Schweizerische Eidgenossenschaft
Confédération suisse
Confederazione Svizzera
Confederaziun svizra

Federal Department of the Environment, Transport, Energy and Communications DETEC

Federal Office of Energy SFOE
Renewable energies

Report dated October 22, 2025

Study on management fees

Development of a new method for calculating the management fee within the framework of the feed-in tariff system

This is a machine-translated version of a study originally published in German. The original is available at neon.energy/bewirtschaftungsentgelt

Neon Neue Energieökonomik GmbH

Date: October 22, 2025

Location: Bern

Client:

Swiss Federal Office of Energy (SFOE)
CH-3003 Bern
www.bfe.admin.ch

Contractor:

Neon Neue Energieökonomik GmbH
Schönleinstrasse 31
D-10967 Berlin

Authors:

Ingmar Schlecht (schlecht@neon.energy)
Vlada Maksimova (maksimova@neon.energy)
Alexander Neef (neef@neon.energy)

The authors of this report are solely responsible for its content and conclusions.

Swiss Federal Office of Energy SFOE
Pulverstrasse 13, CH-3063 Ittigen; Postal address: Swiss Federal Office of Energy SFOE, CH-3003 Bern
Tel. +41 58 462 56 11 · Fax +41 58 463 25 00 · contact@bfe.admin.ch · www.bfe.admin.ch

Table of contents

Abbreviations and definitions

AB	Plant operator
AEP	Balancing energy price
BG	Balancing group
D-1 forecast	Feed-in forecast based on the previous day's feed-in
DA price	Day-ahead electricity price for the Swiss bidding zone
KVA	Waste incineration plant
Price delta	Balancing energy price minus day-ahead price
Forecast error	Difference between forecast and actual feed-in
RZ	Control area
Trivial forecast	Feed-in forecast that can be regarded as the minimum standard for forecast accuracy

Summary

Motivation. Swissgrid has announced that, as of January 1, 2026, it will change the mechanism for calculating the balancing energy price from the previous two-price model to a single-price model. This will eliminate the distinction between short and long prices in favor of a uniform balancing energy price per quarter hour. This fundamental change has a direct impact on the calculation logic of the variable part of the management fee: the previous formula, which was based on the difference between the monthly averages of the short and long prices, would structurally result in zero in the single-price system and would therefore no longer accurately reflect the variable cost shares of all technologies. A methodological realignment is therefore necessary in order to put plants in direct marketing on an equal footing with feed-in tariffs.

This study. In this study, we analyze the consequences of the changeover for plants in direct marketing and examine, on a technology-specific basis, how the new single-price AEP system affects the balancing energy costs of the various technologies. Based on this, we are developing a new, robust, and transparent methodology for calculating the variable portion of the management fee from 2026 onwards.

Changes due to AEP conversion. The central incentive in balance group management is shifting fundamentally as a result of the conversion to the single-price AEP system: individual deviations are no longer automatically penalized as a flat rate compared to the day-ahead price; instead, the balancing energy price specifically penalizes behavior that burdens or relieves the control area. Deviations that benefit the control area are priced symmetrically to behavior that stresses the control area. As a result, in the case of uncorrelated, unsystematic forecast errors, the long-term expected value of balancing energy costs in the single-price system is zero; systematic costs only arise if forecast errors for a technology occur simultaneously and in the same direction and correlate with the control area balance or high balancing energy prices.

Management fee in the single-price AEP. Our evaluation shows that for hydropower, biomass, waste, and wind, no systematic balancing energy costs arise in the expected value; in the periods considered, negative values (revenues) even predominate as a result of system-supporting deviations. The situation is different for photovoltaics: weather-induced forecast errors in the same direction, which affect many plants at the same time, correlate with the control zone balance and high balancing energy prices, which means that systematic balancing energy costs are also to be expected in the future. Accordingly, we recommend setting the variable portion of the management fee to zero for non-PV technologies and maintaining the fixed marketing amount (0.11 Rp./kWh). For PV, we recommend setting the variable portion on a quarterly basis using empirically determined balancing energy costs in the new pricing model. To determine these, we recommend deriving simplified forecast deviations from the previous day's feed-in values and correcting the costs calculated in this way using a constant factor to reflect the forecast quality of a professional forecast.

Résumé exécutif

Motivation. Swissgrid a annoncé qu'à partir du 1er janvier 2026, le mécanisme de calcul du prix de l'énergie d'ajustement passera du modèle à deux prix au modèle à un seul prix. Ainsi disparaît la distinction entre prix « short » et prix « long » au profit d'un prix unique d'énergie d'ajustement par quart d'heure. Ce changement fondamental a un effet direct sur la logique de calcul de la partie variable de l'indemnité de gestion : la formule actuelle, basée sur la différence des moyennes mensuelles des prix « short » et « long », donnerait structurellement zéro dans le système à un prix unique et ne refléterait donc plus correctement les parts de coûts variables de toutes les technologies. Une réorientation méthodologique est dès lors nécessaire pour assurer l'égalité de traitement entre les installations en commercialisation directe et celles bénéficiant de la rétribution à prix coûtant.

Cette étude. Dans cette étude, nous analysons les conséquences du passage au modèle à un prix unique pour les installations en commercialisation directe et examinons, technologie par technologie, l'impact du nouveau système de prix unique de l'énergie d'ajustement (AEP) sur les coûts d'ajustement. Sur cette base, nous développons une nouvelle méthodologie robuste et transparente pour le calcul de la part variable de l'indemnité de gestion à partir de 2026.

Changements liés à la réforme de l'AEP. L'incitation centrale dans la gestion des groupes-bilan se modifie en profondeur avec l'introduction du système AEP à un prix unique : ce n'est plus chaque écart individuel qui est systématiquement pénalisé par rapport au prix Day-Ahead, mais le prix de l'énergie d'ajustement valorise de manière ciblée les comportements qui chargent ou soulagent la zone de réglage. Les écarts favorables à la zone sont tarifés de façon symétrique aux écarts qui la stressent. Il en résulte que, pour des erreurs de prévision non corrélées et non systématiques, la valeur attendue à long terme des coûts d'ajustement est nulle dans le système à prix unique ; des coûts systématiques n'apparaissent que lorsque les erreurs de prévision d'une technologie surviennent simultanément, dans la même direction, et corrèlent avec le solde de la zone de réglage ou avec des prix d'énergie d'ajustement élevés.

Indemnité de gestion dans le système AEP à un prix. Nos analyses montrent que, pour l'hydroélectricité, la biomasse, l'incinération des déchets et l'éolien, il n'existe pas de coûts d'ajustement systématiques en valeur attendue ; pour les périodes considérées, on observe même des valeurs négatives (recettes), dues à des écarts favorables au système. Il en va autrement pour le photovoltaïque : des erreurs de prévision alignées, induites par la météo et affectant simultanément de nombreuses installations, sont corrélées avec le solde de la zone de réglage et avec des prix d'énergie d'ajustement élevés, de sorte que des coûts d'ajustement systématiques continueront à apparaître. Nous recommandons donc de fixer la part variable de l'indemnité de gestion à zéro pour les technologies non photovoltaïques et de maintenir le montant fixe de commercialisation (0,11 ct./kWh). Pour le photovoltaïque, nous proposons de déterminer trimestriellement la part variable sur la base des coûts d'ajustement empiriques observés dans le nouveau système à un prix. Pour les calculer, nous suggérons de dériver des écarts de prévision simplifiés à partir des valeurs d'injection de la veille, puis de corriger ces coûts par un facteur constant reflétant la précision d'une prévision professionnelle.

1 Introduction

Background. The Swiss electricity market design aims to integrate renewable energies (RE) into the market. An important instrument for this is direct marketing, which was introduced in 2018 and allows operators of RE plants to place their electricity on the market independently or with the help of a direct marketer. To prevent operators from being disadvantaged compared to the reference market price, they are supported by a management fee. This compensates for the additional costs associated with direct marketing, in particular for forecasting, schedule management, trading connections, billing, and balancing energy.

Management fee. The management fee consists of a fixed portion that covers administrative and ongoing marketing costs, as well as a variable portion based on balancing energy costs. Originally, the management fee was set at a flat rate based on historical balancing energy prices (AEP). However, with the sharp rise in balancing energy costs, particularly in 2022, it became clear that the methodology used at the time was no longer adequate. An initial adjustment was therefore made in 2023: since then, the variable portion of the management fee has been indexed monthly and dynamically adjusted based on current balancing energy prices.

Upcoming change. In view of the change in the balancing energy price mechanism to a single-price model from 2026 announced by Swissgrid (2025), there is now a renewed need for action. The introduction of this new model replaces the previous distinction between short and long prices with a uniform AEP. This fundamental change has a direct impact on the basis for calculating the management fee. This means that the basis for calculating the variable portion of the management fee needs to be fundamentally revised. A new methodology must be able to reflect the costs of balancing energy under the conditions of the single-price model in an appropriate, comprehensible, and reliable manner. At the same time, it must be designed in such a way that it can react flexibly to changing market conditions while ensuring transparency and simplicity.

This study. The aim of this study is to develop a new, robust, and transparent methodology for calculating the variable portion of the management fee from 2026 onwards. The focus is on a system that meets the requirements of the future single-price model, is based on current market data, and enables consistent, comprehensible indexing of variable cost components. To make the change transparent, we first explain the current methodology and show why it cannot be continued unchanged in the single-price system. We then outline the differences between single-price and dual-price AEP and finally derive the formula for the management fee that we recommend for use from 2026 onwards.

2 Existing methodology in the two-price model

In this chapter, we describe and analyze the methodology for calculating the management fee in accordance with Art. 26 of the Energy Promotion Ordinance (EnFV) as of September 2025. The methodology defined there is based on the two-price model valid until December 31, 2025.

Calculation formula. With the introduction of the direct marketing model in 2018, a management fee was introduced to cover the costs of direct marketing for plants in the feed-in tariff system that have switched to direct marketing. Since April 1, 2023, the management fee has been set monthly and consists of a fixed portion and a variable portion. The variable portion is indexed based on balancing energy prices. Indexation is relative to the 2013–2015 reference period, during which the technology-specific variable direct marketing costs (referred to as "variable costs" in the formula) were originally derived. Since then, the management fee in Rp./kWh has been calculated as

$$BewirtEntgelt_{Monat} = Fixbetrag + \left(Variable\ Kosten_{Energiequelle} * \frac{AE\ Kosten_{Monat}}{AE\ Kosten_{2013-2015}}\right).$$

The fixed amount covers constant marketing expenses such as exchange fees or administrative costs for the balance group (BG). The monthly differentiation of the variable portion allows the balancing energy costs, some of which have been highly volatile since the energy crisis, to be reflected. The energy source-dependent variable direct marketing costs reflect the varying quality of forecasts: while there is a high degree of uncertainty in forecasts for wind and PV plants, controllable technologies such as biomass or waste-to-energy plants are much easier to predict. Since any forecasting errors in the previous two-price AEP system resulted in costs, this method was appropriate for the two-price system.

Balancing energy costs. The balancing energy costs included in the formula are calculated from the difference between the short and long balancing energy prices averaged over all quarter-hours of the month, divided by two:

$$AE\ Kosten_{Monat} = \frac{(Short\ Preis_{Mittelwert} - Long\ Preis_{Mittelwert})}{2}.$$

With the switch to the single-price system, this difference no longer applies, as there is now only one balancing energy price per quarter hour. The above term would therefore no longer provide a meaningful representation of the balancing energy costs; it would always result in zero.

Existing amounts.Figure1 shows the variable portion of the management fee since the beginning of 2023. The introduction of indexation and a further sharp increase from spring 2024 onwards, which is due to rising balancing energy prices, are clearly evident. This illustrates the logic of the current methodology with an increase factor: the fee for all technologies increases when the AEPs rise. This makes sense in the two-price model because higher AEP levels are typically associated with higher balancing energy costs, especially for technologies that are more difficult to forecast, such as wind and solar.

Management fee 2023–2025, variable portion

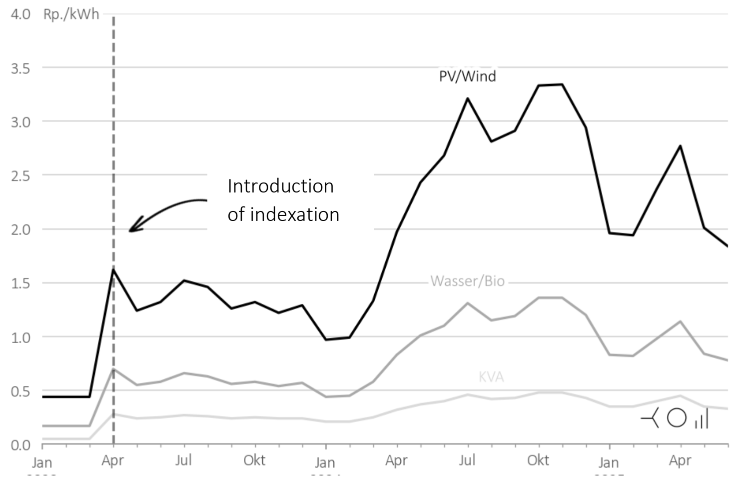


Figure1 : Time series of the variable component for different technologies.

Payments in 2024. The total volume of management fees paid out in 2024 amounted to CHF 34.7 million. The portfolio of plants that are directly marketed is dominated by hydropower in terms of energy volume. The share of management fee payments to hydropower plants is correspondingly high. Biomass, PV, and wind follow at a considerable distance. Payments to waste incineration plants are significantly lower.

3 From a two-price to a single-price model: system utility instead of schedule adherence

In this chapter, we explain the difference between a single-price and a dual-price AEP and show how the incentive structures are changing. We also show why the changeover also has an impact on balancing energy costs.

3.1 COMPARISON OF INCENTIVES

Changeover on January 1, 2026. With the introduction of the single-price model for balancing energy (Swissgrid, 2025), the distinction between short and long prices per quarter hour will be eliminated. While the previous two-price model primarily rewarded schedule adherence and penalized any deviation relative to the day-ahead (DA) market, the single-price model creates incentives for behavior that benefits the system: balance groups are rewarded for supporting the control area balance – and they pay if they burden it.

Single-price model. In the single-price model, deviations that are beneficial to the control area are rewarded symmetrically with the same price as behavior that stresses the control area is penalized, instead of penalizing both in general. This boosts economic efficiency, smooths the system balance, reduces the demand for control energy, and supports operational system security because more control power remains available for unexpected events.

Two-price model. For comparison: In the two-price model, two balancing energy prices apply: one for covered and one for uncovered BGs. Any deviation is therefore systematically disadvantageous compared to the DA price.Table1 shows the difference between the single-price and two-price models using the example of a short situation in a quarter of an hour.

Table1 : Example of the effect of the two pricing models for a quarter of an hour in which the system is undercovered.

Example	Two-price model (until the end of 2025)	Single-price model (from the beginning of 2026)
Balancing group short	BG pays 200 EUR/MWh	BG pays 200 EUR/MWh
Balancing group long	BG receives 60 EUR/MWh	BG receives 200 EUR/MWh

3.2 CONTROL AREA BALANCE AND DEMAND FOR CONTROL ENERGY

Impact on balancing energy costs. The change is not just a technical detail, but shifts the expected values of balancing energy costs: In the case of random forecast errors, the long-term expected value of balancing energy costs in the pricing model is zero (the positive and negative contributions offset each other in the medium term). In contrast, costs remain in the expected value only if the forecast errors are systematically correlated with the price delta between the AEP and DA price, as we explain in more detail in section4.1 .

Price delta. The price delta between AEP and DA price is particularly high when the balancing zone is severely unbalanced and there is high demand for balancing energy. In this case, a large amount of expensive balancing energy must be activated, the costs of which are passed on by Swissgrid to the BG. The key question is therefore what mechanisms trigger large control area deviations. To answer this, we will consider three cases below, which are illustrated in Figure2 REF _Ref209604810 \h .

Deviation of the control area balance

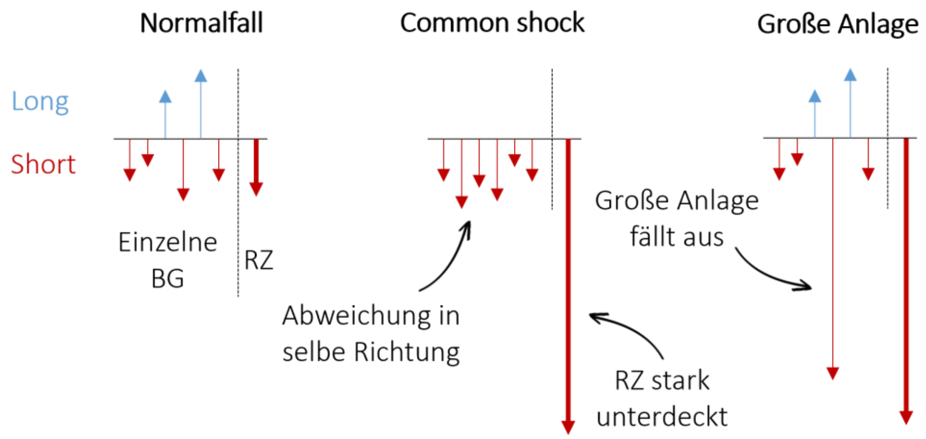


Figure2 : Normal case of small deviations vs. two possible reasons leading to a large deviation of the total RZ. In normal cases, the deviations of individual BG point in different directions and the RZ is only slightly unbalanced. In the event of a common shock, the deviation of many BG points in the same direction. This leads to a significantly undercovered RZ. If a large plant fails, for example a nuclear power plant, this alone can lead to a significantly unbalanced RZ.

Normal case. Balancing groups are required to report schedules with quarter-hourly forecasts of planned generation and consumption to the transmission system operator. In reality, however, deviations from the schedule occur. This may be due to the failure of a plant or because less electricity is consumed than forecast. However, the reason for the deviation is normally different for each BG, so that the deviations of different BGs are independent of each other. If you add up the deviations of all BGs, you get the RZ balance, which is low under normal conditions.

Common shock. The situation is different in the case of common shocks, which drive many BGs in the same direction at the same time (simultaneously short or simultaneously long). In such situations, numerous individual deviations add up to a highly unbalanced control area. In Switzerland, unexpected weather changes (e.g., thunderstorm fronts, rapid cloud cover) can be a driver for such common shocks.

Large plant. Another situation that can lead to a high DC balance is the failure of a single large plant. If, for example, a nuclear power plant fails, a large part of Switzerland's power supply is temporarily lost and the entire DC is short.

4 New methodology in the pricing model

The single-price model requires an adjustment to the formula for calculating the management fee. Even with the new formula, the management fee should continue to cover not only the fixed marketing costs but also the average costs incurred by the demand for balancing energy. In this chapter, we first explain the theoretical basis of balancing energy costs in the single-price system and then present the calculation logic in detail.

4.1 Origin of balancing energy costs in the single-price system

Changeover. As explained in the chapter "2 ," the variable part of the management fee was previously calculated from the difference between the monthly averages of the short and long prices. This logic only works in the two-price system. In the single-price system, a uniform AEP applies every quarter hour; the difference *between short and long* is eliminated and the previous term would be structurally zero. Plants would then only be left with the fixed amount.

Balancing costs. Conceptually, technology-related balancing energy costs in the single-price system can be formulated as products of forecast deviations and the difference between the AEP and DA price, summed over time. In a single-price system, there is no longer a systematic portfolio effect: the aggregation of many individual plants reduces the variance but does not change the expected value of the costs. The average cost of many individual plants thus corresponds to the average cost for all plants as a whole. For a given technology, the following applies for the quarter-hour$t$ and the billing period$T$ (e.g., a quarter):

$$\text{Prognoseabweichung}_t[\text{MWh}] = \text{Prognose}_t\text{ -Realisierung}_t$$

$$\text{Kumulierte AE Kosten}_T[€] = \ \textstyle\sum_{t\in T} \text{Prognoseabweichung}_t\text{*}(\text{AEP}_t\text{-DA}_t).$$

No systematic costs. In the new pricing system, the price delta only has an effect where there are systematic correlations between forecast deviations and price conditions; otherwise, positive and negative terms average out in the expected value, so that no systematic costs are incurred. This means that balancing energy costs are only incurred in the expected value if the forecast deviations for the respective plant type are systematically correlated with the price delta between the AEP and DA price. For unsystematic deviations, no balancing energy costs are now incurred in the expected value.

Specific balancing energy costs. A specific cost indicator in Rp./kWh is then obtained by normalizing with the amount of energy fed in and a monthly EUR/CHF conversion:

$$\text{Spezif. AE Kosten[Rp./kWh]} = \frac{\text{Kumulierte AE Kosten}_t\text{*EUR\_CHF\_Faktor}_{\text{Monat}}}{\text{Eingespeiste Energie}}$$

4.2 PRELIMINARY CONSIDERATIONS : TECHNOLOGY DIFFERENCES

Basic mechanism. To understand how the pricing model affects the balancing energy costs of different technologies, it is necessary to consider the underlying mechanism that leads to systematic costs. Systematic balancing energy costs arise in the pricing model when forecast errors for a technology occur simultaneously and in the same direction and correlate with the control zone balance or with the price delta between the AEP and DA price. They also occur when individual plants are so large that they significantly influence the control zone balance on their own (see section3.2). Since the plants in direct marketing are small (the majority of plants are < 10 MW), random individual deviations are not sufficient to shift the control zone balance significantly. In practice, systematic costs therefore require a common forecast error among many small plants ("common shock") – for example, a large-scale change in weather conditions – which influences the electricity generation of many plants in the same direction at the same time.

PV. With the strong expansion of PV, there are now hours when more than half of Switzerland's electricity generation comes from solar power plants. The actual feed-in from these plants depends directly on the current solar radiation. Whether the forecast for the energy fed into the grid is correct therefore depends on the accuracy of the weather forecast for PV. Although these are becoming increasingly accurate, they remain imperfect despite advances. If, for example, a thunderstorm front arrives earlier than expected, the PV feed-in is often lower than forecast over a large area. Such sudden and difficult-to-predict weather changes are typical common shocks that lead to a highly unbalanced system balance. The crucial point is that many PV systems in Switzerland are affected at the same time, and the deviation of a single system is therefore related to the deviation of the entire control area. Since in such situations the price delta between AEP and DA price is also large and systematically has the opposite sign to the forecast error, PV systems systematically incur costs for balancing energy.

Wind. Wind energy accounts for a small share of total electricity generation in Switzerland. In 2024, it was less than 1% (Pronovo). Although, as with PV, the weather forecast has a significant impact on the accuracy of wind energy forecasts, there are no systematic balancing energy costs. The reason for this is that the aggregated wind forecast errors are too small to substantially change the system balance for Switzerland as a whole due to the low installed capacity. The forecast error for wind therefore happens to point in the same or opposite direction as the system balance. As a result, there are no systematic costs for balancing energy in the expected value.

Water. Hydropower generation is primarily determined by hydrological drivers (precipitation, snowmelt) with a certain time lag (ranging from hours to weeks). It can usually be predicted accurately using hydrological runoff models and is therefore not directly dependent on short-term weather changes. Hydropower accounts for a large proportion of Switzerland's total electricity generation during many hours of the year, but it differs fundamentally from PV: large hydropower plants are controllable, while the expansion of PV consists mainly of many small plants that cannot be remotely controlled . The operation of large hydropower plants can be specifically adjusted, particularly in the event of precipitation or rapidly changing inflows. This avoids parallel deviations and limits the impact on the control zone balance despite high installed capacity. In the case of small, non-remote-controlled run-of-river power plants, deviations are typically driven by local hydrological conditions and are not systematically correlated with the control zone balance. Forecast errors occur throughout the year, mainly at plant level (e.g., technical malfunctions), and do not represent a common shock; they are therefore largely uncorrelated with the system balance. In addition, storage and pumped storage plants can be used to benefit the system. In the single-price model, the combination of good predictability, high controllability, and system-friendly operation means that hydropower does not incur any systematic balancing energy costs in terms of expected value. What remains is primarily dispersion risk, but not a permanently positive cost level.

Waste incineration and biomass. Thermal power generation plants, such as waste incineration plants and biomass plants, account for a relatively small share of total electricity generation in Switzerland and are generally predictable. Deviations therefore arise mainly at the plant level (e.g., due to technical defects) and are not related to the control zone balance. They sometimes happen to point in the same direction and sometimes in the opposite direction. Overall, therefore, there are no systematic balancing energy costs in the expected value in the single-price system; primarily, the dispersion risk remains.

4.3 Calculation of balancing energy costs in the single-price system

Time series on prices, forecasts, and feed-in are central to the calculation of balancing energy costs.

AEP and DA price. Quarter-hourly AEP and day-ahead prices are required to calculate balancing energy costs. Both time series are published and are generally accessible. Until the Swiss DA market has switched to quarter-hourly resolution, the corresponding hourly DA prices can be used for this purpose. For the years 2023 and 2024, Swissgrid has provided synthetic AEP time series based on the demand for balancing energy and the bids submitted, using a pricing model logic. On this basis, we have calculated the potential balancing energy costs for these years as part of this project in order to derive and validate the new calculation logic for the management fee.

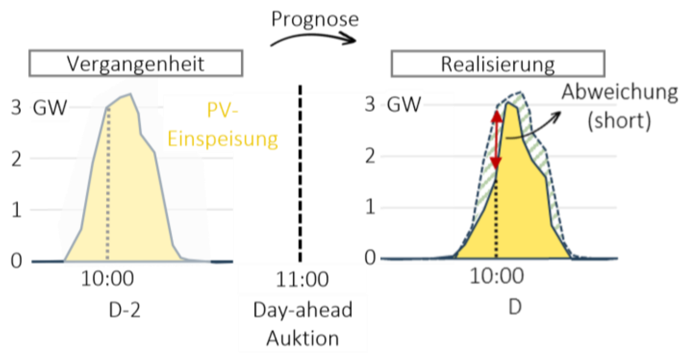
Forecast deviation. The actual forecast data used for individual technologies is *not* publicly available in a usable form because:

- Balancing groups report schedules across portfolios (often multiple technologies): BG schedules do not allow direct conclusions to be drawn about technology-specific forecast errors.
- No incentive for disclosure: There is no obligation to disclose.

The forecast data must therefore come from other sources.

Trivial forecast. A forecast that any data processor is capable of making is a trivial D-2 forecast, in which the feed-in on day D-2 before gate closure of the day-ahead auction is taken as the forecast for the 24 hours on the day of realization (D). We refer to this reference as a trivial forecast. In reality, the forecasts are significantly better because they are based on current weather forecasts, for example. The forecast error resulting from the trivial forecast can therefore be seen as the upper limit of the balancing energy costs. InFigure3 , the trivial forecast is illustrated using the example of PV and a calculation example is given to show how this results in the balancing energy costs in a quarter of an hour.

Trivial forecast – an example



Time window	10:00-10:15
Realization	2.0 GW
Forecast	3.0 GW
Deviation	-250 MWh
DA price	50 €/MWh
AEP	150 €/MWh
AE costs	€25,000

Figure3 : How the trivial forecast works, using PV as an example, and a calculation example for the quarter-hourly balancing energy costs incurred. The information available at the DA auction at 11 a.m. on the previous day (D-2) about solar feed-in across Switzerland serves as a forecast for the next day (D). Balancing costs arise, for example, between 10:00 and 10:15 a.m. on the day of realization (D) because the missing energy must be purchased at the higher AEP.

Forecast quality. For the years 2023–2024, there is a high degree of consistency between the trivial forecast and actual generation for water, biomass, and waste incineration. As explained above, short-term weather changes have less of a direct impact here than, for example, in the case of PV.

Specific balancing energy costs. Based on the trivial forecast, the calculated specific balancing energy costs for wind, water, biomass, and waste in 2023–2024 are predominantly negative values. In the single-price system, this means revenue instead of costs. Even with this "simple" reference forecast, the expected value shows no systematic balancing energy costs for the technologies mentioned; this confirms the preliminary considerations in section4.2 . The results are shown inFigure4 . In the years examined, for which Swissgrid provided feed-in AEP time series, even with a trivial forecast, wind would have generated additional revenue rather than costs due to forecast errors. Such revenue usually occurs when forecast errors point in the opposite direction to the Swiss control area balance, meaning that they have a system-supporting effect. The revenues for wind underscore that, due to the low installed wind capacity in Switzerland ( ), wind energy is not a significant driver of Switzerland's overall control area balance and no systematic balancing energy costs are to be expected for wind.

Specific balancing energy costs based on the trivial forecast

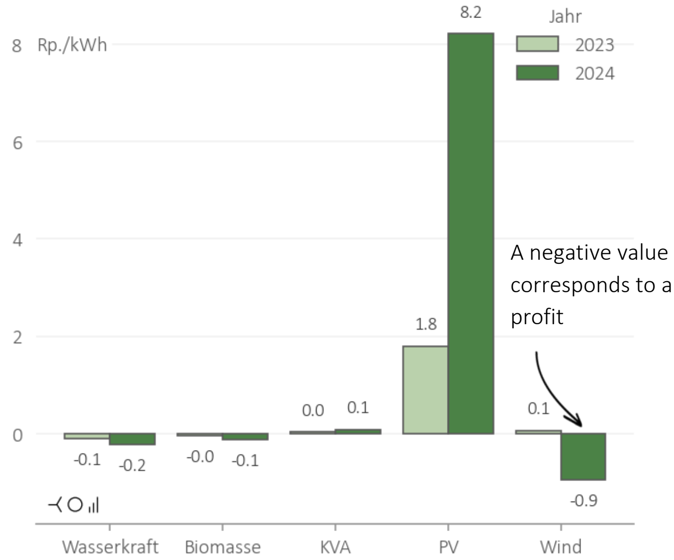


Figure4 : Specific balancing energy costs calculated using the trivial forecast for the years 2023-24. Negative values are revenues from forecast errors, which the new feed-in AEP always rewards when they counteract the imbalance of the entire Swiss control area.

Specific balancing energy costs for PV. The situation is different for PV. Due to parallel, weather-induced forecast errors and the associated correlation with the control area situation, systematic AE costs arise in the pricing system. We have calculated the specific AE costs for PV twice: with trivial forecasts and with professional forecasts. The necessary consistent feed-in and forecast time series come from BG Erneuerbare Energien and its meteorological service provider. The comparison shows that professional forecasts significantly reduce AE costs, but do not eliminate the basic cost level because the structural correlation remains. The relationship between trivial and professional forecasts determined in this way serves as a correction factor in the subsequent formula derivation. The results are summarized inFigure5 .

Specific balancing energy costs for PV in comparison

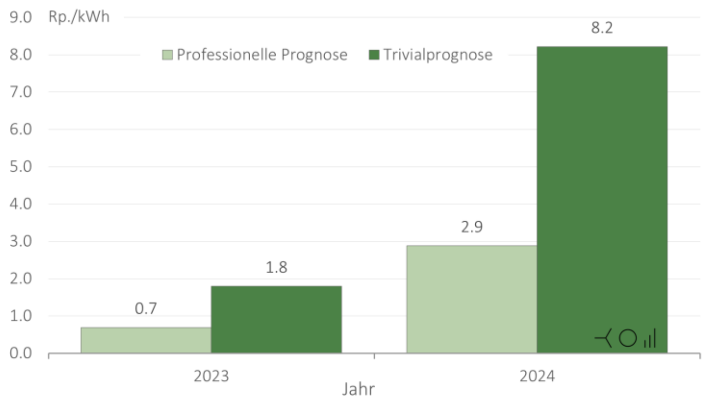


Figure5 : Specific balancing energy costs for PV based on the trivial forecast and a professional forecast for the years 2023 and 2024.

4.4 Recommendation for a new formula

Payment formula. We recommend that the payment for a plant operator (PO) who is entitled to the management fee be calculated as before from the energy fed into the grid, multiplied by the sum of a technology-independent fixed component and a technology-dependent variable component.

$$\text{Auszahlung}_{\text{AB}} = \text{Eingespeiste Energie}_{\text{AB}} * \left(\text{Fixer Anteil} + \text{Variabler Anteil}_{\text{technologie}}\right)$$

The fixed component could remain unchanged from the original methodology, as the introduction of the single-price system does not lead to any relevant changes in the cost components it covers. An analysis of the appropriateness of this cost component was not part of this study. It currently stands at:

$$\text{Fixer Anteil} = 0{,}11\ \text{Rp./kWh}$$

Variable component non-PV. Based on the analysis in section4.3 , we recommend setting the variable component of the management fee for all non-PV technologies, i.e., hydropower, biomass, waste, and wind, to zero. This corresponds to the technology-specific average costs for balancing energy in the new single-price model, because such forecast deviations, which are not systematically correlated with the price delta, no longer have any balancing energy costs in the new system in terms of expected value. For these technologies, therefore, no adjustment to the method of calculating the management fee would be necessary, as even in the old formula, the result for the variable part would always have been zero with the switch to the single-price system.

$$\text{Variabler Anteil}_{\text{nicht-pv}} = 0$$

Variable share of PV. Of the relevant technologies, systematic costs for balancing energy are only to be expected for PV in the future. For solar energy, the variable share should therefore be derived directly from the technology-specific average costs for balancing energy. Several steps are necessary to calculate this. The Swiss-wide feed-in time series for PV, calculated by Pronovo, is used as a basis. In the first step, the nationwide costs that would arise if all operators used the previous day's (D-1) generation to forecast their generation are calculated on a quarterly basis.

> Box: Trivial forecast and D-1 forecast. In the section "4.3 ," we calculated the balancing energy costs using the trivial forecast. The trivial forecast can be assumed to be the minimum level of forecast accuracy and uses knowledge about the feed-in *before gate closure* of the DA auction. Notwithstanding this, we recommend using the D-1 forecast to calculate the management fee. This consists of the feed-in for the previous 24 hours and therefore contains information that is not yet available for the DA auction. The D-1 forecast also reduces the margin of fluctuation in the calculated AE costs and makes the payment of the management fee more predictable.

This is used to calculate the forecast deviation first.

$$\text{Prognoseabweichung}_t = \text{Realisierung}_{t_{D\text{-}1}}\text{-Realisierung}_t$$

The balancing energy costs can then be calculated for the time intervalt as:

$$\text{AE Kosten (D-1 Prognose)}_t = \text{Prognoseabweichung}_t{}^*(\text{AEP}_t\text{-DA}_t).$$

The abbreviations in brackets represent the balancing energy price (AEP) and the day-ahead price (DA) for the control and bidding zones in Switzerland, respectively.

The costs for a quarter are then added up:

$$\text{AE Kosten (D-1 Prognose)}_{\text{quartal}} = \sum\nolimits_{t\in\text{quartal}} \text{AE Kosten (D-1 Prognose)}_t.$$

In the second step, the costs incurred per quarter are divided by the electricity generated from PV in the same period. This gives the average balancing energy costs in a quarter based on the D-1 forecast.

$$\text{Spezifische AE Kosten (D-1 Prognose)}_{\text{quartal}} = \frac{\text{AE Kosten (D-1 Prognose)}_{\text{quartal}}}{\text{Stromerzeugung}_{\text{quartal}}}$$

In the final step, the average costs that would be incurred with a D-1 forecast are adjusted using a correction factor. In our study, this correction factor was calculated and rounded down based on the ratio between the balancing energy costs for the D-1 forecast and the balancing energy costs of a professional forecast for 2023 and 2024. Quarterly correction factors are shown inFigure6 . The professional forecasts for this period come from the meteorological service provider of the Renewable Energies Balance Group.

$$\text{Korrekturfaktor} = \frac{\text{AE Kosten D-1 Prognose}_{2023\text{-}24}}{\text{AE Kosten professionelle Prognose}_{2023\text{-}24}} \approx 2{,}5$$

Quarterly correction factors 2023-24

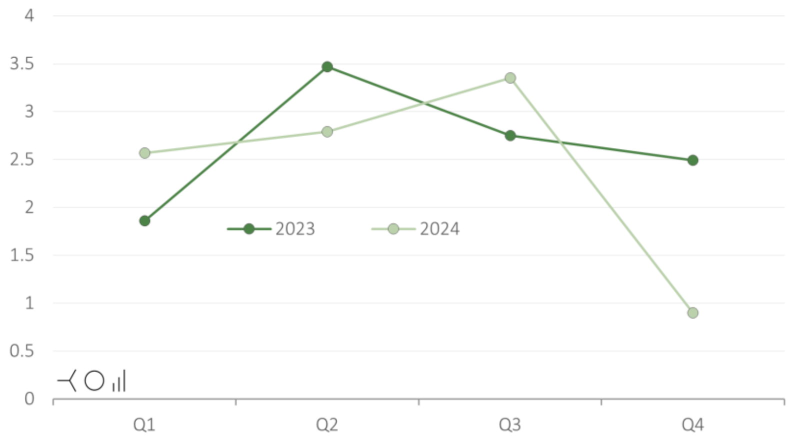


Figure6 : The correction factor over time for the quarters of 2023-24. Despite different cost levels, the correction factor remains largely stable between the two years. For 2023, it is 2.63, and for 2024, it is 2.51. Unlike in Figure 5, the D-1 forecast was used to calculate the present values rather than the trivial forecast, as we also propose this calculation method (D-1) for the new formula.

Taken together, the variable share for solar energy is

$$\text{Variabler Anteil}_{\text{quartal}} = \frac{\text{Spezifische AE Kosten (D-1 Prognose)}_{\text{quartal}}}{\text{Korrekturfaktor}}.$$

The variable portion should be calculated on a quarterly basis in order to better compensate for minor fluctuations within quarters. The compensation energy costs and electricity generation change from quarter to quarter, while the correction factor remains unchanged. We also recommend evaluating the correction factor after two years and recalculating it if necessary, using the best possible PV forecast available at that time.

4.5 QUANTITATIVE COMPARISON

In this section, we compare hypothetical management fees and payments between the old and proposed new methodologies, using the synthetic feed-in AEP time series for 2023 and 2024 provided by Swissgrid for the calculations of the new methodology.

Comparison of both formulas. InFigure7 , we compare the management fee for PV in 2024 according to the new and old methodologies. The figures show (i) the management fee actually applied in the two-price system, averaged over the respective quarter, and (ii) the hypothetical management fee that would have resulted in the single-price system using the new calculation formula (based on Swissgrid's synthetically recalculated AEP). The comparison shows how the system logic (two-price vs. single-price model) affects the result.

Management fee for PV in comparison

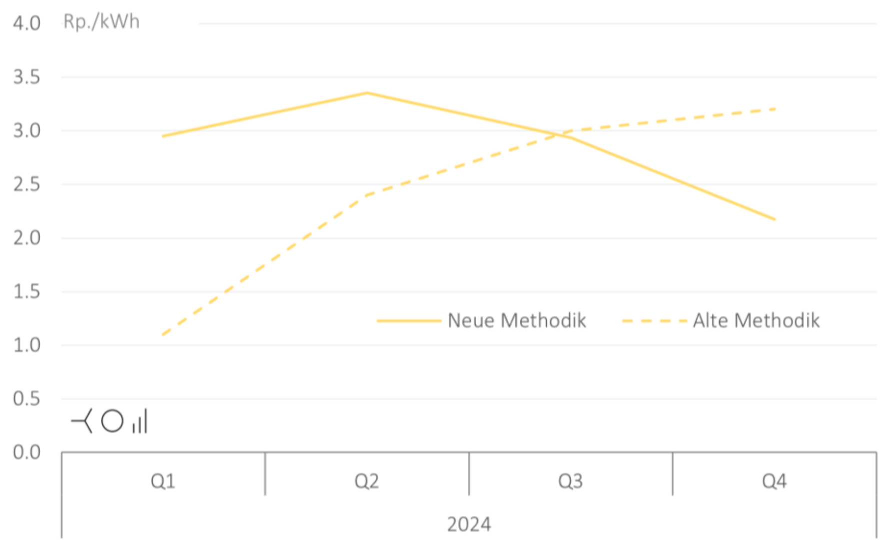


Figure7 : Temporal progression of the management fee for PV in the new and old methodologies for the year 2024, applied to the AEP time series corresponding to each methodology, i.e., two-price AEP for the old methodology and single-price AEP for the new methodology. For better comparability, the monthly values of the old methodology were averaged for each quarter.

Payments in the single-price system. Applying the single-price system and the new calculation formula would reduce expenditure: payments of the hypothetical management fee determined on the basis of the synthetic single-price AEP would amount to CHF 9.3 million, which is approximately 70% less than the status quo.

Payments in 2024 in comparison

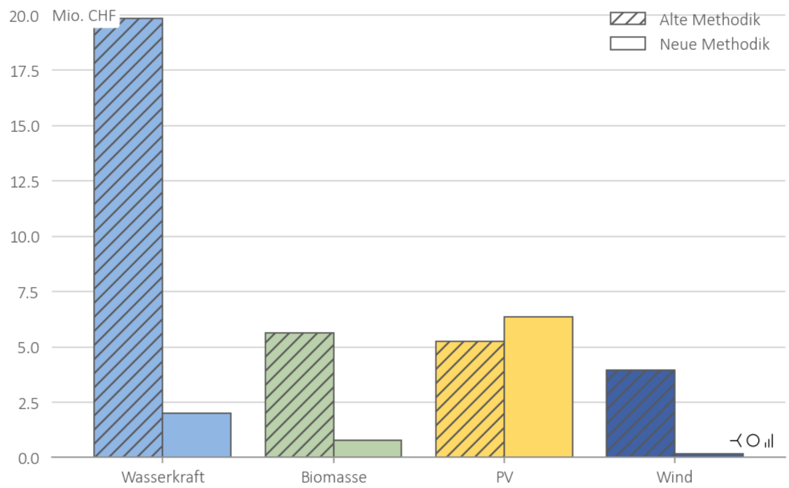


Figure8 : Actual management fee payments in 2024 compared with payments under the new methodology. In both cases, the total payment, i.e., variable plus fixed portion, is shown.

5 Recommendations

Zero remuneration for non-PV. We recommend zero remuneration for hydropower, biomass, waste, and wind, as their forecast errors are not systematically correlated with the price delta. In the single-price system, this means that there are no expected balancing energy costs for these technologies. This would eliminate the need to calculate the variable portion of the management fee on a monthly/quarterly basis for these technologies; the fixed amount for marketing costs (0.11 Rp/kWh) remains unaffected by this and was not examined in this study. For the periods available to us with synthetic price-in AEP, a simple forecast based on previous day's generation values even shows frequent profits from forecast errors. Such profits always occur when forecast errors point in the opposite direction to the Swiss control area balance, meaning that they have a system-supporting effect.

Variable share for PV. Of the relevant technologies, systematic costs for balancing energy are only to be expected for PV in the future. We therefore recommend that the variable component of the management fee in Rp./kWh for this technology be derived quarterly on a uniform basis throughout Switzerland as follows:

$$\text{Variabler Anteil}_{\text{quartal}} = \frac{\text{AE Kosten (D-1 Prognose)}_{\text{quartal}}}{\text{Stromerzeugung}_{\text{quartal}}} * \frac{1}{\text{Korrekturfaktor}}.$$

We recommend using the D-1 forecast error time series as a conservative basis for calculating balancing energy costs and scaling the resulting values with a correction factor of 2.5 to market-standard professional forecast quality. The forecast errors are evaluated every quarter hour using the price difference between AEP and DA and then normalized to Rp./kWh.

Further development. We recommend reviewing the correction factor every two years and recalibrating it using the best available professional PV forecast data at that time.

References

Swissgrid (2025). New pricing mechanism for balancing energy from 2026. https://www.swissgrid.ch/de/home/newsroom/newsfeed/20250328-01.html

Pronovo (2024). Data on wind power generation. https://pronovo.ch/downloads/Lastgangprofile_nach_Technologien/