Just Energy Transition in Coal Regions

September 2025

CASE STUDY

Impact of Thermal Flexibility on the Operational Performance of Chile's Power System

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Introduction

Power systems are changing and becoming more complex. They are moving from systems dominated by large thermal or hydro power plants to ones that include a multitude of resources and generation technologies of varying sizes. The energy transformation implies a change of:

- Firm to variable energy sources.
- Synchronous generation to inverter-based resources.
- Generation resources' location.
- A centralized generation system to a more decentralized one.
- Passive to active consumers.

A variety of interdependent technical and operational needs must be always met to maintain a safe and reliable electricity system. Grid stability is fundamental to the electricity supply security and the VRE integration. The Chilean system is no exception, where the high integration of variable renewable energies (VRE) poses new challenges to its reliability.

The challenge is to continuously meet the growing needs of power systems, which involves maintaining a balance between supply and demand, as well as consistently providing essential voltage and frequency management services. In addition, sufficient reserves must be ensured so that the power system remains resilient to unexpected events and within its operational design limits.

Traditionally, most of these ancillary services have been provided by thermal power plants – and other synchronous technologies – as a byproduct of electricity generation. However, as variable renewable energy sources such as wind and solar are integrated into the system, fewer synchronous generators are dispatched based on economic merit. As a result, system operators are often forced to keep some thermal power plants online solely to maintain system security and reliability, even when their electricity output is not required. This is currently the case in northern Chile, where there are insufficient low-emission assets capable of providing frequency or voltage control. Consequently, thermal plants must remain in operation, not for their energy, but for the essential ancillary services they provide.

It is important to have assets capable of providing security and reliability to the power system, especially with high integration of variable renewable energy (VRE) and increasing decarbonization targets. However, developing and building new assets is complex and time-consuming. The need for these services must be assessed, properly dimensioned, tendered, and then followed by the construction phase. For this reason, the flexibilization of existing thermal assets emerges as a cost-efficient short-term alternative to support decarbonization and the integration of further VRE into the system. Flexibilization is achieved through an operating mode in which the power plant follows load and VRE output, adjusting its generation between its technical minimum load and maximum capacity as needed.

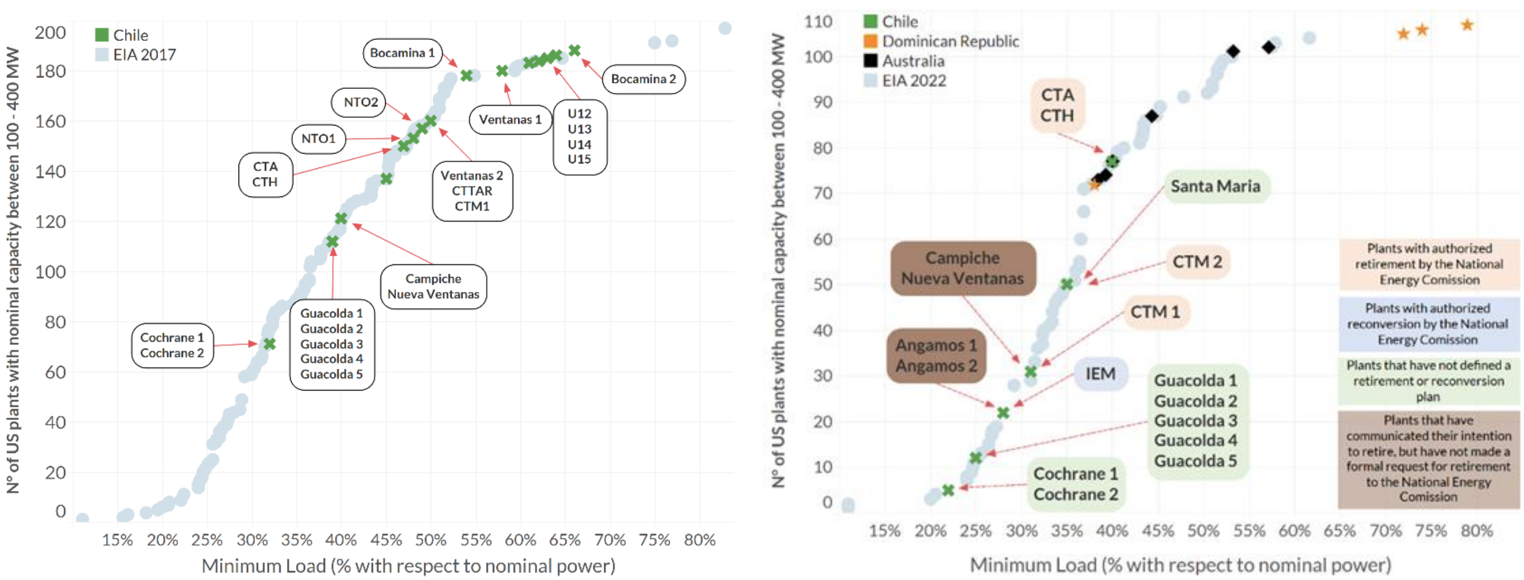
The flexibility alternative does not imply the immediate closure of thermal power plants but proposes keeping them in operation at minimum levels while the system is not yet prepared for their full retirement. This involves improving the plants' flexibility parameters, such as minimum load and minimum up/down times. This approach enables the integration of more renewable energy without compromising system security, while also reducing both costs and emissions.

This alternative should not be seen as a substitute for long-term coal phase-out, but rather as a set of transitional measures that enable a gradual shift while providing the necessary time to implement other enabling conditions necessary for long-term decarbonization. It serves as an initial step, allowing thermal power plants to be either retired or repurposed in later stages, once the system is better prepared. Moreover, the cost of reducing the minimum load (ML) of a coal-fired power plant ranges between USD 0.5 million and USD 2 million per unit, depending on the complexity of the measures required.

In Chile, thermal power plants have made significant efforts to reduce their ML values in recent years. Currently, these are among the lowest in the world. However, this study evaluates the effects of further reducing ML values. Figure 1 presents the cumulative number of coal-fired power plants in the U.S. (vertical axis) versus their minimum load as a percentage of their nominal power (horizontal axis). These coal-fired units are represented by light blue dots; in addition, coal-fired units in Chile (green crosses), Australia (black diamonds) and the Dominican Republic (orange stars) are incorporated. Chilean plants have a high operational flexibility (low ML value) compared to thermal units in other countries.

Figure 1: Accumulated Number of Coal Plants in the U.S. by Minimum Load and Comparison with Other Markets (Chile[1], Australia and the Dominican Republic) in 2017 and 2024.

Source: Own elaboration.



2017 2024

In Chile, Cochrane and Guacolda power plants units' ML are the result of a review process that has allowed them to be reduced. The strategy of reducing the minimum load is crucial in contexts where thermal units are still needed to support the system during the energy transition.

The objective of this study is to assess the impact of further reducing the ML of coal and gas-fired power plants in Chile's electricity system by 2027. Lowering ML allows these units to reduce daytime operation without shutting down entirely, enabling them to resume generation during peak demand—primarily at night—while continuing to provide essential system services. The first chapter outlines the three ML scenarios. Subsequent sections analyze and compare generation, curtailment, system costs, and emissions (both global and local), concluding with a summary of findings.

[1] After the date of the study, the Guacolda 5 unit reduced its ML to 30 MW, equivalent to 19% of its installed capacity on March 7th, 2025.

Evaluated scenarios

This study analyzes the behavior of the Chilean electricity system in response to a decrease in the minimum load of coal and gas thermal units. The operation of the system is modeled using PLEXOS under three ML scenarios of coal and gas units by 2027. All other parameters[2] are held constants for all scenarios. The three ML scenarios evaluated are defined as follows:

1. **BAU**: considers actual ML values for coal-fired (Figure 1) and gas units.
2. **Intermediate**: considers an average reduction in the ML of coal-fired units. It includes the implementation of boiler combustion adjustments and operation with a minimum of two pulverizers for all plants. ML values are assumed to range between 20% and 28% of the plants' nominal capacity, depending on their progress in ML reduction and other technical parameters. For gas-fired plants, current ML values are maintained.
3. **Aggressive**: this scenario involves a change in the operating philosophy of coal-fired power plants, with a reduction in ML that entails continuous operation with only one pulverizer across all plants. ML is reduced to 17% of their nominal capacity for all units. In the case of gas-fired plants, their design ML values are considered, and ML values driven by limits set in environmental regulation are removed. Existing environmental regulation limits the capacity to lower ML further of gas-fired generation due to the concentration of nitrogen oxides (NO_X) in the flue gas emissions when operating at low loads.[3]

Table 1 presents coal and gas installed capacity in the system as of 2027 and their aggregated ML values, in each scenario.

[2] Fuel costs, additional capacity installation, demand, among others.

[3] Historically, international emission limits for power plants were defined in terms of the concentration of pollutants in the flue gas, not the actual emissions to the atmosphere. In a context where plants operated constantly, the concentration of pollutants in the flue gas was directly proportional to the emission of pollutants into the atmosphere. However, this is no longer the case; plants now operate in a more variable and flexible manner, with different operational levels throughout the day. Measuring pollutant concentration in the flue gas is no longer sufficient to quantify the actual pollutant emissions to the atmosphere. Actual emissions are determined by the concentration of the pollutant in the flue gas (mass of the pollutant in a volume of air), multiplied by the rate at which the flue gas exits the facility, or the gas flow rate (volume of air per unit time).

Table 1: Installed capacity and ML in each modelling scenario by technology.[4]

Source: Own elaboration.

TECHNOLOGY	*SYSTEM'S INSTALLED CAPACITY 2027 (MW)*	*BAU ML (%)*	*INTERMEDIATE ML (%)*	*AGRESSIVE ML (%)*
COAL[5]	*2,789*	*27.4%*	*24.0%*	*17.0%*
GAS[6]	*5,006*	*49.4%*	*49.4%*	*29.6%*

The performance of the system under different **hydrological conditions** is analyzed in the scenarios evaluated. When hydrological conditions are dry, the system is more stressed and depends to a greater extent on thermal power plants. In contrast, during the years with abundant hydro resources, the need for thermal power plants decreases. However, even during years with abundant hydro resources, in Chile it is **necessary to resort to thermal dispatch,** especially between January and June, when snowmelt begins to decrease, and the rainy season has not yet started.

Generation and curtailment analysis

Chile has seen significant integration of Variable Renewable Energy (VRE) in recent years. Currently, the installed capacity is 11.1 GW of solar, 4.7 GW of wind, and 1 GW of BESS. This capacity is expected to continue to grow rapidly in the future. VRE has increasingly replaced thermal generation, which remains crucial mainly during the night hours when solar generation is unavailable. However, as more BESS is integrated, the need for thermal generation during the night will start to decrease.

A rapid installation of solar, wind, and BESS is projected in the coming years, reaching 15.9 GW of solar, 8.2 GW of wind, and 4.0 GW of BESS by 2027. This will lead to a decline in the dispatch of thermal generation. However, the dispatch of thermal generation remains highly dependent on hydrological conditions[7]: drier years require significantly more thermal generation than wetter ones (Figure 2). The proportion of coal and gas generation will depend on the relative prices of each fuel.

[4] The values presented are aggregated for all coal and gas units in the system, but the modeling considered values for each unit according to its technical parameters.

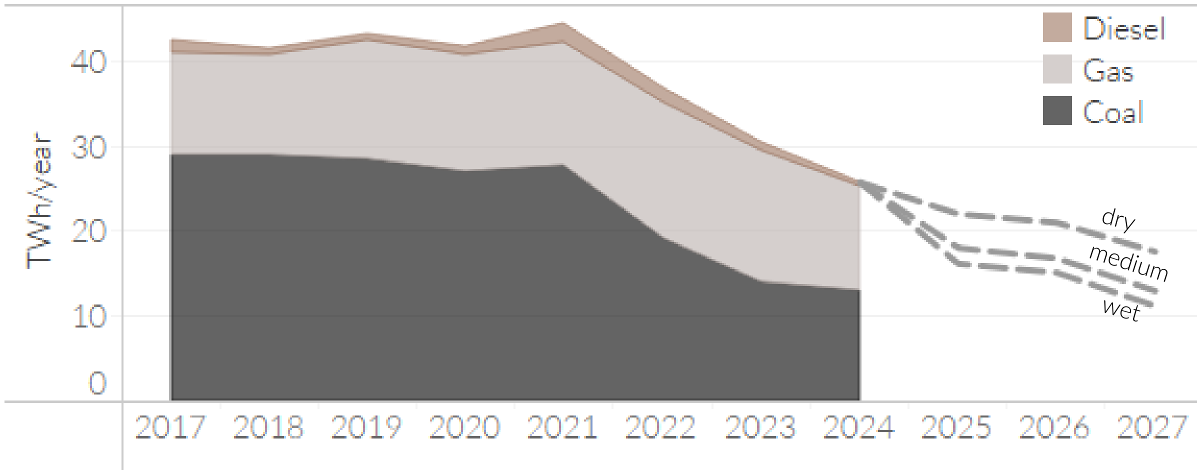
[5] Considers 12 electrical system plants which are not reconverted or have an approved decommission by 2027.

[6] Considers the 22 main electrical Chilean system plants.

[7] There are other factors affecting thermal generation that are not evaluated, such as safety constraints.

Figure 2: Historical (until 2024) and projected thermal generation for three hydrological conditions (dry, medium and wet).

Source: Own elaboration.

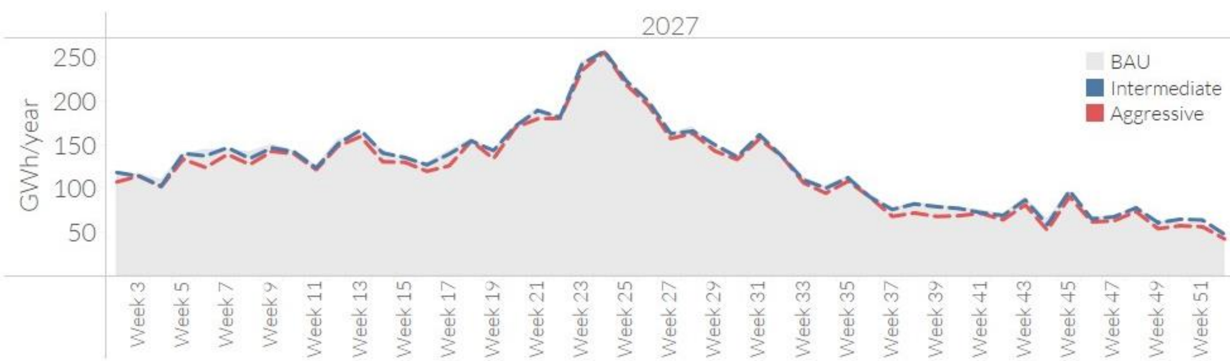


Although thermal generation is expected to decline in Chile's energy mix, lowering the ML of thermal assets could further reduce their contribution, particularly during daytime hours. Under median hydrological conditions in the BAU scenario, thermal generation (coal, gas, and diesel) is projected to reach 13,002 GWh in 2027. In the Intermediate ML scenario, this figure decreases by 0.8%, reaching 12,902 GWh. In the Aggressive ML scenario, the reduction is significantly greater, as it involves a deeper ML reduction, including gas-fired plants. In this case, thermal generation decreases by 5.2% compared to BAU, reaching 12,330 GWh in 2027.

A seasonal analysis of thermal generation shows that the greatest difference between the scenarios occurs during the summer and spring months (week 38 to 11) (Figure 3).

Figure 3: Thermal generation (coal, gas and diesel) in a medium hydrological condition in 2027.

Source: Own elaboration.



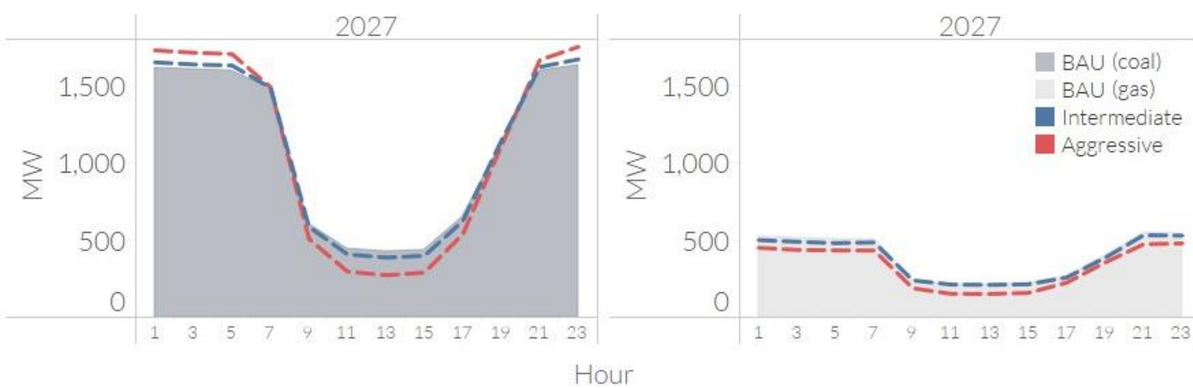
During autumn and winter (weeks 12 to 37), reducing the minimum load of thermal power plants has limited effect, as these units are still required to meet system demand. Solar generation is lower during these months due to shorter daylight hours, and hydro output is also reduced because most reservoirs rely on snowmelt, which increases in spring. Consequently, thermal units must operate above their minimum load levels, which reduces the relevance of ML flexibility during this period.

During the melting season, reducing ML becomes far more important, as both hydro and solar generation increase significantly during this period. The excess of solar and hydro generation during the day results in daytime energy surpluses, limiting the need for thermal generation to nighttime hours or for providing ancillary services and maintaining system security. Therefore, the ability to reduce thermal generation to lower levels during the day becomes a key strategy to avoid unnecessary curtailment of renewable energy, lower operational costs, and achieve emission reductions—while still ensuring the reliability of the electricity system, particularly during wet years.

On an hourly basis, thermal generation will primarily operate at night, when other resources are limited. During the day, thermal power plants will either shut down or operate at their minimum load levels (Figure 4).

Figure 4: Hourly dispatch for coal (left) and gas (right) in a medium hydrological condition.

Source: Own elaboration.

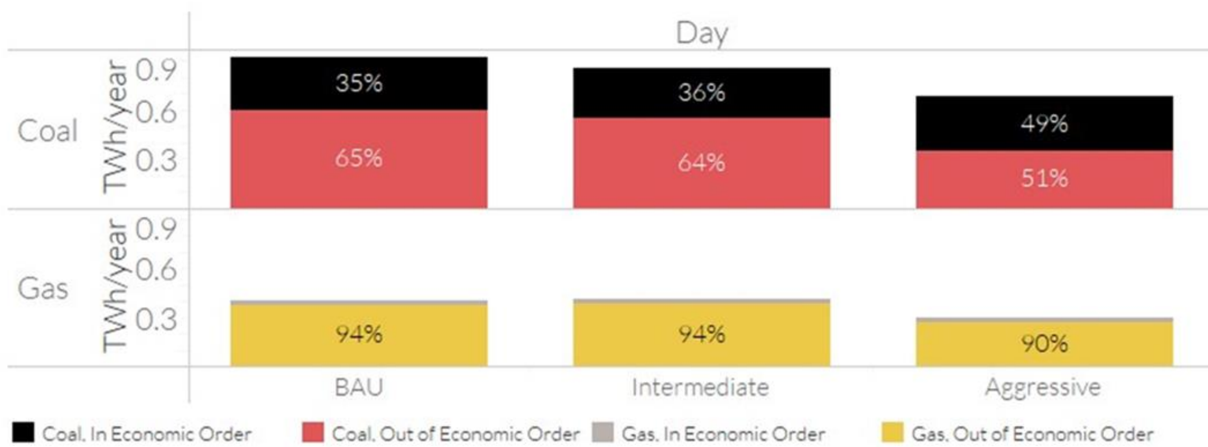


Comparing the three scenarios, in 2027 there is an average reduction in daytime coal generation (between 9 AM and 5 PM) when coal power plants operate with increased flexibility. This trend is most pronounced in the Aggressive ML scenario, where coal dispatch is reduced by 16–36% compared to the BAU scenario, depending on the hour of the day. Gas generation decreases to a lesser extent, primarily because gas power plants are inherently more flexible—they can start up and shut down much faster than coal units and typically operate in a cycling mode[8]. However, in the Aggressive ML scenario, daytime gas generation sees a reduction of 15–29% compared to BAU, depending on the time of day.

Although the impact of reducing ML on overall thermal dispatch is moderate, the reduction in out-of-merit dispatch is significant. Out-of-merit thermal generation occurs mainly during daytime hours. In 2027, under medium hydrological conditions, coal-fired power plants are expected to generate 921 GWh during the day, with 65% of this being out-of-merit dispatch. In the Intermediate ML scenario, daytime coal generation decreases to 857 GWh, with 64% out-of-merit. The impact is even more pronounced in the Aggressive ML scenario, where coal generation drops to 685 GWh, and only 51% is dispatched out of merit.

Figure 5: Average daily thermal generation by merit order in 2027 (medium hydrological condition).

Source: Own elaboration.



Under the same hydrological conditions, out-of-merit gas generation during daytime decreases from 94% to 90% when comparing the BAU and Aggressive ML scenarios, with total daytime generation falling from 403 GWh to 300 GWh.

When analyzing how out-of-merit dispatch changes under different hydrological conditions, a similar pattern is observed. In 2027, under wet hydrological conditions, daytime coal generation in the BAU scenario reaches 765 GWh, 75% of which corresponds to out-of-merit dispatch. In the Aggressive ML scenario, daytime coal generation drops to 542 GWh, with the share of out-of-merit dispatch decreasing to 59%. In a dry hydrological scenario for the same year, daytime coal

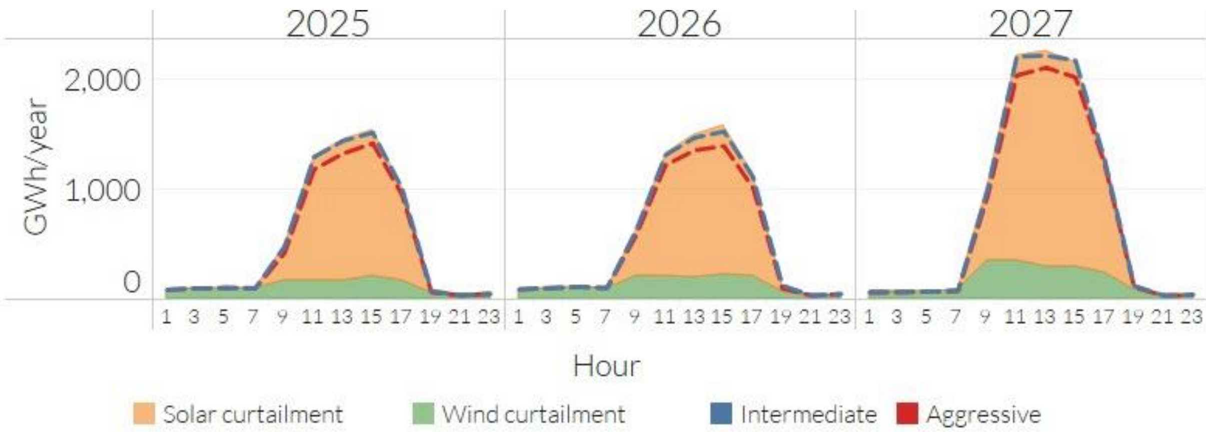
[8] In situations where gas-fired units must operate during the day outside of the economic dispatch order—such as for system security reasons—lowering their minimum load offers a valuable opportunity to reduce out-of-merit gas dispatch, particularly during daytime hours.

generation in the BAU case is higher, reaching 1,108 GWh, but only 61% of that generation is out-of-merit. In the Aggressive ML scenario, coal generation decreases to 833 GWh, and the share of out-of-merit dispatch falls further to 46%.

Reducing thermal generation during the day allows for greater integration of renewable energy, thereby decreasing curtailment. In 2027, under medium hydrological conditions and the BAU scenario, renewable curtailment is expected to reach 9.4 TWh. This figure increases to 10.5 TWh in a wet year. However, reducing the minimum load of coal and gas power plants leads to a decrease in curtailment across all hydrological conditions and scenarios (Figure 6).

Figure 6: Average annual projected curtailment by hour under medium hydrological conditions.

Source: Own elaboration.



In 2027, under medium hydrological conditions, the Aggressive ML scenario avoids 632 GWh of renewable curtailment compared to the BAU scenario. In the Intermediate ML scenario, the impact is more moderate, with 76 GWh of curtailment avoided. This difference is explained by the smaller reduction in minimum load in the Intermediate ML scenario compared to the Aggressive ML scenario.

Cost analysis

Marginal costs (MgC) are expected to follow the same pattern observed in recent years, with lower prices during daytime hours. In the BAU scenario and under medium hydrological conditions, average daytime MgC are projected to be 17.4 USD/MWh by 2027, increasing to 22.9 USD/MWh in a dry year. In contrast, during nighttime hours, average MgC are expected to reach 59.9 USD/MWh under medium hydrological conditions and 69.1 USD/MWh in dry hydrological conditions.

Reducing the minimum load of thermal power plants slightly increases the average marginal cost during daytime hours, as curtailment is reduced and, consequently, there are fewer hours with zero marginal cost. This increase is minor, averaging less than 1 USD/MWh. At night, marginal costs slightly decrease because more economical —and now more flexible— plants can replace more expensive units. In the Aggressive ML scenario, the average nighttime marginal cost in 2027 decreases by approximately 1.5 USD/MWh compared to the BAU scenario (Figure 7).

Figure 7: Hourly average MgC in medium hydrological conditions.

Source: Own elaboration.

At certain hours, additional support and ancillary services are required beyond mere energy provision. In such cases, the optimal economic dispatch[9] is not sufficient to maintain secure operating limits—especially in areas with high penetration of inverter-based generation. As a result, thermal power plants must be dispatched out of merit order to ensure system security. The uncovered costs of these out-of-merit generators are compensated as an additional cost, which is allocated proportionally among all market participants withdrawing energy from the system during those hours. Some of these costs are related to the provision of ancillary services, while others arise from system needs that cannot be met through optimal dispatch alone.

In 2019, these side payments were low—around 0.3 USD/MWh—and did not represent a major concern for participants in the Chilean electricity market (Figure 8). However, starting in 2020, they have shown a progressive increase. In 2022 and 2023, the average costs reached 11.6 USD/MWh and 10.3 USD/MWh, respectively. On a monthly basis, January 2023 saw a peak in system costs, averaging 16.9 USD/MWh[10].

[9] Without considering inertia, voltage control, frequency regulation, and adequacy.

[10] Small distributed generators in Chile may opt into a special remuneration regime, funded through side payments. These administrative costs are specific to the Chilean market and have been excluded from this analysis.

Figure 8: Historical average monthly side payments.

Source: Own elaboration based on Coordinador Eléctrico Nacional (CEN) data

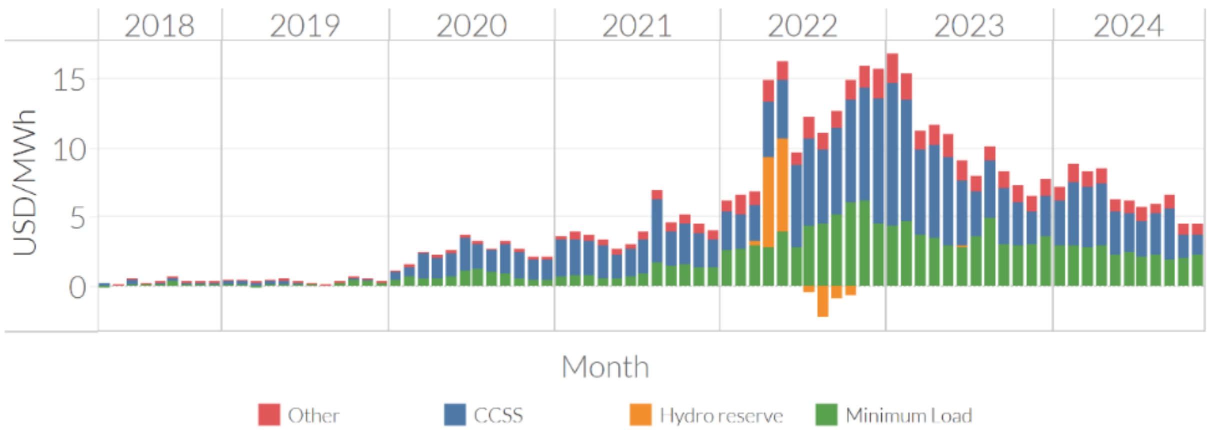
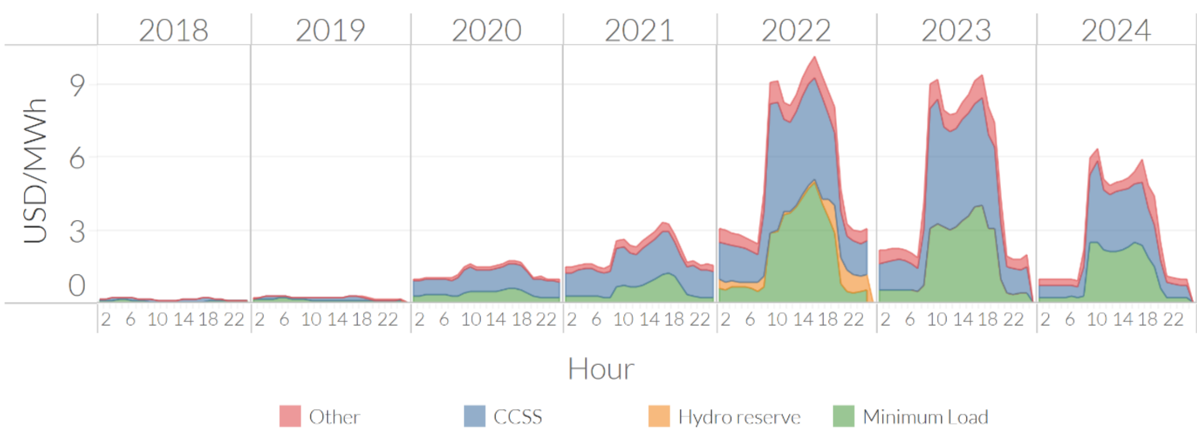


Figure 9: Historical average hourly side payments.

Source: Own elaboration based on NEC data.



This rise in sidepayments in Chile's electricity market has been driven by a combination of factors, including operational inflexibilities of thermal and hydroelectric units, security constraints, assets available to provide reserves, higher fuel prices, and operational and programming practices (Figure 9).

By 2027, the expected average price for side payments in the BAU scenario is 3.5 USD/MWh under medium hydrological conditions (Figure 10). However, in September, this is expected to be around 3.0 USD/MWh, while in January it is closer to 4.0 USD/MWh. Under drier hydrological conditions, side payments decrease due to the increased need for thermal generation, reaching an annual average value of 3.3 USD/MWh. In a wet year, these would average 3.9 USD/MWh.

The most significant side payment is due to operation at minimum load, which is expected to average 1.3 USD/MWh by 2027 under medium hydrological conditions in the BAU scenario. However, this cost is higher during the summer months, reaching monthly values between 1.4 and 1.9 USD/MWh.

Figure 10: Expected monthly sidepayments in the BAU scenario by 2027.

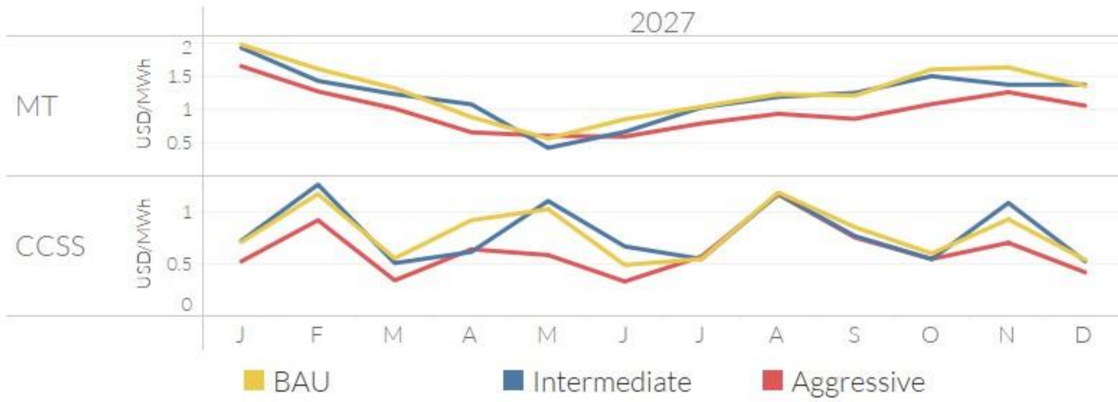
Source: Own elaboration.

By further increasing the flexibility of gas and coal units, side payments decline. Under medium hydrological conditions, the average total side payment in 2027 is nearly the same for the BAU and Intermediate ML scenario but falls sharply under the Aggressive ML scenario—from 3.5 to 2.9 USD/MWh. This 0.6 USD/MWh reduction is driven largely by a 0.3 USD/MWh drop in minimum-load side payments and a 0.2 USD/MWh drop in ancillary service payments (Figure 11).

Minimum-load side payments are seasonal, declining in autumn when both hydro and solar generation decrease, and thermal plants are dispatched more based on economic merit. The greatest benefit of ML reduction occurs in summer: with abundant renewable generation, lowering the ML lets thermal plants run at a minimal secure level, cutting side payments significantly.

Figure 11: Comparison of average monthly sidepayments due to operation at minimum load and ancillary service under medium hydrological conditions.

Source: Own elaboration



In 2027, the Aggressive ML scenario also shows a marked reduction in ancillary service side payments. This occurs because diesel units that provided frequency up-regulation control [11] under the BAU and Intermediate ML scenarios are replaced by gas-fired plants in the Aggressive case. Lowering the minimum load of gas units allows more plants to operate simultaneously, however each unit runs at lower output levels. This approach increases their available capacity for upward frequency regulation. As a result, gas turbines replace the more expensive diesel units that previously provided this service, leading to a reduction in ancillary service side payments.

Emissions analysis

Under medium hydrological conditions, annual carbon dioxide (CO_2) emissions in 2027 reach 11,420 ktonCO2 in the BAU scenario. The lower thermal generation in both the Intermediate ML and Aggressive ML scenarios, drives emissions lower: to 11,411 ktonCO2 in the former (a 0.1% reduction) and to 11,230 ktonCO2 in the latter (a 1.7% reduction). For the same period under wet hydrological conditions, annual emissions decrease from 9,976 ktonCO2 in the BAU scenario to 9,970 ktonCO2 in the Intermediate ML scenario (a 0.1% reduction) and to 9,731 ktonCO2 in the Aggressive ML scenario (a 2.5% reduction).

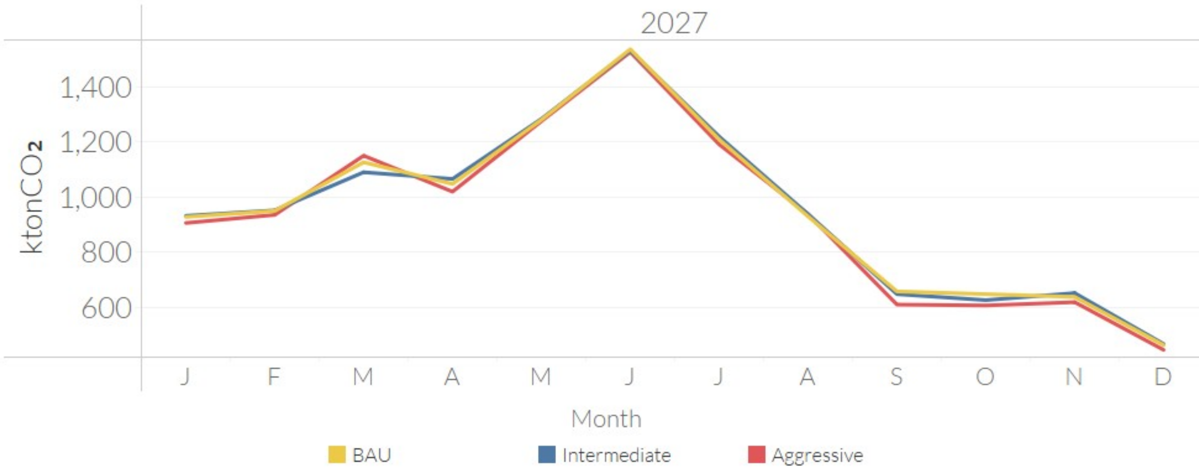
Under **dry** hydrological conditions, emissions are higher than in previous cases; in the **BAU** scenario, **14,783 ktonCO$_2$** are expected to be emitted by 2027. For the same year, in the Intermediate ML scenario this value is reduced by **0.4%** with respect to the BAU scenario, reaching **14,730 ktonCO$_2$** and in the Aggressive ML scenario the reduction is **2.7%**, with **14,391 ktonCO$_2$** emitted.

[11] Frequency control in a power system increases or decreases generation to balance demand and maintain frequency.

When evaluating the seasonality of CO_2 emissions, it can be observed that they increase during the winter, between May and July, when thermal generation is higher (Figure 12).

Figure 12: Annual emissions by technology in medium hydrological conditions.

Source: Own elaboration.



Peak emissions occur in June, with **1,537 ktonCO₂** in the BAU scenario, for the **medium** hydrological conditions. The largest difference between BAU and the Aggressive ML scenario are observed in the spring months (September to November, with a **6%** difference); and emissions reach their lowest in December: **464 ktonCO₂** in the BAU scenario.

In terms of local pollutant emissions, reducing the minimum load of gas-fired units in the Aggressive ML scenario significantly lowers the number of start-ups and shutdowns—by 14% to 31%, depending on hydrological conditions. As a result, nitrogen oxides (NOx) emissions during start-ups and shutdowns also drop substantially — by 49% to 55%. Lowering the minimum load of gas generation also affects NOx emissions during steady-state operation. Depending on hydrological conditions, NOx emissions from normal operation increase slightly by 3% to 4% (in dry and medium years) and decrease by up to 3% (in wet years). Overall, total NOx emissions from gas-fired unit operation are reduced by 10% to 18%.

In the case of coal-fired units, the benefits are less pronounced. Reducing the minimum load leads to a slight decrease in the number of start-ups and shutdowns in the Aggressive ML scenario—between 2% and 8% depending on hydrological conditions compared to the BAU scenario. This reduction does not occur in the Intermediate ML scenario. As a result, start-up and shutdown emissions in the Aggressive ML scenario decrease for NOx, sulfur oxides (SOx), and particulate matter (PM) by 3% to 6% under dry hydrological conditions, and by 12% to 14% under wet conditions, depending on the pollutant.

Emissions during steady-state operation show much smaller variations. In the Intermediate ML scenario, emissions remain virtually unchanged across all pollutants and hydrological conditions. In the Aggressive ML scenario, a slight reduction in local pollutant emissions during steady-state operation is observed, ranging from 0 to 5%, depending on the hydrological conditions and pollutants.

At an aggregate level, local pollutant emissions from coal-fired plants remain nearly constant. In the Aggressive ML scenario, NOx and SOx emissions increase by less than 1% under medium and wet hydrological conditions compared to the BAU scenario, but decrease by 1% and 2%, respectively, under dry conditions. PM emissions decrease between 3% and 5% across all hydrological conditions.

Conclusions

This study demonstrates that lowering the ML of coal- and gas-fired units facilitates renewable energy integration, reduces curtailment, and lowers energy costs. In addition, it allows to reduce thermal generation, which, in turn, reduces CO_2 emissions. The following table summarizes the main results obtained for a medium hydrological condition in 2027.

CHARACTERISTIC	BAU	Intermediate ML	aggressive ML
Thermal generation* (GWh)	*13,002*	*12,902 (-0.8%)*	*12,330 (-5.2%)*
Daytime dispatch out of economic order (GWh)	*601 (65%, coal)*	*545 (64%, coal) (-56 GWh, -1%)*	*348 (51%, coal) (-253 GWh, -14%)*
	377 (94%, gas)	*387 (94%, gas) (10 GWh, 0%)*	*271 (90%, gas) (-106 GWh, -4%)*
Curtailment (GWh)	*9,388*	*9,312 (-76 GWh)*	*8,756 (-632 GWh)*
MgC at nighttime (USD/MWh)	*59.9*	*59.7 (-0.3%)*	*58.3 (-2.7%)*
Sidepayments (USD/MWh)	*3.52*	*3.46 (-1.7%)*	*2.90 (-17.6%)*
Emissions* (ktonCO_2)	*11,420*	*11,411 (-0.1%)*	*11,230 (-1.7%)*

*coal, gas and diesel

In Chile, thermal power plants have significantly reduced their ML and rank among the most flexible globally. An additional reduction is proposed—pushing the boundaries of thermal plant flexibility—though the changes would be marginal compared to the current MLs of some units. As a result, while the system benefits from lower MLs, the overall impact is limited. The reduction in the ML of coal- and gas-fired power plants would lead to a 1–5% decrease in thermal generation by 2027. Lower thermal dispatch leads to less curtailment: from 9.4 TWh in the BAU scenario, to

9.3 TWh in the Intermediate ML scenario and to 8.8 TWh in the Aggressive ML scenario because of a greater reduction in ML.

When coal power plants lack flexibility, they cannot remain online during daytime hours without incurring side payments or causing renewable curtailment. In such cases, units are dispatched at their minimum load out of merit order for system security reasons, but their operating costs are not covered through normal market mechanisms. These units must be compensated to cover their costs, and the resulting sidepayments are covered by all market participants which supply PPA contracts. Depending on contract terms, these compensations may be passed directly to consumers if the contract allows it, or indirectly through energy prices.[12] By reducing out-of-merit dispatch, system costs decrease, which can help lower energy prices for energy consumers.

If coal units are not kept running, some side payments can be avoided, but the system must then rely on faster-starting, often more expensive generation sources. This increases marginal cost volatility. In contrast, operating coal units at lower loads helps stabilize marginal costs and reduce price volatility. A system with lower volatility and fewer side payments enables more efficient tariffs, which ultimately results in lower electricity prices for end consumers over the long term.

In particular, in the Aggressive ML scenario, out-of-merit daytime generation from coal and gas units decreases by 42% and 28%, respectively, compared to the BAU scenario. This leads to a reduction in average system sidepayments of 0.6 USD/MWh and a decrease in nighttime marginal costs of 1.6 USD/MWh, both relative to the BAU scenario in 2027.

At an aggregate level, total system sidepayments in the BAU scenario amounted to 318 MUSD in 2027. In the Intermediate scenario, this figure drops to 312 MUSD, representing a 6 MUSD savings from moderately flexibilizing coal-fired plants. The savings are more significant in the Aggressive ML case, where system sidepayments reach 255 MUSD—an overall reduction of 63 MUSD due to flexibilization of both coal and gas units. When analyzing savings over the 2025–2027 period, total savings amount to 23 MUSD in the Intermediate ML scenario and 169 MUSD in the Aggressive ML scenario. The benefits in terms of reduced sidepayments clearly outweigh the costs: 0.5 to 2 MUSD per unit—totaling 6 to 24 MUSD for the entire Chilean coal fleet. For gas units, flexibilization incurs no additional cost, as it results from a regulatory measure rather than a technical modification.

CO_2 emissions are also reduced due to the decrease in ML. In 2027, the reduction is 0.1% and 1.7% for the Intermediate ML and Aggressive ML scenarios, compared to BAU. This also implies a reduction in associated payments. At a 5 USD/ton CO_2 rate, between 2025 and 2027, the payment associated with CO_2 emissions would be reduced by 0.4 MUSD in the Intermediate ML scenario, and by 5.4 MUSD in the Aggressive ML scenario with respect to BAU.

[12] Compensations can be passed directly to customers if the contract allows it; if not, the supplier generally estimates these costs and implicitly incorporates them into the energy price.

Local pollutants are also reduced, particularly in the case of gas-fired units, which experience fewer starts and stops—operations that are typically NO_X -intensive. As a result, total NOx emissions from gas units in 2027 decrease by 10% in the Aggressive ML scenario compared to BAU. For coal units, the benefits are less clear. In the Intermediate ML scenario, total emissions of NOx, SOx, and particulate matter (PM) from coal plants remain virtually unchanged. However, in the Aggressive ML scenario, PM emissions decline by 4% under medium hydrological conditions in 2027.

The current environmental regulation in Chile, which limits concentration of pollutants in the flue gas of thermal power plants, does not accurately reflect total emissions into the atmosphere and unnecessarily restricts system operation. Allowing gas-fired units to operate at their design minimum load—without the existing constraints set by emissions regulation in Chile—could significantly reduce both global and local emissions, while improving the economic efficiency and competitiveness of the power system. While local pollutant concentrations in the flue gas increase at lower loads, this does not necessarily lead to higher net emissions, because at lower loads exhaust airflow also decreases.

The positive effects observed in this study for the Chilean power system could be even more pronounced in markets with a higher share of thermal generation. In systems where coal and/or gas-fired power plants are more prevalent, or where minimum loads remain high, and no reduction measures have been implemented—such as in Chile since 2019—lowering these values could deliver significant improvements in operational efficiency, cost reduction, and greenhouse gas emissions. Therefore, measures to reduce minimum loads are not only relevant for Chile but could have an even greater impact in other power systems with high reliance on thermal generation, enhancing their sustainability and competitiveness.

Supported by:

Federal Ministry
for Economic Affairs
and Climate Action

on the basis of a decision
by the German Bundestag

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Co-funded by
the European Union