthly, daily and within-day products) or whether there should be the option of reflecting a probably profiled use via non-yearly products. The current annual power-based price has to be paid for the whole year based on the load metered each hour in a year on the basis of the individually metered annual peak load, even if the network user is below it in the time after the peak load and the individual peak load is also not withdrawn at the time of the concurrent annual peak load. Network users that do not have a smooth consumption profile could be interested in products that enable profiled billing. Users with a very constant consumption profile throughout the year, on the other hand, do very well with the annual power-based price.

If non-yearly products were to be introduced, appropriate multipliers would have to be calculated and determined for the individual products. It is clear that this would involve additional effort to implement and long-term effort to settle.

From the perspective of network operators, there would be a risk that the profiled settlement/non-yearly products would bring down revenues. This could theoretically be mitigated by a premium on non-yearly products compared with the yearly product, ie the use of multipliers.

Non-yearly products are standard for the capacity tariffs at the transmission system level. Capacity products with a duration of less than a year are booked in advance depending on expected need. When yearly products are converted to non-yearly products, multipliers of between 1.1 and 2.0 are applied; the shorter the product duration, the higher the multiplier. The introduction of non-yearly products is typically linked to the introduction of capacity-based tariffs in the discussion, based on the assumption that non-yearly products can only be implemented with capacity-based tariffs. In fact, non-yearly products can be implemented with power-based prices as well.

An argument against the introduction of non-yearly products at the local distribution level is that non-yearly products would mean much greater complexity than in the current system. In any case, non-yearly products at the local distribution level only come into question for a small proportion of users, given the structure of network users. The Ruling Chamber is of the opinion that the network tariff system should not be made more complicated by introducing non-yearly products for the overwhelming majority of network users that do not use them.

4.5 How to differentiate between network users?

Thesis 7:

Local DSOs should continue to set their tariffs according to the network participation model in future.[3] The Ruling Chamber considers that this system is tried and tested.

The central factor for the gas network tariff system is what is priced (capacity, power, energy) and how network users are differentiated. “Differentiation” means that network

[3] BGW Praxisinformation P 2005/6 “Netzentgeltermittlung nach dem Netzpartizipationsmodell für Betreiber von örtlichen Gasverteilnetzen”

users pay different amounts for the unit of gas they receive depending on one or more differentiation criteria (to give an example from outside a network-based industry: in the wholesale trade a discount is often granted on the unit price depending on the amount bought).

Differentiation is possible at the local gas distribution level as well. Legally, it has so far arisen from section 18(2) sentence 2 and (6) sentence 1 GasNEV, pursuant to which the network tariffs are to be set “in a cost-reflective manner”. Potential differentiation criteria would primarily be the pressure level to which the connection owner is connected or the physical distance between the point of injection and the withdrawal point.

The pressure level has not hitherto been seen as a suitable differentiation criterion. The local distribution level is very heterogeneous, consisting of high, medium and low-pressure pipes. Although it is more often the case that large connection owners are connected to the high-pressure network and small connection owners are usually connected to the medium or low-pressure network, there are also small customers connected to the high-pressure network and larger customers connected to a medium-pressure pipe. In addition, for historical reasons, the same network operator may have some household and commercial customers connected to the medium-pressure network and others to the low-pressure network. In the past, it was not considered appropriate to have a system similar to the one used in the electricity sector in which each pressure level bears its own costs plus the costs of the upstream pressure levels. Section 18(2) sentence 1 GasNEV currently rules out making network tariffs dependent on the pressure level.

The differentiation criterion “distance between injection and withdrawal point” is not seriously being brought into the discussion at the DSO level. It has so far been ruled out in section 18(2) sentence 1 GasNEV.

Instead (almost) all network operators use the network participation model (NPM). This model prescribes dividing the local distribution level into “local transport lines” and “local distribution lines”.

Local transport lines are used by all the customers of a network. Local distribution lines are downstream of the local transport lines, serve to distribute the gas downstream to consumers and are not used by all the customers of a network. Network operators have in the past allocated pipelines using network topology features; there are no technically clear allocation characteristics.

All network users share in the costs for the local transport lines. Whether and to what extent a customer has to share in the costs of the local distribution lines via the tariffs it pays is, however, not decided based on the actual individual connection situation but rather via the “network participation function”. In the first step, it is examined whether each withdrawal point is taking gas from a local transport line or a local distribution line. Then the data sets are put in ascending order by withdrawal volume or annual peak load (with the focus on the actual connection situation). The relation between the withdrawal volume/annual peak load and use of the local distribution lines is then represented by a continuously dropping sigmoid function. This function abstracts from the actual connection situation and calculates the degree of use of the local distribution lines dependent only on the withdrawal volume and the annual peak load, with the degree of use of the local distribution lines falling as the withdrawal volume and annual peak load rise. The costs of the local distribution lines are allocated to consumers based on the degree of their use.

The result is that the greater the consumption, the lower the proportion of use of the local distribution lines and consequently the lower the contribution to the costs of the local distribution lines. The greater the consumption, the lower the costs per unit of power or energy for the user.

This means that the network participation model leads to cost/tariff degression per unit as the consumer’s consumption increases.

A key feature of the network participation model is that consumers with the same annual peak load and the same volume of gas withdrawn will pay identical amounts of tariffs regardless of where they are actually connected to the local DSO.

A further requirement is that as the consumption volume or annual peak load increases, the total amount of network tariffs to be paid also increases.

The network participation model is applied per local DSO so consumers with the same consumption behaviour at different local DSOs generally pay different tariffs.

In practice, further steps are needed to get to the tariffs listed on the price sheets but this paper will not go into more detail on these since the determination proceedings only focus on the issue of basic structural requirements and the differentiation between the network users. Each local DSO bears responsibility for producing price sheets in compliance with these rules.

Question 10: Are there reasons not to set the network tariffs independently of the actual connection situation anymore?

Question 11: Are there reasons to diverge from the application of the network participation model and, if so, what are they? Which alternative model would be preferable?

4.6 Should there be injection tariffs at the local distribution level?

Thesis 8:
No injection tariffs will be introduced at the local distribution level.

No injection tariffs are currently imposed at the local distribution level. Gas is overwhelmingly withdrawn from the local distribution level, not injected in there. If injecting gas into a network causes costs, this would generally be an argument in favour of injection tariffs (this is the justification for entry tariffs in the transmission system). However, the local DSOs have so far maintained that the introduction of injection tariffs would be associated with a great deal of work and there would only be a few producers (those injecting in biogas) that could pay them.

Biogas injection

It is basically biogas plants connected to the local distribution level that inject into it. The question of whether producers should pay injection tariffs to participate in the financing of the local distribution level may therefore essentially be reduced to the question of whether biogas producers should pay an injection tariff. The injection of biogas currently makes up a negligible proportion of all gas injected into the network in Germany, including entry at cross-border interconnection points (about 1% of German gas consumption).

It is true that this could change in the future. However, the legislature has decided on a nationwide charge to cover the additional costs of biogas plants arising from the injection (section 118(4) EnWG). This also ensures that no major cost burdens can arise for pure consumers in some regions. Moreover, Article 18(1)(a) of Regulation (EU) 2024/1789 specifies a discount of 100% for the injection of biogas at the transmission system level. The Ruling Chamber therefore takes the view that, in order to create the same conditions for the injection of biogas regardless of the network level of the injection and to avoid all biogas plants seeking a possibly inefficient connection to the transmission system, it makes sense to continue not to impose injection tariffs at the local distribution level as well.

5. Tariff system for DSOs that have capacity-based tariffs: sections 13 and 15 GasNEV

Thesis 9:

The current tariff system of DSOs with capacity-based tariffs will be continued.

DSOs with capacity-based tariffs currently set their tariffs on the basis of sections 13 to 15 GasNEV, like TSOs. Most of them apply the postage stamp reference price methodology, as the TSOs do under REGENT. Their tariff model is thus clearly different from the network tariff model for local DSOs. The Ruling Chamber sees no reason to diverge from this established method of setting tariffs.

DSOs with capacity-based tariffs tend to cover larger areas. Their networks largely consist of high-pressure pipelines and are not primarily for the purpose of supplying final consumers. In their function, therefore, they are very similar to TSOs.

The regulations relating to the pricing of non-yearly capacity, the pricing of interruptible capacity, the pricing of capacity to storage facilities and the pricing of conditional capacity that apply to TSOs should continue to be transferred to DSOs with capacity-based tariffs.

Up to now, this has been regulated through the application of the GasNEV provisions in the BEATE determination of Ruling Chamber 9. This determination is final and accepted by the market; it does not have to be included in the SyGNE process and should continue to apply from 2028 onwards.

6. Special rules for biogas: payment of tariffs for avoided network costs to biogas producers

Thesis 10:

The tariffs for avoided network costs will expire and will not be reintroduced. Shippers that already receive the tariff for avoided network costs and have not reached the end of the agreed period of ten years may continue to receive it in line with the principle of the protection of legitimate expectations until the period of ten years from initial commissioning has expired.

Section 20a GasNEV sets out that biogas shippers receive from the network operator into whose network they directly inject biogas a flat-rate tariff of €0.007 per kilowatt hour of biogas injected in for avoided network costs for a period of ten years from the commissioning of the respective network connection.

The Ruling Chamber considers it no longer objectively justifiable to maintain the tariffs for avoided network costs since the local injection of biogas does not save on network costs.

7. Special gas network tariffs

Thesis 11:

The current provisions on special network tariffs should not be continued. Already existing special network tariff agreements made under the scope of the GasNEV should not be affected by the new regulation on the grounds of the protection of legitimate expectations.

Pursuant to section 20(2) sentence 1 GasNEV, in order to avoid the construction of a direct pipeline, in individual cases DSOs may, in derogation of the provisions of section 18 GasNEV, apply a separate network tariff.

When a direct pipeline is built, a network user constructs its own connection link, usually to the upstream network level. However, as the network user is already connected to the gas network via the DSO without having its own connection link and can be supplied with natural gas accordingly, a direct pipeline would create a duplicate pipeline infrastructure. Such technically unnecessary pipeline structures are economically inefficient. They also mean that at least one existing network user leaves the community of cost bearers that previously shared the costs of the existing network infrastructure. The specific costs of the existing network infrastructure consequently rise for the remaining customers as the overall costs of this infrastructure are not likely to change significantly.

A condition for the granting of a special network tariff is that there is actually a risk of a direct pipeline construction if a special network tariff were not agreed. The network user seeking the direct line construction must prove this.

In deciding the amount of the special network tariff, the planning horizon/duration is of central importance. The lower limit for the special network tariff is set by the costs of the (fictitious) direct line. The annual costs of the (fictitious) direct line are made up of an annuity reflecting the (fictitious) capital costs based on the (fictitious) investment costs of the direct line, its (fictitious) operating costs and the upstream network costs. A duration needs to be assumed to calculate the annuity. If the requesting party is a network operator, the average useful life figures set out in Annex 1 GasNEV and KANU 2.0 are to be used as durations. For non-network operators, a shorter planning horizon of no more than 15 years is to be applied. When the special network tariff is applied for the first time, the requesting party must contractually commit to paying the special network tariff granted for the entire period assumed in the annuity.

The gas network transformation and the prospect of decommissioning or converting the local distribution level means that the remaining time period for the use of a (fictitious) direct line will continue to reduce. This would make building such a line increasingly unattractive, including because of the earlier planning phases. The duration of use that could realistically be used to calculate the annuity would get shorter and shorter, meaning that the tariff for the (fictitious) direct line would get higher and higher. It will therefore become increasingly unrealistic that the requesting party would actually accomplish a direct line construction. It will also become increasingly unrealistic that the party would want to commit to paying a special network tariff for a period lasting several years if it expects to have to look for an alternative to fossil natural gas.

On the other hand, as the total number of gas network customers gets smaller, the tariffs for the remaining users of the existing network infrastructure will rise continually. This means that the incentive to leave the community of cost-bearing network users to escape the rising network tariffs, at the expense of the remaining network customers, may get larger. This would exacerbate the effect of rising network tariffs for remaining network users.

To keep as many customers as possible in the community of cost bearers and because there is hardly any serious risk of an economically inefficient direct pipeline construction, the possibility of granting special network tariffs should not be continued.

8. Cost centre accounting: sections 11 and 12 GasNEV

Thesis 12:

The compulsory provisions on cost centre accounting will be reduced to the minimum necessary to apply and understand the tariff model.

A network operator's cost centre accounting has to show the (final) cost centres needed to apply and understand the tariff model (eg the (final) cost centres of local transport lines and local distribution lines in the network participation model) and additionally the (final) cost centres of metering and meter operation. This is to ensure that the tariff setting and the network tariffs set out in the price sheet are understandable at this level. In other respects, the cost centres needed to allocate costs to the (final) cost centres may be freely selected under general business principles. The principles of consistency and comprehensibility are to be upheld despite the permitted degree of freedom. The cost centre accounting and any changes to the classifications are to be documented and conducted in such a way that a competent third party could understand them. The documentation and the cost centre accounting must be presented to the Bundesnetzagentur upon request.