Thailand Power System Flexibility Study

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Abstract

With the growing share of renewable energy and emerging technologies, establishing and maintaining adequate flexibility is an important part of Thailand's power system development and modernisation, and the country's clean energy transition. Power system flexibility is crucial for ensuring security of supply. Thailand's power sector has two main avenues to enhance its flexibility. One is to enhance the technical flexibility of the system. The other is to change or reform commercial and contractual structures. This study examines flexibility from both the technical and contractual angle, and their interactions, using the current context of Thailand's power system. For technical flexibility, the report analyses the flexibility requirements and assesses the value of technical flexibility options, including flexible power plants, pumped storage hydro and battery energy storage systems. For contractual flexibility, the report analyses the impacts of existing power purchase agreement and fuel supply contract structures on system flexibility. This report provides recommendations for the system to be able to use the full range of flexibility options in the most cost-effective and secure way.

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Comments and questions on this report are welcome and can be addressed to EMS-RISE@iea.org.

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Executive summary

Establishing and maintaining sufficient flexibility is important for the development and modernisation of Thailand's power system, and for the achievement of a transition to low-carbon energy. While the Thai power system has significant latent flexibility and a high reserve margin, it will nevertheless need to adapt to the greater need for flexibility that comes with ongoing changes on both the demand and supply side.

Thailand's power sector has two main avenues to enhance its flexibility. One is to enhance the technical flexibility of the system through investment in flexible power plants, the electricity network, and storage and distributed energy resources. The other is to change or reform commercial and contractual structures – including power purchase agreements and fuel supply contracts – to allow current assets to operate more flexibly. Thailand needs both avenues to ensure that it can use flexibility optimally from the perspective of the overall system. But in order to utilise the system's latent technical flexibility, its institutional and contractual structures must allow it. Thus the interaction between technical and contractual flexibility is critical, and is examined in this report.

This study consists of two main components: **1) technical flexibility** and **2) contractual flexibility**. The technical flexibility section analyses the value and impact of a range of options as a growing share of renewables comes online. The contractual flexibility section analyses the impacts of existing power purchase and fuel supply contract structures on system flexibility. This study was conducted in the context of the current "enhanced single-buyer model", which is used in Thailand. While market reform can be a highly effective option to increase flexibility, it is outside of scope of this study.

Technical flexibility

Advanced production cost modelling, which simulates the cost-effective and reliable operation of the Thai power system on a 30-minute basis, was conducted to understand its flexibility requirements and to assess the value of flexibility resources from the technical and economic perspective. The analysis considers a set of technology deployment scenarios for 2025 and 2030. For each of the modelled years, the model uses a primary set of scenarios to assess the value and impact of individual technical flexibility options, including: flexible power plants; pumped storage hydro (PSH); battery energy storage systems (BESS);

and a combination of these options. These scenarios build on the current plan, which aligns with Thailand's latest Power Development Plan (PDP 2018 Revision 1). The scenarios consider the share of VRE according to the PDP (4% in 2025 and 6% in 2030), and the progressive VRE scenarios (6% in 2025 and 15% in 2030) to explore the value of the options under different annual VRE uptakes. The study also considers the implications of flexible fuel supply contracts for technical flexibility options.

New technical flexibility options are not a priority for Thailand's power system in the short to medium term

Under the existing arrangement of Thailand's power system, the modelling results suggest that the system has latent technical flexibility to integrate up to 15% VRE by 2030, but barriers surrounding power and fuel procurement often prevent that flexibility from being accessed. The benefits of investing in technical flexibility options – including retrofitting the generation fleet to improve plant flexibility and deploying new storage options, either PSH or BESS – are not significant, and these option are therefore not a priority in the short to medium term.

Given the constraints in fuel and power purchase contracts currently in place, plant retrofits provide limited benefits to the system from both an economic and operational perspective at this level of VRE penetration. With the share of VRE at 4% in 2025 and 6% in 2030, as per the PDP, the operational cost savings from plant retrofits are less than 0.05%. Although the cost savings increase with higher deployment of VRE, the savings from plant retrofits remain modest in the scenarios with accelerated VRE uptake. Meanwhile, the investment cost of targeted plant retrofits would far outweigh the operational cost savings. Instead of plant retrofits, modifications to certain plant operational procedures (especially for independent power producers) or market and regulatory incentives should be considered as an option to potentially unlock latent power plant flexibility.

The deployment of PSH and BESS can lead to the more efficient use of cheaper generation sources during off-peak periods, while displacing more expensive peaking capacity. Despite their technical capability in providing system services, the operational cost savings with new PSH and BESS (both in isolation and paired with flexible power plants) are still modest (less than 0.1%), even with an accelerated VRE target of 15% in 2030. The small cost savings are due to the current fuel supply and power purchase contracts. At this stage, the cost of investing in PSH and BESS would still outweigh the operational cost savings.

As more VRE is deployed, power plant flexibility and storage may become highly complementary options

As Thailand further accelerates its clean energy transition, the country should still consider using a combination of flexibility options in its long-term planning to accommodate greater ambition for renewable energy deployment. Beyond 2030 as the system move towards higher shares of VRE, investing in plant retrofits and new storage options may become a viable option once the operational practices are addressed and there have been institutional changes to fuel and power procurement contracts.

From the technical standpoint, the most constrained dimension of power plants in the model is the minimum stable level (MSL). Hence reducing the MSL should be one of the priorities for EGAT when investing in a new power plant or negotiating a new power purchase contract. As the share of VRE continues to grow, storage options will play a larger role in providing flexibility services. From a purely technical perspective, given various levels of VRE penetration in 2030, BESS see greater utilisation compared to PSH due to their higher efficiency, fast response time and capability for more flexible operation, which suits Thailand’s demand and supply patterns. On this basis, it is important to ensure Thailand has the appropriate policy and regulatory frameworks to enable BESS to provide the full range of services they are technically capable of.

The value of technical flexibility resources are highly dependent on the structure of fuel supply contracts

The existing fuel supply contract arrangement in Thailand, which is subject to minimum take-or-pay quantities, prevents the use of otherwise available and cost-optimal resources in the system. This leads to unnecessary increases in system operational costs. Under the modelling scenarios that feature flexible fuel supply contracts in 2025 and 2030, the results demonstrate a significant reduction in operational costs (up to approximately 2%) as system operators can access a large amount of latent flexibility in the system and dispatch the system in a more cost-effective manner. Designing fuel supply and power purchase contracts with sufficient flexibility leaves headroom for lower-cost energy sources such as VRE to participate in the market. While relaxing fuel supply constraints is not simple to implement in practice, the potential for cost savings means that it merits further exploration.

Contractual flexibility

In order to be able to enhance flexibility, it is important to ensure that prevailing contractual structures allow the system's technical capabilities to be used. In Thailand many independent power producers are contracted through physical power purchase agreements that have minimum-take obligations, defined as the minimum generation EGAT is contractually obligated to buy. Minimum-take obligations in Thailand are different during the peak versus the off-peak: a 100% minimum-take obligation is typical during the peak consumption hours, while the corresponding obligation during the off-peak is 65% of capacity.

Thailand has an enhanced single-buyer system, which means that the vertically integrated utility buys power from both its own generation assets and from independent power producers. This study is conducted in the context of the enhanced single-buyer system, and identifies contractual flexibility within this scope. Thailand is also set to increase its share of renewables in electricity generation, which creates a need for more flexible generation from the thermal fleet to accommodate variable renewables.

Minimum-take obligations create structural inflexibility

This study analyses the actual minimum-take obligations both from independent power producers and imports from the Lao People's Democratic Republic against projected renewable generation and consumption. It constructs scenarios to reflect high levels of renewable generation combined with low levels of consumption, and vice versa, in order to study whether the contractual structures – and specifically the minimum-take obligation – creates structural inflexibility for the Thai system.

The analysis shows that the minimum-take obligations, particularly in the off-peak, lead to the over-commitment of generation, which pushes up operational costs and leads to uneconomic VRE curtailment**. During the off-peak, consumption is too low to absorb both high levels of renewables and the contractual minimum-take generation**. This can potentially be solved by increasing flexibility in imports, which also shows the importance of developing more flexible models for multilateral trade with neighbouring countries. Thailand should study the level of import flexibility that is technically possible from a security perspective, and whether potential grid enhancements can increase this flexibility if needed. Future power purchase agreements should seek to reduce general minimum-take obligations and move to more flexible contracts so as to provide the contractual flexibility needed to integrate higher shares of renewables. The level that minimum-take obligations should be reduced to would depend on the contractual flexibility of the wider power portfolio, as well as the technical capabilities of the generation fleet.

Fuel supply contracts can create inflexibility, which can be mitigated by portfolio procurement

In addition to the minimum-take obligations of power purchase agreements, EGAT also has take-or-pay obligations in its fuel supply contracts for gas. These have elements of daily take-or-pay obligations, which significantly limit flexibility and increase system operational costs.

EGAT's gas contracts are reviewed every five years. It is recommended that, at review, the take-or-pay obligations are relaxed to allow for greater flexibility to integrate renewable energy in the dispatch of generation.

LNG provides a good option to increase flexibility in gas supply contracts, since LNG contracts tend to be more flexible. It is important to note that adding further LNG to Thailand's supply contracts would require a corresponding reduction in the take-or-pay amounts in current gas contracts. In general, it is important for EGAT to implement a portfolio approach to gas procurement, which mixes less-flexible long-term contracts with more-flexible shorter-term contracts. In this way it can optimise fuel supply contracts with respect to cost and flexibility in order to provide the necessary fuel supply flexibility in the future. Increasing gas contract flexibility will come at a cost, and the specific contract terms should be studied against the cost of take-or-pay obligations.

Thailand's power sector and power system flexibility

According to Thailand's most recent Power Development Plan (PDP 2018 Revision 1), the government aims to increase the proportion of generating capacity powered by renewable energy sources to 36% by 2037. The country is experiencing accelerated uptake of variable renewable energy (VRE), particularly solar PV, due to technology improvements and rapid cost reductions.

In accommodating the growing share of VRE and new technologies, Thailand's power system has to adapt to the need for greater flexibility resulting from changes on both the demand and supply sides, as well as the commercial implications of fuel supply and power purchase contracts. Flexibility is crucial for the operation and future planning of any power system. Establishing and maintaining adequate flexibility is therefore an important part of Thailand's power system development and modernisation, and the country's clean energy transition.

Against this background, our study explores a series of issues:

- The appropriate technical flexibility options in the short and medium term based on techno-economic analysis under an increasing share of VRE, particularly distributed solar PV.[1]
- Flexibility options including power plants, pumped-storage hydro (PSH) and battery energy storage systems (BESS).[2]
- The impacts of existing power purchase and fuel supply contract structures on current system flexibility.
- The appropriate options for existing and future contract structures, both for fuel supply and offtake of electricity, as well as domestic and international contracts.

Thailand's power sector

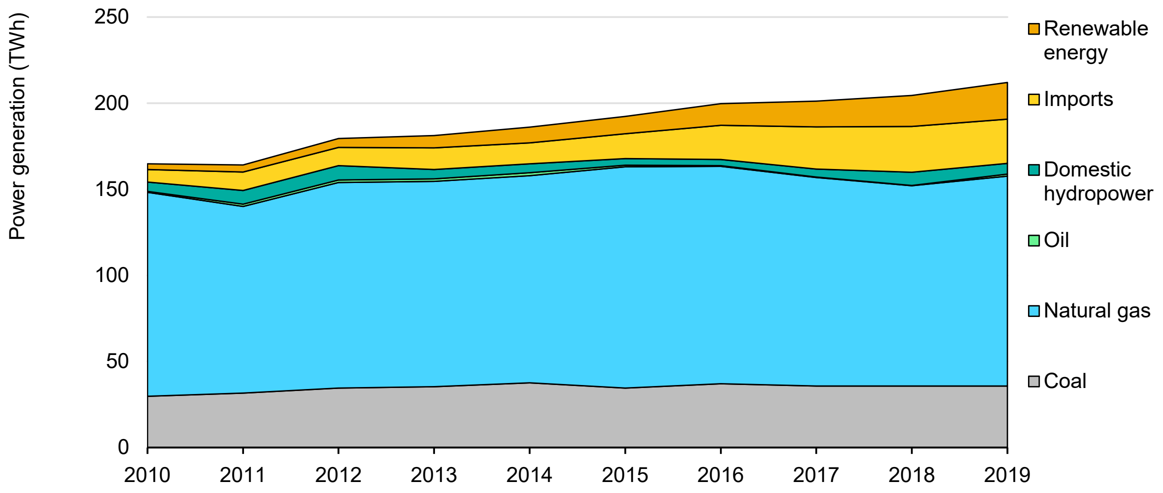
Thailand's electricity industry is structured under an "enhanced single-buyer model". Under this model, the government-owned Electricity Generating Authority of Thailand (EGAT) is responsible for transmission system operation and

[1] Advanced power system modelling exercises were performed using the PLEXOS® production cost modelling framework.
[2] Other flexibility options, including demand response and electric vehicles, are not considered in this study. Some of these options were considered in a previous study.

electricity generation. EGAT also acts as the single buyer, purchasing bulk electricity from private power producers, which consist of independent power producers (IPPs), small power producers (SPPs) and neighbouring countries. EGAT sells wholesale electricity to Thailand's two distribution utilities, the Metropolitan Electricity Authority and the Provincial Electricity Authority, as well as a small number of direct industrial customers and utilities in neighbouring countries. Generators connected to the systems of the two electricity authorities are called very small power producers (VSPPs).

Natural gas has been the main fuel source for electricity generation in Thailand over the past 20 years, accounting for around 70% of total generation in the early 2000s. In the past few years the generation mix has become more diversified, with the share of gas-fired generation falling to close to 60% in 2019, and the share of renewables and imports increasing. The share met by coal remains relatively stable at around 20%. The share of electricity from renewable energy has steadily increased, particularly during the past couple of years, rising from 12% of total generation in 2017 to almost 20% in 2019. Renewable energy is predominantly from hydropower (both domestic and imports), while solar and wind generation accounted for around 4% of total generation.

Figure 1.1 Thailand's power generation by fuel type, 2010-2019

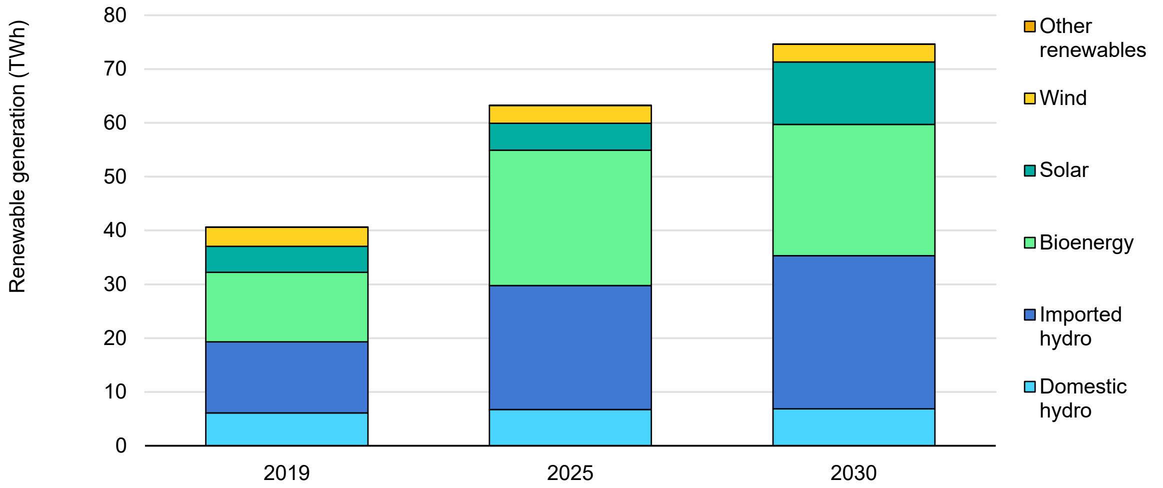


Notes: Imports consist of foreign hydropower and lignite. Renewable energy consists of wind, solar PV and bioenergy.
Sources: Energy Policy and Planning Office (2020), Electricity; EGAT.

Thailand's total installed generation capacity was 47 GW in 2019, with 30 GW being gas-fired power plants, 6 GW coal-fired and 11 GW from renewables (including hydropower capacity built in neighbouring countries to serve Thailand). Peak electricity demand in 2019 was around 30 GW.

Imported hydropower and domestic biomass accounted for more than half of the country's total renewable generation (domestic and imported) in 2019. Wind and solar PV together accounted for around 20% of total renewable generation (Figure 1.2). According to the PDP, imported hydropower and domestic solar PV are expected to increase substantially over the next ten years. By 2030 the share of renewables in total electricity generation is expected to increase to around 25%.

Figure 1.2 Renewable generation in Thailand, 2019, 2025 and 2030



Source: EGAT.

Reflecting the global trend for energy transitions and renewable energy, Thailand has a broad set of policies to cost-effectively accelerate the uptake of cleaner energy. The latest PDP provides a roadmap for the power sector's transition with three key principles: energy security, economic sustainability and environmental sustainability. The renewable energy target for electricity (excluding imported hydropower) is set at 29% of total generation by 2037, with an additional 6% energy efficiency target. Renewables capacity is expected to reach 29 GW in 2037, accounting for around 35% of total capacity.

With lower than expected demand growth in recent years, Thailand's power sector is facing the issue of generation overcapacity and a high reserve margin, which has been in the range of 40%. This situation is expected to become more acute due to the impact of Covid-19, which has decreased electricity demand. A number of options are being considered, including retirements of ageing power plants with relatively low efficiency and delaying investment in large-scale fossil fuel power plants.

The importance of power system flexibility

Power system flexibility is crucial for ensuring security of supply in modern power systems and for a successful clean energy transition; it is the ability of the system to handle the variability and uncertainty of the system. Driven in many regions by a higher share of VRE in electricity generation, power system flexibility is becoming increasingly important for policy makers and system planners to consider. Power system flexibility refers broadly to all the attributes of a power system that allow the system operator to reliably and cost-effectively balance demand and generation in response to variability and uncertainty. Flexibility is an important factor at all timescales, ranging from several years to seasons, days, hours, minutes and seconds.

Grid modernisation is a prominent part of the 2018 PDP for improving the reliability, resilience and flexibility of the power system in response to the rapid uptake of emerging technologies in Thailand, particularly VRE.

There are two main avenues to enhance flexibility in power systems. One is to change or reform commercial and contractual structures, such as power purchase agreements (PPAs), to allow current assets to operate more flexibly. The other is to enhance the technical flexibility of the system itself and operational practices across the value chain from generation to distribution and to consumers. Often both approaches are needed to ensure that flexibility is optimally utilised from the perspective of the overall system. From a contractual perspective, future arrangements governing power plant fuel procurement and power purchase need to be reviewed to ensure the appropriate level of flexibility. From a technical perspective, Thailand's future electricity system must facilitate the deployment of flexibility, including options at power plants, on the electricity grid, on the demand side and for storage. These sources of flexibility are highly dependent on each other. Both contractual and technical options must be considered simultaneously in the effort to enhance flexibility, since technical flexibility without the appropriate contractual structures can be more challenging to implement, and vice versa.

Electricity systems are designed to cope with variability and uncertainty on the supply and demand side. Historically, variability came mainly from the demand side, while uncertainty was rather a supply side issue, often caused by the risk of the sudden loss of a large generator or transmission asset. Requirements for flexibility are evolving, particularly as the share of wind and solar PV increases. VRE output is constrained by the instantaneous availability of wind and solar irradiation. This makes them both *variable* and partly *uncertain*: variable because the output varies over time depending on the availability of primary resources (wind or sun); and uncertain as the output cannot be perfectly forecasted, especially not at longer lead times. Advanced forecasting techniques are available to accurately predict the amount of wind or solar energy available and reduce the uncertainty of the available generation capacity. The use of forecasts requires operational changes. Grid operators need to be aware and convinced of the benefits of integrating forecast data in daily operations.

Variability and uncertainty trends are visible in many systems where the flexibility needed to meet faster ramping and a wider spread in load in a day has evolved substantially over the past decade. According to the Thailand Renewable Grid Integration Assessment in 2018, Thailand's power system is still considered flexible from a technical perspective given the reasonable share of electricity from hydropower, the high share from combined-cycle gas turbines (CCGTs) and the high reserve margin. The transmission system has a number of advanced transmission equipment and protection schemes. The entire system possesses dynamic stability and robust grid strength, as well as adequate primary and secondary response mechanisms. However, institutional and contractual constraints limit the mobilisation of this flexibility. We examine the interaction between technical and contractual flexibility more closely in this report.

Potential flexibility options for Thailand's power system based on international experiences

There are four principal sources of technical system flexibility: power plants (both conventional and VRE); electricity grids; energy storage; and distributed energy resources (including demand response and electric vehicles). Conventional power plants, the electricity grid and PSH have historically been the primary sources of technical flexibility. However, contractual updates and operational protocol improvements in VRE power plants and electricity grids, and cheaper BESS, are enabling a wider set of flexibility options for consideration.

Grid flexibility is one of the prominent approaches in the 2018 PDP Revision 1 to maintaining the effectiveness and resilience of the power system in response to novel technology trends. Thailand is one of the most advanced countries in the Association of Southeast Asian Nations (ASEAN) in terms of VRE penetration, and has a number of flexibility options that currently exist or it can draw upon. The renewable energy target for electricity has increased from 20% of installed capacity by 2036 (specified in the previous PDP in 2015) to 36% by 2037 in the

2018 PDP Revision 1, with solar PV being the largest resource, accounting for 22% (compared to a 6% target previously).

Power plants

Conventional power plants are operated subject to their technical capability, which typically includes the minimum stable level (MSL) at which a specific generator can operate, the rate at which power output can be adjusted (the ramp rate), start-up and shutdown times, and constraints on how often a generator can be cycled (minimum up/down times as well as number of start-ups). Power plants will be required to vary their generation outputs more significantly due the growing share of VRE and the associated variability and uncertainty of net demand as a result. As a useful example, hourly variations in thermal generation in India have significantly increased from 2-4 GW in 2008 to 6-8 GW in 2017 as the share of VRE approached 10%. They are projected to be as high as around 30 GW per hour with the integration of 100 GW solar and 60 GW wind by 2022.

A range of strategies can make existing conventional power plants more flexible. These can be categorised into two areas: changes to operational practices, including contractual structures; and investment in flexibility retrofits. From international experience, the operating characteristics of conventional power plants can be significantly improved after retrofitting (Table 1.1). These characteristics are in line with the first power plant flexibility pilot projects in Thailand (discussed in the next chapter).[3] Retrofits can result in increased operation and maintenance costs and reduced efficiency over the remaining lifetime of the unit.

Table 1.1 Average operating characteristics of conventional technologies

Technology	Minimum operating levels (% of capacity)		Ramp rate (MW/minute)		Warm start time (hours)	
	Typical	Retrofit	Typical	Retrofit	Typical	Retrofit
CCGT	45%	30%	21	56	1.6	0.5
Coal	37%	20%	21	60	6	2.6
OCGT	35%	20%	29	60	0.7	0.3

Note: OCGT = open-cycle gas turbine.

Sources: IEA (2017), *Energy Technology Perspectives 2017*; NREL (2012), *Power Plant Cycling Costs 2012*; Gonzalez-Salazar et al. (2018), "Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables"; Siemens (2017), *Flexibility of Coal and Gas Fired Power Plants*; Agora Energiewende (2017), *Flexibility in Thermal Power Plants.*

[3] Changing the operating characteristics can affect the efficiency of power plants.

Taking the People's Republic of China ("China") as a further example, about 220 GW of the country's thermal power plants, including co-generation and condensing power-only units, could be retrofitted to improve their flexibility by replacing old equipment or updating operations by 2020. This would account for around 20% of China's overall thermal capacity. India is implementing pilot projects to improve the flexibility of thermal plants to identify the flexibility capability of its thermal plants. Retrofitting thermal power plants initially designed to operate as baseload can be a very cost-effective way of enhancing their flexibility, given the appropriate financial incentives.

Based on experiences in China, Denmark, Germany and the United States, retrofit costs to enhance power plant flexibility vary significantly (Table 1.2) (Agora Energiewende, 2017; CEM, 2018; COWI, 2017; NREL, 2013). They depend on a number of technical factors,[4] and may vary significantly since they are context- and country-specific, depending on a number of factors such as age, technology type, plant configuration and technical attributes.

Table 1.2 Retrofit costs to improve power plant flexibility

Improvement	Coal-fired subcritical (USD/MW)	Coal-fired supercritical (USD/MW)	CCGT (USD/MW)
Lower MSL	5 600–10 000	3 700–5 300	1 100–2 600
Faster ramp rate	600–1 100	300–820	1 300–2 000
Faster start-up time	1 000–7 500	1 00–5 300	4 400–6 600

Significant investment, however, may not be necessary to operate power plants more flexibly. Flexibility improvements may also be achieved by updating the software and monitoring and control mechanisms. In some cases, however, physical upgrades or overhaul of the plant components may be required. Power plants with advanced infrastructure may only need upgraded software and control systems, while those with ageing hardware may need greater investment in technical retrofitting.

Hybrid power plants, which combine two or more technologies, are increasingly becoming a viable means of boosting flexibility, both in technical and economic terms. This is an emerging trend in many countries. These technologies can include a combination of both VRE and conventional power plants combined with BESS. One example of an innovative flexibility retrofit at an existing power plant is the Center Peaker Plant in California, which is a natural gas peaking power plant

[4] E.g. improving durability of plant components to withstand thermal stresses and rapid changes in combustion process; installing a new boiler; and adjusting the firing system to maintain flame stability.

coupled with BESS that can offer spinning reserves without burning any fuel, while also offering frequency response. The first hydro-floating solar hybrid pilot project in the northeast of Thailand, once it is in full operation in 2021, also has the potential to contribute to system flexibility from a technical perspective. The target capacity of the hydro-floating solar plant is more than 2 GW, and it is being installed on existing hydro reservoirs thus minimising the investment costs in network infrastructure and land use.

Grid-connected solar PV and wind power plants have the capability to provide flexibility services, as demonstrated in Australia where during an instability event solar PV plants have provided short-term frequency response. However, this requires adequate technical specification of the services that must be provided, as well as appropriate contractual structures.

The potential benefits and operational impact of power plant flexibility in Thailand is analysed in detailed in the next chapter.

Electricity network

Interconnections between different regions enable the system to become more flexible by connecting different sources of flexibility, allowing them to be shared across a wider area. They also lower aggregate flexibility requirements because the variability and uncertainty of supply and demand decline when larger geographical areas are connected. Similarly, VRE resources also typically have a smoother aggregate profile that is easier to integrate when spread across a larger region. However, sources of flexibility can be underutilised due to interconnection congestion. When congestion occurs, it is important that contractual and institutional structures are in place to ensure the system is fully utilised in the most effective manner. In many systems such as in the European Union, transmission grid infrastructure, which includes interconnectors, accounts for the largest share of investment in the power system.

Although Thailand's existing transmission grid is one of its most important flexibility resources, the growth of VRE can present operational challenges to the system. The 2018 PDP Revision 1 specifies regional power development plans that allocate the share of generation technologies in each region. This concept is deemed effective from a regional self-sufficiency perspective; however, it is also necessary to consider the expansion of inter-regional interconnectors as the deployment of VRE can often outpace network development. The amount of generation in each region is projected to change significantly, leading to changes in power flows (both in magnitude and direction). For example, the North-eastern region's generation capacity in 2037 is projected to almost triple from 2018 levels (from 6 GW to 16 GW), while regional peak demand is forecast to double (from 4 GW to 8 GW), which suggests a greater level of power exports to other regions within Thailand. At the same time, peak demand growth in the Central region is expected to double (from 11 GW to 23 GW), while its generation capacity is projected to increase by only 10% (from 28 GW to 31 GW), indicating a growing dependence on power imports from other regions. Interconnection allows for demand in the Central and Metropolitan regions to be met by generators from Northern and North-eastern regions during periods when local generation resources are already at maximum output.

Network development will need to anticipate where VRE plants are likely to be built. Geographic concentrations of VRE in areas with the highest-quality resource can place a burden on the transmission grid and lead to congestion, which is likely to occur in the Central and Metropolitan regions. This issue is relevant for both transmission and distribution networks, where additional VRE may change traditional energy flows and the use of the grid, while connections on local grids may challenge distribution system operations.

Storage

Storage provides flexibility to the system by allowing it to store energy from wind and solar PV during times of low demand and then release it at times of system peak. While this can simply reflect the economic use of excess wind and solar PV generation, it can also compensate for less flexible conventional generation that may not be able to ramp up generation sufficiently quickly as wind or solar generation declines. This is especially true of solar PV generation, which will generally peak around midday, but then decline as the afternoon progresses, often corresponding with a jump in demand at the evening peak.

PSH accounts for the bulk of electricity storage projects worldwide, representing 94% of global utility-scale storage projects (equivalent to 160 GW of capacity in 2019). Due to the declining costs of **BESS**, driven by economies of scale in the production of electric vehicles, batteries are becoming increasingly cost-competitive. They have a number of advantages over other technologies as they can be modular in size and built for a specific purpose. For example, a battery system can be built with a high power rating (MW) and small energy storage capacity (MWh) if needed to provide short-term ancillary services, or alternatively built with longer duration storage (typically around 4 hours) in order to be able provide energy for entire peak demand periods. By comparison, PSH is limited to very specific geographies and its main benefit is its longer duration of storage, allowing it to be used across multiple days if needed. Specific use cases therefore favour specific technologies and configurations, which may be driven by, among other things, ownership structures, financing and revenue streams.

We assess the benefits of PSH and BESS for the system in the next chapter on technical flexibility.

PSH

In Thailand PSH is expected to remain an important flexibility resource with the increasing share of VRE and distributed energy resources. The system has a single 1 GW (4 x 250 MW) PSH plant at Lam Takhong in the northeast of the country, accounting for 25% of the total domestic hydropower capacity. At present Thailand has the largest PSH capacity within ASEAN (1 GW); however, the Lao People's Democratic Republic (PDR) and Viet Nam have plans to install large PSH plants with installed capacity of around 1 GW and 3 GW respectively by 2030.

According to the 2018 PDP Revision 1, the amount of domestic PSH capacity appears to remain static despite the growth of imported hydropower capacity. Nonetheless, there is uncertainty in the foreign hydropower purchase arrangements, and the type of hydro resources and technologies that may be available in neighbouring countries. Given such uncertainty, Thailand should explore the opportunity of setting a minimum PSH capacity target for imported hydropower purchases in order to improve system flexibility. The opportunity to develop PSH projects domestically should also be considered given its flexibility to accommodate increasing shares of VRE. Although Thailand's domestic PSH accounts for a relatively high share of total domestic hydropower capacity, none of the imported hydropower capacity from Lao PDR consists of PSH. As a result, the total share of PSH capacity when including both domestic and imported hydro generation is only around 10% of all hydropower capacity.

The benefits of PSH in providing flexibility are evident in Japan's southernmost island, Kyushu, which has the highest VRE penetration in Japan. The general dispatch practices involving PSH are set to prioritise absorption of surplus electricity in pumping mode during the daytime when solar PV is providing high output, and then switch to the generation mode to cover the evening peak demand to accommodate the reducing solar PV output.

The cost of PSH facilities varies widely depending on geological conditions, which are very context specific. For example, the cost range for half of new PSH projects is around USD 650–2 000 per kW. The cost also depends on the type of PSH technology, such as fixed speed, variable speed or ternary. The majority of plants around the world, including in Thailand, are fixed speed meaning that they can only operate at their maximum capacity pumping mode. Variable-speed plants can provide a greater degree of flexibility than fixed-speed plants. The potential benefits of variable-speed PSH to Thailand are analysed in the next chapter.

BESS

Recent progress in BESS is now enabling the provision of cost-effective flexibility at very short to short timescales (seconds to minutes to hours), with extremely fast response times and accurate response to control signals. BESS open new possibilities for the provision of ancillary services, grid protection and fast response during power outages. The potential roles for BESS that are most promising for Thailand include handling high ramping periods and providing rapid frequency response. In recent years a number of large grid-scale battery projects have been developed in countries and regions that require flexibility services, such as Australia, Chile, Puerto Rico, California and West Virginia. One notable example is the Hornsdale Power Reserve in Australia, which is one of the world's largest lithium-ion batteries and is capable of providing frequency response during both normal and contingency events. Despite the rapid cost reduction in recent years, batteries are not yet a fully cost-competitive flexibility resource.

Thailand has two pilot projects for BESS, which have just entered the installation stage in the Central-North region (21 MW/21 MWh) and North-eastern region (16 MW/16 MWh). These batteries only have a storage duration of one hour and hence are primarily intended for system support services. A battery that can provide peak shifting, whereby it charges during off-peak periods and provides peaking capacity during the day, requires a storage duration that is long enough to sustain its maximum capacity for the peak period, which occurs for a few hours in the evening. While this may vary seasonally and geographically (based on the composition of demand driven by consumer profile, electrification, temperature, etc.), storage of up to 4 hours is typically required.

Distributed energy resources

Distributed energy resources, including demand response and electric vehicles, are a key flexibility option. Demand response is one of the main pillars of the smart grid development project in the PDP. The main objectives of the demand response programme in Thailand are to help meet growing demand and address concerns over the security of electricity supply both in the short and long term. A number of demand response measures have been implemented in Thailand, but they are still only pilots. An appropriate future direction to encourage demand response in

Thailand would be to begin with large industrial customers and then allow the participation of commercial and residential customers. Viable strategies include:

- Encourage utilities to consider demand response as a flexibility resource.
- Establish appropriate pricing or financial incentives for demand response programmes that reflect real-time short-run marginal costs.
- Revise the interruptible load programme to make it more attractive to participants.
- Utilise excess capacity from SPPs and VSPPs and integrate them as part of demand response. This can be managed by a dedicated load aggregator who sells this capacity to the responsible utilities.

Electric vehicles are a further resource that can help to reduce Thailand's dependence on imported fossil fuels while also lowering environmental impacts. According to IEA analysis in 2018, electric vehicles with managed charging can enhance system flexibility and accommodate higher VRE penetration while reducing the operational costs of the system.

Technical flexibility

Highlights

Thailand's power system is expected to experience higher ramping requirements and a larger gap between daily peak and minimum net demand. The 3-hour ramping requirement is projected to increase from 6.5 GW in 2019 to 13 GW in the case of a 15% share of VRE in 2030, which accounts for 50% of the daily peak demand. The power system has latent technical flexibility, which lies in many conventional power plants (hydropower and CCGT), to integrate up to a 15% share of VRE by 2030 without any major technical issues. One of the options to increase system flexibility is through targeted plant retrofits, but the operational cost savings from plant retrofits are modest (less than 0.05%). The cost savings increase with higher deployment of VRE, but the retrofit cost still outweighs the operational cost savings at a 15% share of VRE in 2030. From the technical standpoint, the MSL of power plant operation is the most constrained dimension on the system as compared with other operational parameters.

With higher uptake of VRE, the deployment of pumped hydro and storage options (PSH and BESS) provide greater flexibility services, which can further reduce the operational cost of the system. The majority of the system cost savings come from a reduction in start-up costs and fuel costs at conventional power plants. However, the cost savings from additional storage options are still modest (less than 0.1%). From a purely technical perspective, compared to other storage options BESS play a more prominent role in providing system flexibility due their high efficiency and more flexible operation. With flexible fuel supply contracts, the results demonstrate a significant reduction in operational costs in 2025 and 2030 (up to approximately 2%), which are significantly greater than the savings from flexible power plants and storage options combined.

Analytical approach and methodology

Power sector modelling approach and assumptions

We performed production cost modelling of the Thai power system using the PLEXOS© Integrated Energy Model.[1] This is an industry standard, optimisation-based power system modelling tool that allows for detailed production cost modelling. We used a temporal resolution of 30 minutes for forecasted demand profiles, the techno-economic characteristics of power plants (including imports), hydropower energy constraints, transmission lines and VRE generation profiles.[2]

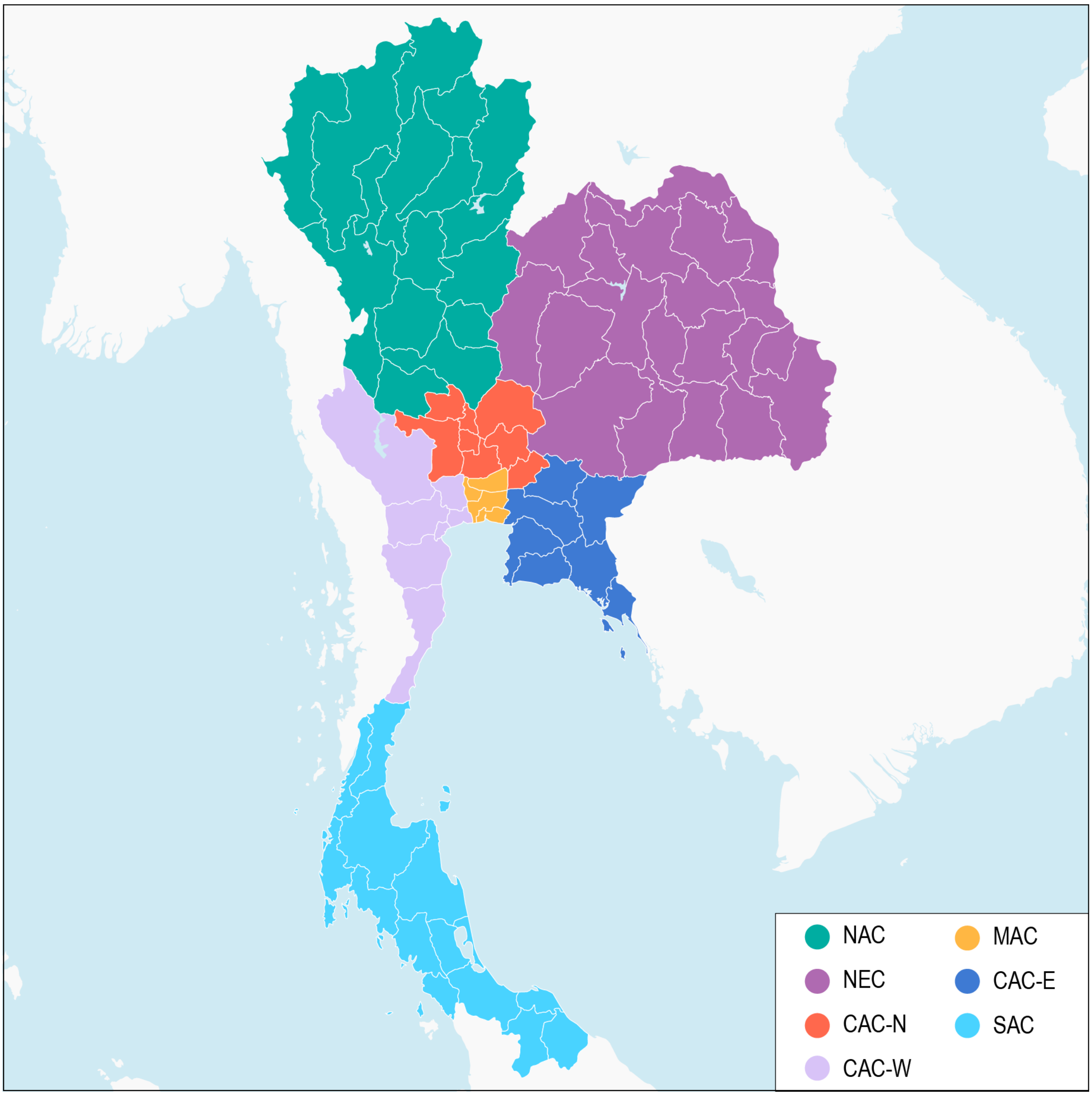
Thailand's power system is represented in the model according to the main "area control" regions designated by EGAT. These comprise five main control regions, and a further disaggregation of the Central region based on EGAT operational procedures due to its large size. This results in the following seven regions (Figure 2.1):

- Central-East (CAC-E)
- Central-North (CAC-N)
- Central-West (CAC-W)
- Metropolitan Bangkok (MAC)
- Northern (NAC)
- North-eastern (NEC)
- Southern (SAC).

While the transmission network is represented in the model, only active power flows are considered; detailed grid stability analysis remains outside the scope of this project. While interconnectors are not explicitly modelled, foreign imports (coal and hydro) from Lao PDR are modelled as generators in the North-eastern region according to the terms of the relevant PPAs.

[1] PLEXOS© is an energy market simulation package for modelling the power system over different time frames, ranging from long-term generation capacity expansion to short-term dispatch and unit commitment.
[2] Note that the results did not consider the technical detail relating to load flow, contingency analysis, short circuit and stability.

Figure 2.1 Representation of the seven control regions in Thailand's power system



Source: EGAT.

The demand forecasts used in the model, including annual peak demand and annual energy, are based on the 2018 PDP Revision 1, while regional load shapes are based on historical profiles from 2017, providing a consistent methodology for the demand forecast as applied in the PDP.[3] We then derived future load profiles for modelling purposes for 2025 and 2030.

[3] While it is understood that changes are anticipated in the demand composition from growth in residential space cooling and electric mobility, these are not explicitly considered in the 2018 PDP and therefore have not been considered in the analysis.

Table 2.1 Thailand's power system modelling set up

Generator	Transmission network	Demand
• Key operating parameters are ramp rates, MSL, contracted generation capacity, simple heat rates, minimum up/down times • Historical operating patterns for non/semi-dispatchable (SPPs, VSPPs) • Gas constraints based on the daily contracted quantity • Hydro energy constraints based on monthly requirement according to actual 2019 data • Wind and solar time series for representative locations in the future scenarios. Locations of distributed PV are based on largest population centres.	• 7 node (region) representation of the system: CAC-E; CAC-N; CAC-W; MAC; NAC; NEC; SAC • Transmission flow limits for 115 kV, 230 kV and 500 kV regional interconnections	• 30-minute demand profiles are projected for 2025 and 2030 based on 2017 profiles • Future demand profiles are subject to the projected regional peak demand and annual energy in 2018 PDP Revision 1

Note: CAC-E = Central-East; CAC-N = Central-North; CAC-W = Central-West; MAC = Metropolitan; NEC = North-eastern; SAC = Southern.

Power plant operational costs consist of fuel cost, start-up cost, variable operating and maintenance cost and ramping cost. All costs are based on those reflected in EGAT PPAs, except for ramping cost, which reflects wear and tear costs due to increased cycling based on international data. In order to manage the simulation times of the model, we assumed start-up costs based on a "warm" cooling state[4] of units only, while assuming a simple heat rate based on generating units at full load. Other power plant characteristics that we modelled include plant outage rates (both forced outages and maintenance) and repair times, and technical constraints of the generating units including ramp rates, run-up rates, minimum up/down times and MSLs. While EGAT provided data on ramp rates, run-up rates and MSLs for existing units, we used international data for the other characteristics.

We categorised gas supply sources for power plants according to each plant's gas obligation, comprising East Gas (domestic sources), West Gas (imported gas from Myanmar) and other gas resources. We assumed future power plants would use LNG. We also considered a daily contracted quantity of gas obligation, exploring its impact on operations. Gas prices from the different sources are in the range of THB 180–220/MBtu.

We modelled semi-dispatchable power plants (known as SPP-Firm) according to historical patterns categorised by EGAT. The SPP-Firm group therefore has a

[4] Generating unit start-up costs and start-up times will depend on how long the unit has been shut down, with units described as either hot, warm or cold. These times will vary according to generation technology.

fixed generation profile in order to meet an annual capacity factor target. To calculate more precise energy production, we also modelled forced outages and maintenance. For non-firm power plants (excluding new wind and solar), we simply assumed historical profiles from EGAT for generation patterns.

We modelled wind and solar PV generation profiles for future years according to the Thailand Renewable Grid Integration Assessment study, which consisted of simulated 30-minute generation over a ten-year period during 2007-2016 in GIS-compatible, 2-arc-minute grids (i.e. roughly 3 km geographical resolution). For wind potential, we simulated the wind speed for two different hub heights: 100 and 150 metres.

Domestic reservoir hydropower plants are dispatched subject to a maximum monthly capacity factor, which varies from month to month, based on historical generation profiles. The plants are free to utilise the available energy as is optimal, subject to the technical constraints of the generator. Hydropower imports are split into either run-of-river or large reservoir plants. We assumed run-of-river plants to have daily pondage, allowing for optimisation of its use on a daily basis. Meanwhile, we treated large reservoir hydropower imports the same as domestic hydropower, except that monthly energy targets (based on its maximum capacity factor) are implemented in a must-take operational manner. PSH plants operate according to existing operational practice, whereby operators ensure reservoirs are full at the end of the weekend, allowing for their contribution towards peak demand during the week.

Modelling scenarios

We adopted six main scenarios, each of which consists of a number of sub-scenarios based on three flexibility criteria (power plant, storage and contract), the share of VRE and target years (Table 2.2). The flexibility criteria comprise power plant characteristics (MSL, ramp rates and start-up time), storage options and the flexibility of fuel supply contract and PPA.

The model considers different shares of VRE to explore its implications for flexibility requirements and the role of the flexibility options. The shares of VRE considered in the simulation accord with the 2018 PDP Revision 1 in 2025 and 2030. Meanwhile, an accelerated deployment of VRE is based on VRE targets for 2040 from the ASEAN Interconnection Masterplan Study (AIMS) III,[5] which are

[5] VRE targets from the AIMS III, under the ASEAN RE target scenario, stipulated 15% of VRE by 2040.

brought forward to be achieved by 2030. The capacity of wind and solar PV are therefore as follows (share of VRE in parentheses):

- PDP 4% in 2025: 3.6 GW solar PV and 1.7 GW wind capacity (4%)
- PDP 6% in 2030: 8 GW solar PV and 1.7 GW wind capacity (6%)
- ASEAN 15% in 2030: 18.8 GW solar PV and 6 GW wind capacity (15%).

For the accelerated VRE scenario in 2025, we assumed the share of VRE in 2030 as per the PDP (6%) is achieved in 2025. For the accelerated VRE scenario in 2030, we assumed the share of VRE in the 2040 ASEAN targets (15%) is achieved in 2030. In order to achieve 15% VRE uptake, 6 GW of wind is set according to the high renewable scenario in the 2018 Thailand RE Grid Integration Assessment since it reflects the true onshore wind potential in Thailand, considering site suitability. The solar PV capacity is set to fulfil the remaining VRE generation, resulting in about 19 GW of installed capacity. We based this on an average capacity factor of solar and wind plants of around 18% and 28% respectively.

Table 2.2 Modelling scenarios

<table>
<tr><th rowspan="2"></th><th rowspan="2">Scenario name</th><th rowspan="2">Year</th><th colspan="3">Key flexibility criteria</th><th rowspan="2">VRE share</th><th rowspan="2">Descriptions</th></tr>
<tr><th>Power plants</th><th>Storage</th><th>Contract</th></tr>
<tr><td rowspan="3">Base</td><td>Base 2025</td><td>2025</td><td>PDP</td><td>PDP</td><td>Existing</td><td>PDP 4%</td><td>• PDP Revision 1 in 2025</td></tr>
<tr><td>Base 2030</td><td>2030</td><td>PDP</td><td>PDP</td><td>Existing</td><td>PDP 6%</td><td>• PDP Revision 1 in 2030</td></tr>
<tr><td>Base 2030 ASEAN RE</td><td>2030</td><td>PDP</td><td>PDP</td><td>Existing</td><td>ASEAN 15%</td><td>• PDP Revision 1 in 2030
• ASEAN RE target</td></tr>
<tr><td rowspan="4">Power plant flexibility</td><td>MSL flex</td><td>2025, 2030</td><td>Flexible</td><td>PDP</td><td>Existing</td><td>PDP 4% (2025) PDP 6% (2030)</td><td>• Flexible MSL
• VRE targets based on PDP</td></tr>
<tr><td>Plant flex</td><td>2025, 2030</td><td>Flexible</td><td>PDP</td><td>Existing</td><td>PDP 4% (2025) PDP 6% (2030)</td><td>• Fully flexible power plants
• VRE targets based on PDP</td></tr>
<tr><td>MSL flex high RE 2025</td><td>2025</td><td>Flexible</td><td>PDP</td><td>Existing</td><td>PDP fast growth 6%</td><td>• Flexible MSL
• Accelerated 2030 VRE targets</td></tr>
<tr><td>MSL flex ASEAN RE 2030</td><td>2030</td><td>Flexible</td><td>PDP</td><td>Existing</td><td>ASEAN 15%</td><td>• Flexible MSL
• Accelerated ASEAN VRE targets according to AIMS III study</td></tr>
<tr><td rowspan="3">Storage</td><td>PSH_FS 2030</td><td>2030</td><td>PDP</td><td>PSH fixed speed</td><td>Existing</td><td>ASEAN 15%</td><td>• Fixed-speed PSH
• ASEAN RE target</td></tr>
<tr><td>PSH_VS 2030</td><td>2030</td><td>PDP</td><td>PSH variable speed</td><td>Existing</td><td>ASEAN 15%</td><td>• Variable-speed PSH
• ASEAN RE target</td></tr>
<tr><td>BESS 2030</td><td>2030</td><td>PDP</td><td>BESS</td><td>Existing</td><td>ASEAN 15%</td><td>• BESS options (400 MW/1.6 GWh and 800 MW/3.2 GWh)
• ASEAN RE target</td></tr>
<tr><td>Power plant flexibility and storage</td><td>Full flex 2030</td><td>2030</td><td>Flexible</td><td>PSH, BESS</td><td>Existing</td><td>ASEAN 15%</td><td>• All plants are fully flexible
• PSH and BESS
• ASEAN RE target</td></tr>
<tr><td rowspan="2">Contractual flexibility</td><td>Contract flex</td><td>2025, 2030</td><td>PDP</td><td>PDP</td><td>Flexible</td><td>PDP 4% (2025), PDP 6% (2030)</td><td>• Flexible gas take-or-pay contract in 2025 and 2030</td></tr>
<tr><td>Full flex with contract flex 2030</td><td>2030</td><td>Flexible</td><td>PSH, BESS</td><td>Flexible</td><td>ASEAN 15%</td><td>• All plants are fully flexible
• Flexible gas take-or-pay contract in 2030
• PSH and BESS
• ASEAN RE target</td></tr>
</table>

Notes: RE = renewable energy; FS = fixed speed; VS = variable speed.

For the scenarios with power plant flexibility in 2025, we assumed that selected EGAT-owned CCGT plants (including partially owned)[6] are retrofitted with more flexible operational characteristics. These plants amount to around 8 GW and account for 30% of total gas-fired generation capacity. Meanwhile, for 2030 scenarios, we assumed all of the conventional plants in the system to be either retrofitted or flexible new builds. The investment costs of retrofits are based on an

[6] Selected EGAT plants for retrofit are based on the CCGT plants that are owned (or partly owned) by EGAT. These plants include Bangpakong, Chana, Ratchaburi, RPCL, South Bangkok and Khanom power stations.

EGAT flexibility pilot project at a CCGT power plant in Thailand that aims to improve three key operational characteristics: MSL, ramp rate and start-up time (Table 2.3). The retrofit costs of the EGAT pilot project appear to fall within the range experienced by other projects internationally (shown in Table 1.2). For coal-fired power plants, using international data we assumed the retrofit costs to be four times greater than for CCGT.

Retrofit costs are annualised in order to compare them with simulated annual operational costs in the modelled year.[7] These retrofit costs are applied in the scenarios with retrofitted power plants regardless of age and configuration.

Table 2.3 Retrofit costs of key power plant flexibility parameters

	MSL		Ramp rate		Start-up time	
	CCGT	Coal	CCGT	Coal	CCGT	Coal
Cost of retrofit (million THB/MW)	0.044	0.18	0.066	0.26	0.095	0.38

The operating parameters of flexible power plants as compared to the existing plants for each technology are based on international data (Table 2.4).

Table 2.4 Average operating characteristics of conventional power plants by technology

	CCGT		CCGT (single shaft)		Coal	
	Existing	Flexible	Existing	Flexible	Existing	Flexible
MSL (% of capacity)	60%	30%	60%	30%	45%	20%
Ramp rate (MW/min)	~30	~60	~25	~50	~10	~30
Start-up time (hours)	~3	~1.5	~4	~2	~6	~2

For the storage scenarios, we considered a 3 x 267 MW (801 MW) PSH plant in the North-eastern region with a 10-hour storage duration and similar efficiency to the existing Lam Takhong PSH plant. The two PSH scenarios consist of PSH with a fixed speed (*PSH_FS 2030)* and a variable speed (*PSH_VS 2030*) to explore the potential benefits for intra-day peak shifting. The BESS scenario (*BESS 2030*)

[7] Annualised costs are calculated assuming an 8% discount rate and 25-year plant life.

considers 400 MW/1 600 MWh or an 800 MW/3 200 MWh battery to compare their relative effectiveness, deployed in the North-eastern region.

To model fuel supply contracts and PPAs, all scenarios adopt the existing constraints of daily contract quantities for gas offtake,[8] except for the *Contract flex* and *Full flex with contract flex 2030* scenarios. Additionally, the model has no mechanism to carry forward unused gas quantities to subsequent days. We also assessed the potential value of flexible fuel supply contracts without daily contract quantities in 2025 and 2030, both with and without plant flexibility (as discussed above), by removing any constraints on daily contract quantities. However, imported hydro take-or-pay obligations are maintained in all scenarios.

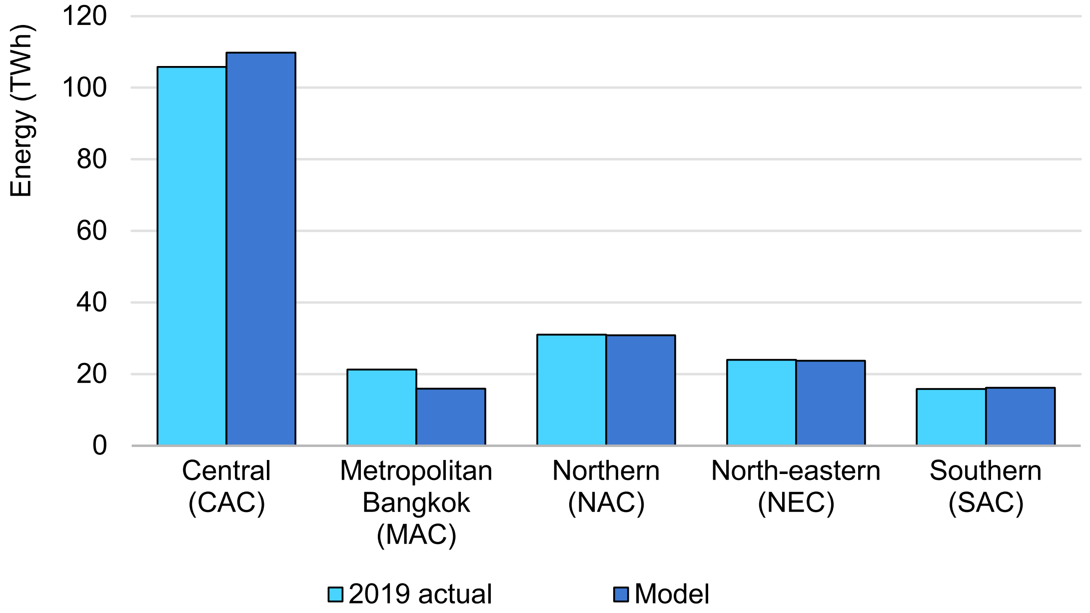
Note that the production cost modelling used in this study does not consider a full cost-benefit assessment over the lifetime of the flexibility options (power plants, PSH and BESS) and as the power system evolves over time. Capacity expansion modelling with cost-benefit analysis could be considered in future analysis.

Model validation

We validated the set-up of the production cost model against actual operation statistics from Thailand's power system in 2019. Total generation by region is very similar to the actual data (Figure 2.2), with only small differences in the total generation in both Central and Metropolitan regions, which are attributed to local transmission constraints that are not considered in the model.

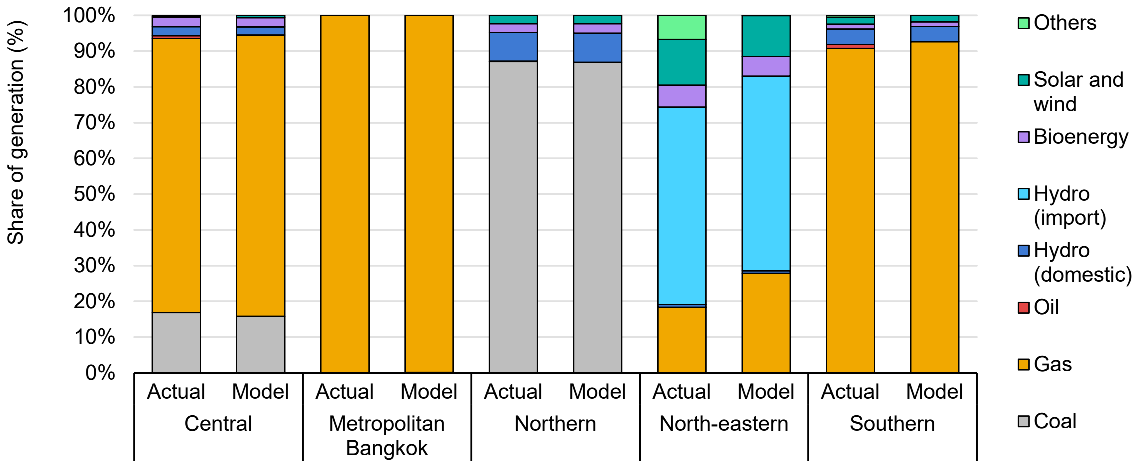
[8] Daily contract quantities represent a minimum take-or-pay requirement that is stipulated in long-term gas offtake agreements.

Figure 2.2 Total generation by region between the actual system and the model, 2019



Meanwhile, the share of generation by fuel type in each of the control regions produced by the model are also very similar to the actual data (Figure 2.3). The only noticeable difference is in the NEC region due to non-PPA imports from Lao PDR (designated *Others* in Figure 2.3) which accounted for less than 1% of supply in Thailand in 2019, but which is excluded from the model.

Figure 2.3 Share of generation between the actual system and the model, 2019



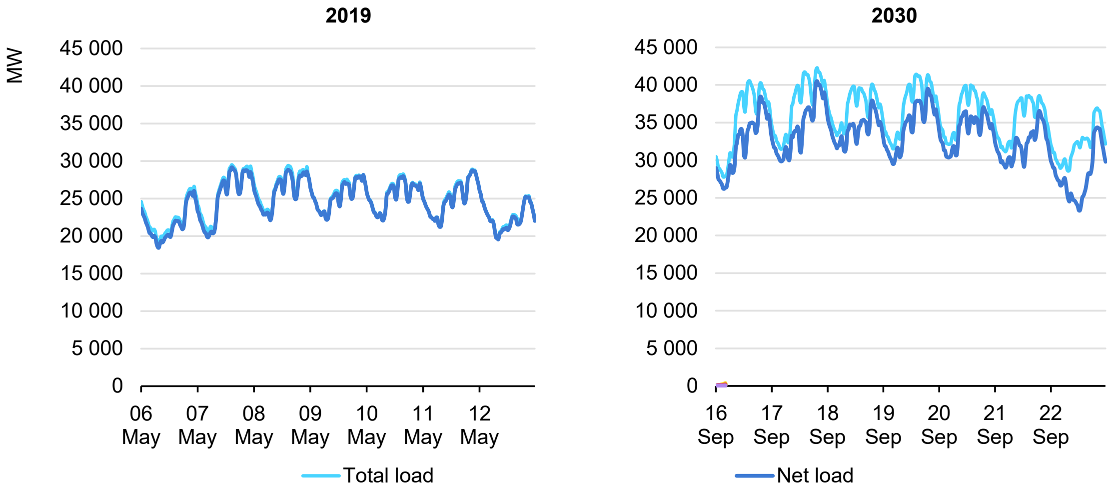
Analysis

Flexibility requirements in Thailand's power system

Several indicators point towards increased flexibility challenges. The net load ramping of the system (both hourly and sub-hourly) is a robust indicator of the flexibility requirement, considering the net load from the perspective of its variability. Another important indicator is minimum net load. Both ramping and minimum net load need to be met by flexibility sources, which nowadays come mainly from conventional generation and to some extent demand response, while storage is increasingly being deployed in global power systems. While smaller shares of VRE can be integrated into the power system using the inherent flexibility in the system, as the VRE share grows it is important to understand the flexibility requirements for the future power system.

The share of VRE in Thailand is projected to increase from just under 3% in 2019 to 6% in 2030, according to the PDP 2018, meaning that the net load profiles will become more variable (Figure 2.4). The maximum 30-minute ramping requirement in Thailand's power system, which typically occurs in the morning on weekdays, is expected to increase from around 2 400 MW (or 80 MW/minute) in 2019 to 4 400 MW (or 147 MW/minute) in 2030. The maximum hourly and 3-hour ramping requirements will also increase from 6 500 MW in 2019 to 9 000 MW in 2030, which is around 40% of the daily peak demand (Table 2.4). The share of VRE in 2030, according to the PDP, does not present a technical challenge for Thailand's power system in accommodating the 30-minute, 1-hour and 3-hour ramping requirements. Under normal conditions on the system, VRE generation will be fully utilised without any curtailment in 2030.

Figure 2.4 Load and net load profiles during the peak period in the base scenarios according to the PDP, 2019 and 2030



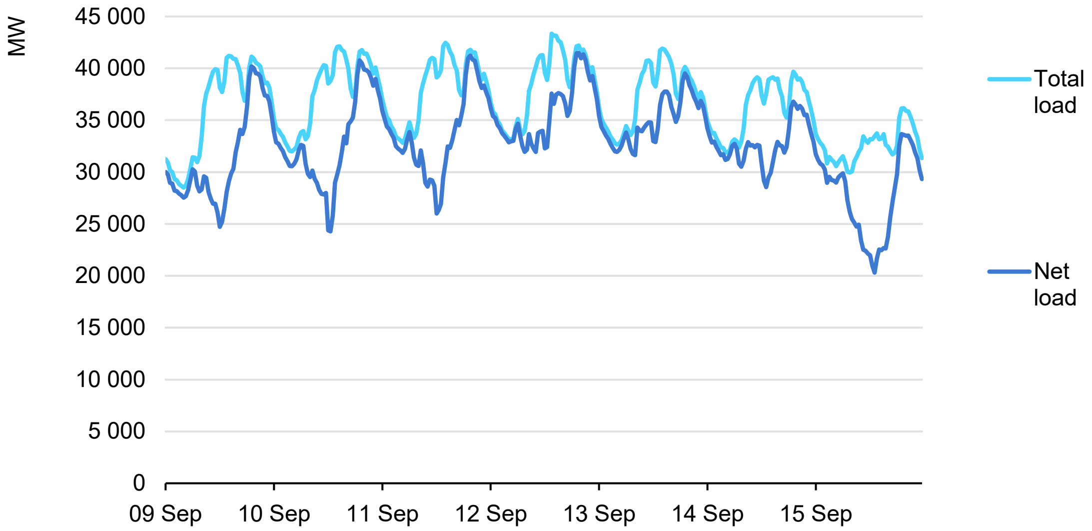
Notes: Net load = total load – (wind + solar PV + VSPP). Peak net load in 2030 is projected is shift to September due to the increase in non-dispatchable generation, particularly biomass.

Table 2.5 System ramping requirements in 2019 and in the base scenarios according to PDP, 2025 and 2030

	30 minutes			1 hour			3 hour		
	2019	2025	2030	2019	2025	2030	2019	2025	2030
Max daily ramp up (MW)	2 400	3 900	4 400	4 000	4 500	5 300	6 500	7 500	9 000
% of daily peak	9%	12%	11%	13%	18%	15%	21%	22%	37%
Max daily ramp down (MW)	2 518	6 400	7 100	2 900	8 100	8 950	4 829	9 900	11 000
% of daily peak	9%	20%	24%	10%	25%	24%	17%	31%	29%

In the accelerated ASEAN VRE scenarios, with a 15% share of VRE in 2030, the system faces greater variability in the net load profiles, which has implications for the power system's flexibility requirements (Figure 2.5). The power system experiences greater ramping requirements across different timescales. For the 3-hour period, the maximum upward ramp could reach 13 220 MW (73 MW/minute), which accounts for around 50% of the daily peak demand in 2030. The maximum ramping requirement usually occurs during low-demand periods, particularly in the holiday seasons. These ramping requirements are still technically manageable for the system given a reasonable share of hydropower and high share of CCGT. In other systems, such as California and India, 3-hour ramp rates can already be as high as 60-70% of the daily peak demand.

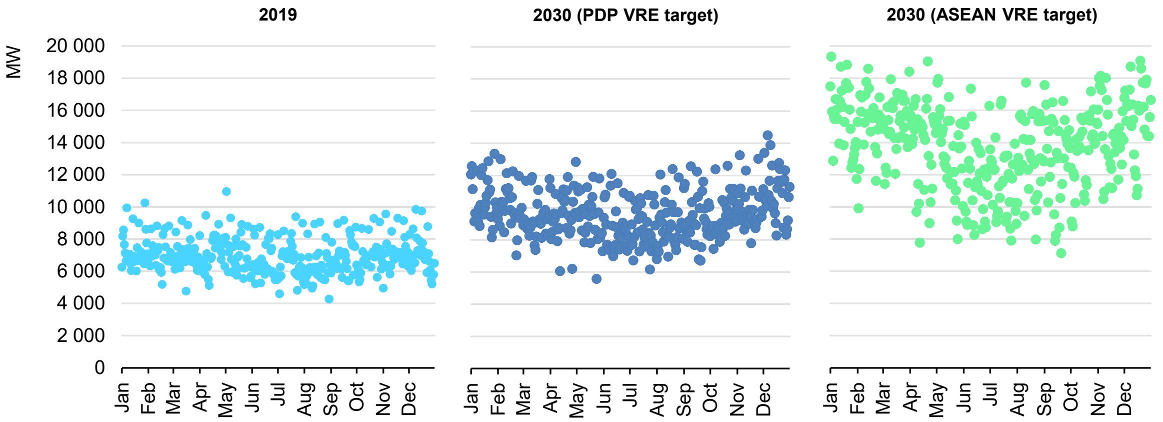
Figure 2.5 Load and net load profiles during the peak period under the accelerated ASEAN VRE scenario with 15% share of VRE in 2030



The gap between daily minimum and peak demand continues to grow. In 2019 the daily gap was in the range of 4-11 GW (up to 40% of daily peak). In 2030 this gap is projected to rise to 6-14 GW under the PDP scenario (50% of daily peak) and to 8-20 GW under the accelerated ASEAN VRE scenario (70% of daily peak) (Figure 2.6). The larger gap between minimum and peak demand leads to greater flexibility requirements and operational challenges that typically result in more frequent start-ups and shutdowns as well as cycling of conventional power plants, particularly CCGT given its large share in the generation mix. However, the system still possesses inherent technical flexibility to manage the increased flexibility requirements with changes to operational practices and additional flexibility options.

With the growing amount of VRE, particularly distributed solar PV, conventional power plants, which are the main source of flexibility, will need to provide even more flexibility to the system. Storage options, particularly BESS but also existing PSH, are also expected to play a more prominent role in the coming years. We explore these options in detail in the following sections.

Figure 2.6 The gap between daily net minimum and peak load, 2019 and 2030



The role of flexible power plants in accommodating VRE and semi-dispatchable generation

The operation of conventional power plants is constrained by the technical limitations of the specific generation technologies, including the MSL, ramp rate, start-up or shutdown times, and constraints on how often a generator can be cycled. Higher penetrations of VRE and other semi-dispatchable resources can lead to more frequent start-ups and shutdowns of conventional power plants due to greater variability in net demand. This can lead to increased start-up/shutdown costs and ramping costs (due to higher associated maintenance costs). These increased costs of conventional power plants need to be considered from a system point of view.

Potential benefits of power plant flexibility retrofits to the overall power system

In 2025 the capacity of retrofitted power plants that we selected for this study (~8 GW of EGAT-owned CCGTs) accounts for about 30% of total gas-fired generation capacity in Thailand (see the Modelling scenarios section). Meanwhile, by 2030 retrofits extend to all existing conventional thermal power plants, with new plants assumed to be constructed to a flexible design. We analysed the potential value and impact of each of the retrofit components (MSL, start-up time, ramp rates).

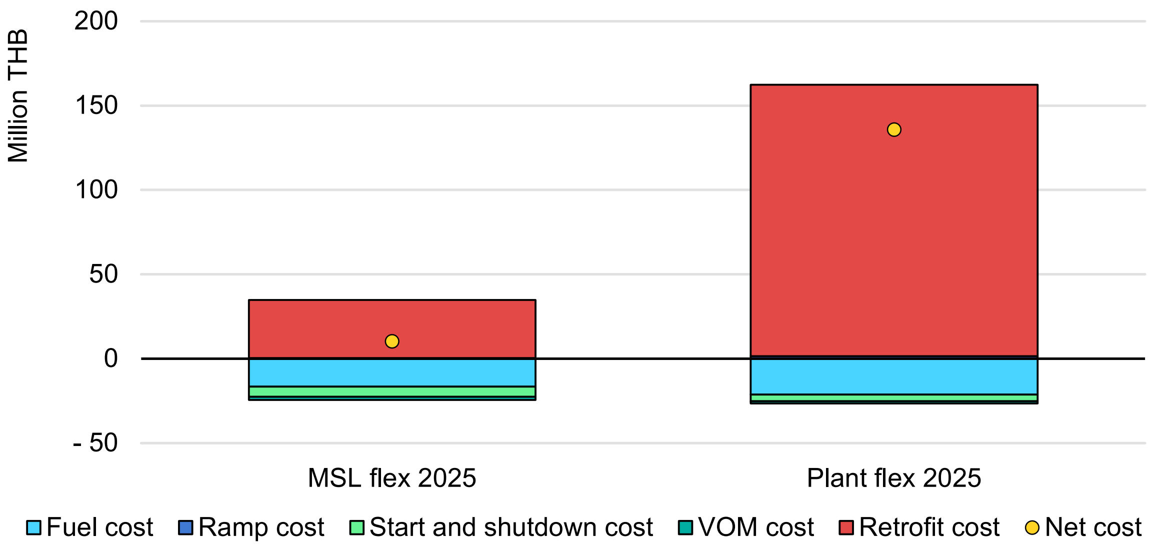
Results from the model runs for 2025 and 2030, with the 4% and 6% share of VRE as per the PDP and a number of existing constraints, particularly fuel contracts, show two main findings.

Firstly, operational cost savings from retrofits are limited, with savings of less than 0.02% (or THB 24 million from the total annual operational costs of around THB 190 billion) at the retrofitted power plants with lower MSL (Figure 2.7). Meanwhile, the retrofitting of plants to achieve higher ramp rates and shorter start-up times has a minimal impact in the model, achieving further savings of only about THB 1 million.

Secondly, the cost of plant flexibility retrofits far outweighs the operational cost savings in the short term (2025) when considering retrofits for all of the flexibility parameters and MSL only (Figure 2.7). The retrofit costs associated with improving the MSL are considerably lower than the costs to improve the start-up time and ramp rates (as indicated in Table 2.3). As a result, the annualised retrofit costs to improve only the MSL in 2025 are around THB 30 million, while it would require almost THB 140 million to improve all of the flexibility parameters. For 2030 scenarios where all conventional power plants are flexible, the annualised retrofit costs rise to around THB 150 million to improve just the MSL while the operational cost savings are still similar to 2025.

The operational impact of plant retrofits is insignificant to both the power plants and the overall power system. Annual generation and the number of start-ups of the retrofitted plants are almost the same as before retrofitting.

Figure 2.7 Operational cost savings relative to retrofit costs as a result of power plant flexibility in 2025



Notes: *MSL flex 2025* scenario only considers flexible MSL. *Plant flex 2025* scenario considers flexible MSL, ramp rate and start-up time. VOM = variable operating and maintenance.

Note that as the modelling is based on a 30-minute time resolution, instantaneous ramping constraints (less than 30 minutes) are not considered,[9] while for start-up time, only a limited representation is modelled.[10] These model limitations may mean that further very small operational cost savings and operational impacts could be observed when improving ramp rates and start-up times. Due to the model's limitation in properly measuring the benefit of shorter start-up times and faster ramp rates, we only consider lower MSLs for plant retrofits in the remainder of the report.

The benefit and operational impact of power plant flexibility as VRE deployment increases

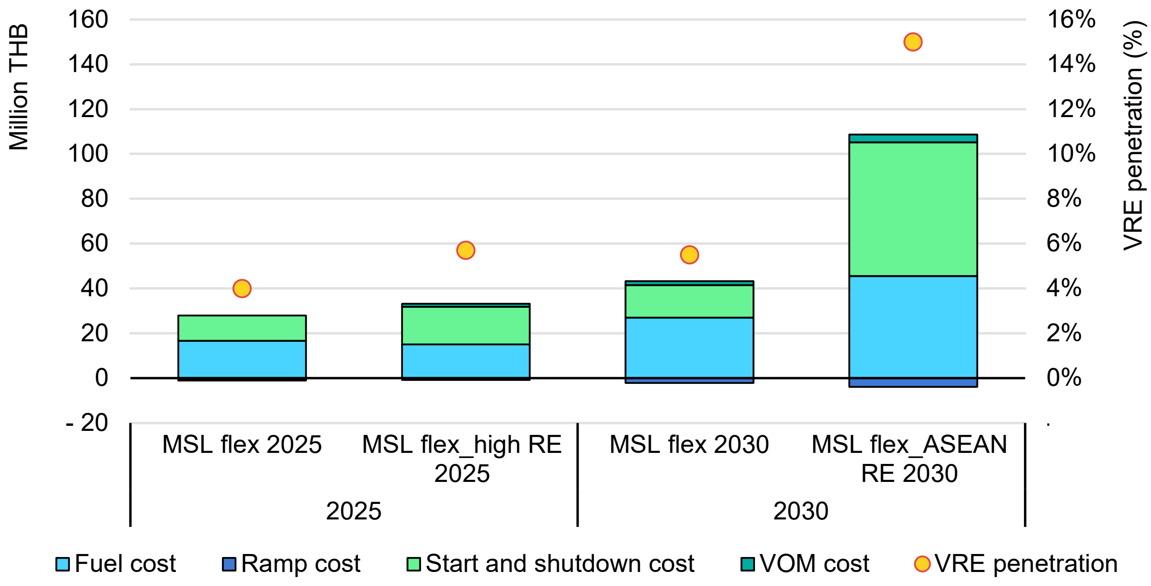
In evaluating the impact of higher VRE penetration on the Thai power system, as well as addressing the suitability of power plant flexibility, the analysis addresses two further dimensions. Firstly, it looks at how the power system is projected to evolve in the medium term towards 2030 as per the 2018 PDP, in terms of both supply and demand. And secondly, it also looks at additional scenarios in which there is an accelerated deployment of VRE. The high VRE scenario in 2025 (*MSL flex_high RE 2025*) assumes that the 6% VRE target for 2030 is accelerated. The ASEAN RE 2030 scenario (*MSL flex_ASEAN RE 2030*) assumes a 15% share of VRE, as detailed in the previous section.

With higher shares of VRE and greater variability in net load, the operational cost savings from power plant flexibility are expected to be more prominent since power plants are required to operate more flexibly in response to the increased variability in the supply–demand balance. We present the operational cost savings of the scenarios with higher VRE penetration in Figure 2.8.

[9] The benefit and impact of a higher ramp rate and faster start-up time could be underestimated due to the 30-minute time resolution of modelling. The model does not assess instantaneous ramping constraints, while it also excludes regulation reserves.

[10] The model only assesses real-time dispatch without considering multiple scheduling intervals (e.g. week-ahead, day-ahead or hour-ahead). Start-up time is based only on the run-up rate (ramp rate from zero output to MSL), while start-up notification time is not considered.

Figure 2.8 Annual operational cost savings as a result of power plant flexibility for 2025 and 2030 in both 2018 PDP and accelerated VRE scenarios

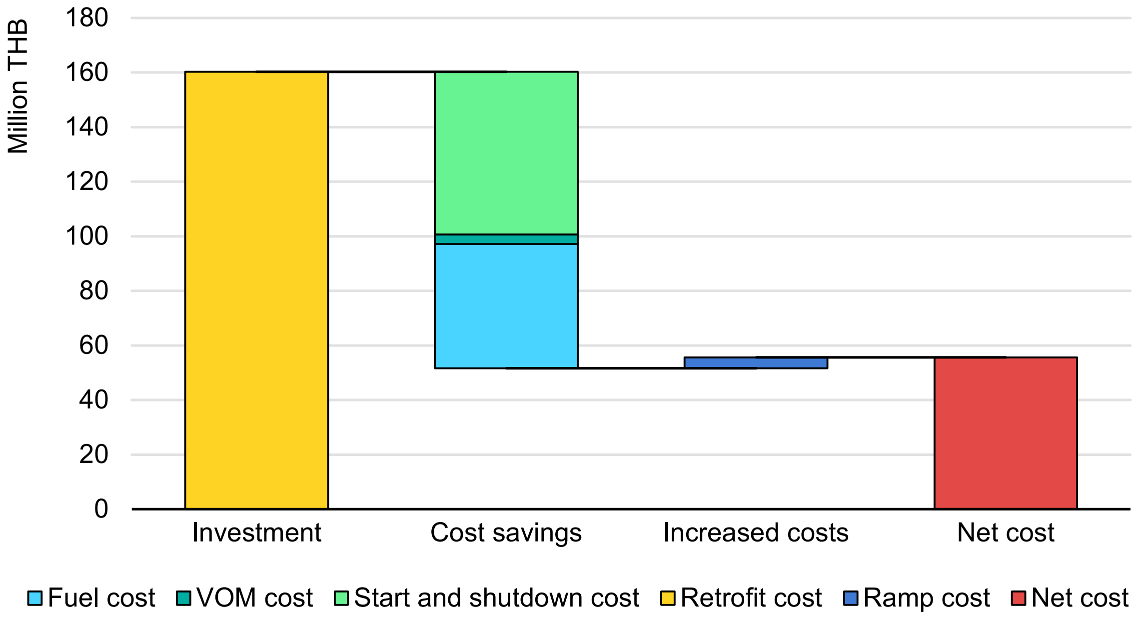


Note: *MSL flex* scenarios consider only flexible MSL parameter of power plants.

In all scenarios, the main cost saving components are fuel and start-up costs. With a lower MSL, conventional power plants can stay online during low load periods resulting in fewer start-ups and shutdowns, saving start-up fuel and avoiding auxiliary as well as wear and tear costs. With a 15% share of VRE in 2030, power plant flexibility reduces the number of unit start-ups by around 350 per year. Ramp costs, by contrast, slightly increase as plants have a greater range of operation (between MSL and maximum capacity) which allows them to lower their generation instead of shutting units down, leading to greater ramping up or down of their output. These savings are in line with an NREL study showing that the main proportion of cost savings comes from fuel and start-up/shutdown costs.

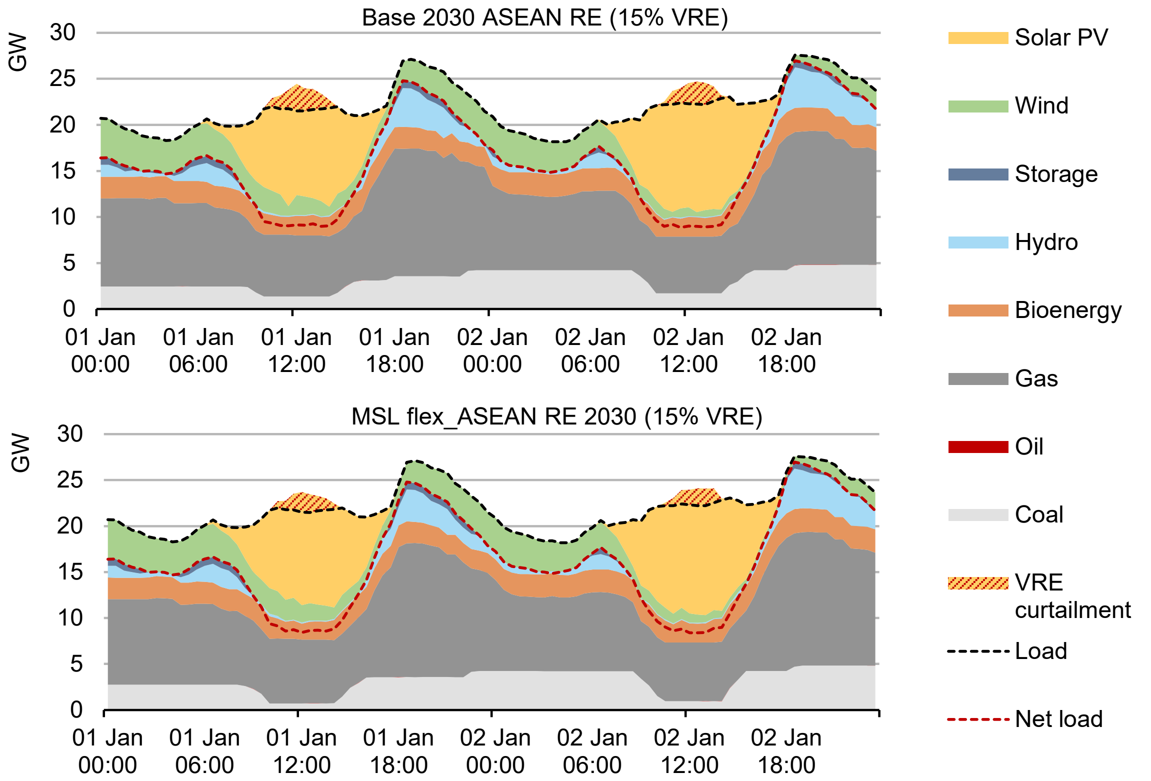
While the operational cost savings increase as the penetration of VRE increases in both modelled years, even in the ASEAN RE scenario in 2030 (15% VRE) where the most benefit is seen, cost savings amount to less than 0.1% of total operational costs. The annualised cost of retrofits to lower the MSL also outweighs the cost savings in 2030 by more than 30% (Figure 2.9). However, this only represents a single year while the retrofits represent a long-term investment over a 25-year lifetime. Therefore, we would expect the benefit in the following years to increase as VRE deployment grows, and even accelerate as the cost of wind and solar PV continues to decline. Additionally, further benefit may be found through targeted and/or staggered investment in retrofits based on flexibility needs.

Figure 2.9 Operational cost savings relative to retrofit costs as a result of power plant flexibility in the ASEAN RE scenario (15% VRE) in 2030



From a system operational perspective, the higher deployment of VRE, particularly solar PV, can create greater swings in net load between peak and off-peak periods. With a 15% VRE share under the ASEAN RE scenario in 2030, the annual VRE curtailment rate is just 0.05% (20 GWh), even with the current level of power plant flexibility in the system. VRE curtailment can only be observed during the New Year holidays when net demand is extremely low (Figure 2.10). Flexible power plants with lower MSL can contribute in reducing the level of VRE curtailment. In order to balance the system and maintain system security, the system operator should be able to curtail VRE, which is one of the last options after reducing generation output from other resources. We discuss the contractual aspects of curtailment in detail in the following chapter on contractual flexibility.

Figure 2.10 Generation by fuel type during the period of minimum net demand (1-2 Jan) in 2030 with 15% share of VRE (ASEAN RE) with flexible power plants



Note: *Base 2030 ASEAN RE* considers the current MSL; *MSL flex_ASEAN RE 2030* considers flexible MSL in all power plants in 2030.

With very low levels of VRE curtailment, the model suggests that Thailand's power system is technically capable of integrating as much as 15% VRE. Retrofitting the generation fleet to improve plant flexibility, which is a capital-intensive option, may not be a priority from a system perspective. Instead, efforts towards increasing flexibility should focus on "soft" interventions, which allow access to the inherent flexibility in the system through, inter alia:

- Appropriate system operation protocols to allow flexible operation of IPPs.
- Better inter-regional co-ordination.
- Better representation of renewable forecasting in system operation decisions, which reduces the uncertainty of renewable production between dispatch intervals.

Adding to this point, results from the model suggest that a large amount of flexibility can be accessed by addressing inflexibility in the daily contract quantities of long-term gas offtake agreements. The cost benefits of doing so far outweigh the savings from retrofits in both 2025 and 2030. Contractual flexibility can also help to derive greater benefits from retrofits, with additional savings on fuel costs as well as reduced cycling (and hence lower start-up and shutdown costs). We present a more detailed discussion of contractual flexibility in the following section.

The contribution of storage options to system flexibility

In the following subsection we explore the benefits of PSH and/or BESS in the context of the power system in Thailand in 2030, considering the more ambitious ASEAN renewable target (15% VRE). Note that our analysis does not consider the lifetime benefits of any storage option or its investment costs, nor does it offer a total system cost analysis. Instead, it offers an assessment of the operational benefits of both technologies. Our analysis is limited to the 30-minute resolution of the model and hence does not capture the potential benefits in the short timescale. Instead, our analysis is limited to the ability to use storage for energy arbitrage and peak shifting.

The evolving role of storage in Thailand

In order to evaluate the benefits of storage to Thailand’s system with a growing share of VRE, we modelled several scenarios to assess the benefit of both PSH and BESS.

We created a scenario whereby an additional 800 MW of PSH capacity in the North-eastern region is added to Thailand’s existing PSH capacity, all constrained by fixed-speed operations. Additionally, a further scenario looks at the benefit of this new PSH capacity being equipped with a variable-speed turbine, thereby allowing it to more accurately follow the subtle changes in the supply–demand balance by allowing it to both pump and generate from ~67% of its nameplate capacity.

As systems move towards more VRE, the role of PSH is also expected to change. In particular, the cycling of storage may begin to move from a weekly to a daily basis, especially with the rise in deployment of solar PV, which will lead to valuable opportunities to pump during periods of peak solar output (and minimum net load).

To compare the relative effectiveness of deploying BESS for peak shifting, we also modelled two further scenarios in which either a 400 MW/1 600 MWh or an 800 MW/3 200 MWh battery is deployed in the North-eastern region. The similar size and region of their deployment to that of PSH is for direct comparison; however, the less constrained nature of BESS means that they could be more flexible in both location and modularity. As opposed to PSH, which is limited to relatively large projects and specific geographies, BESS can be modular and more bespoke in design according to the needs of the system.

We present a summary of the modelled characteristics of both technologies in Table 2.6.

Table 2.6 Modelled technical characteristics of storage technologies

Modelled characteristic	PSH	BESS
Minimum pump load	100% (or 67% for VS)	n/a
Minimum stable level	67%	n/a
Storage duration	10 hours	4 hours
Round-trip efficiency	79%	90%

The value of storage to the future Thai power system

Results from the model show that installing 800 MW of new PSH in 2030 can potentially reduce the system's annual operational costs by around THB 60 million (less than 0.1%). The savings are primarily due to lower start-up and shutdown costs from conventional power plants, but are slightly offset by an increase in fuel costs since pumping load is likely to require additional generation from gas-fired generation on the system (Figure 2.11).

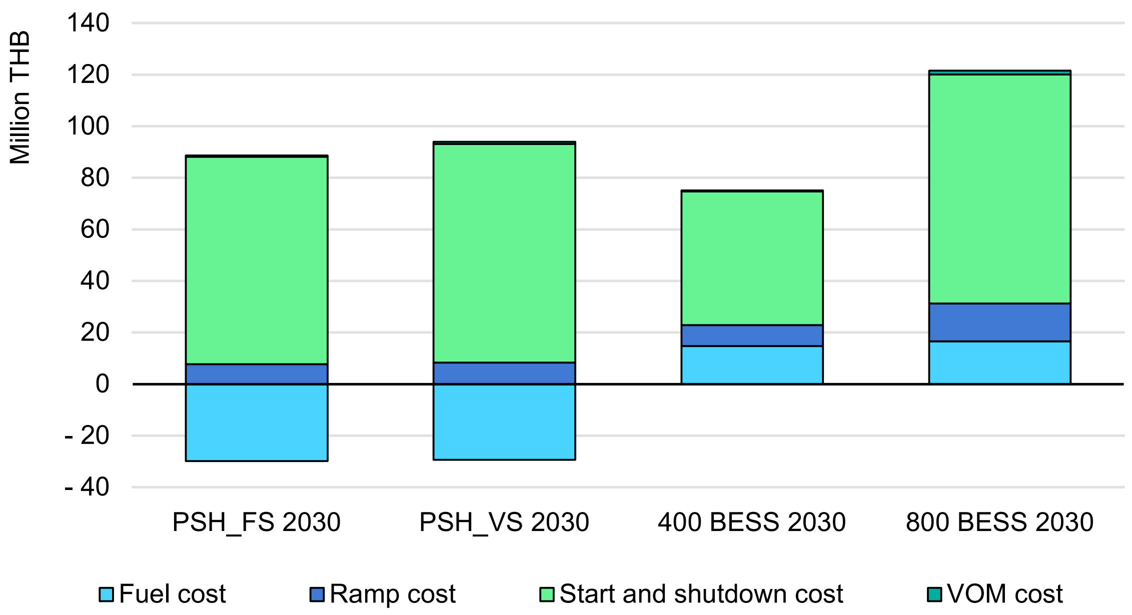
Furthermore, the difference in the cost savings between fixed-speed and variable-speed PSH at the share of VRE modelled in 2030 (i.e. 15%) is almost negligible. The marginal cost of a variable-speed PSH versus a fixed-speed PSH is less than 5% if amortised over the lifetime of the plant and assuming a discount rate of 10%. Since the analysis does not consider the benefit over the lifetime of the plant, the benefits are expected to improve year on year with a growing share of VRE.

The more flexible operational characteristics of the BESS results in more energy arbitrage opportunities and further cost savings. Installing a 400 MW battery would result in an annual operational cost saving of THB 75 million (less than 0.1%). With an additional 400 MW battery capacity (total of 800 MW in the North-eastern region), there are then an additional 60% of savings (THB 122 million), as it makes more efficient use of cheaper generation sources during off-peak periods and displaces more expensive peaking capacity.

These savings are still very small relatively and will not cover the investment cost. However, the benefits of storage deployment can extend beyond just operational cost savings.

While a cost assessment of both technologies is beyond the scope of our analysis, for perspective, deployment costs from 2020 for unsubsidised utility-scale 100 MW/400 MWh BESS range between USD 183 and USD 340/kW/year. Therefore, a rough estimate for 800 MW BESS would be THB 4.5-9 billion, which far outweighs the operational cost savings even at an accelerated VRE target of 15% in 2030. As Thailand's power system possesses inherent flexibility to integrate up to 15% VRE by 2030, investing in PSH and BESS should not be a top priority in the short to medium term.

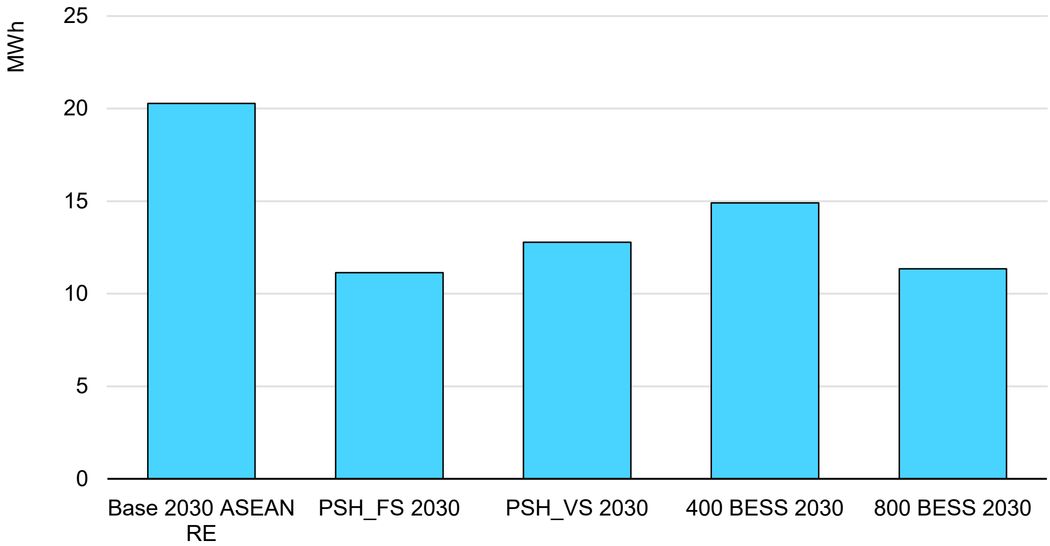
Figure 2.11 Operational cost savings with storage options (PSH and BESS) at 15% share of VRE in 2030



The introduction of 800 MW of PSH and BESS reduces the level of VRE curtailment in the model from 20 GWh in the case without storage (*Base 2030 ASEAN RE*) to just above 10 GWh (Figure 2.12). However, the levels of curtailment in all scenarios are very small (< 0.05%) and do not yet pose any challenge to the deployment of VRE with a 15% VRE target. The difference in curtailment between the scenarios with and without variable-speed pumping is also negligible.

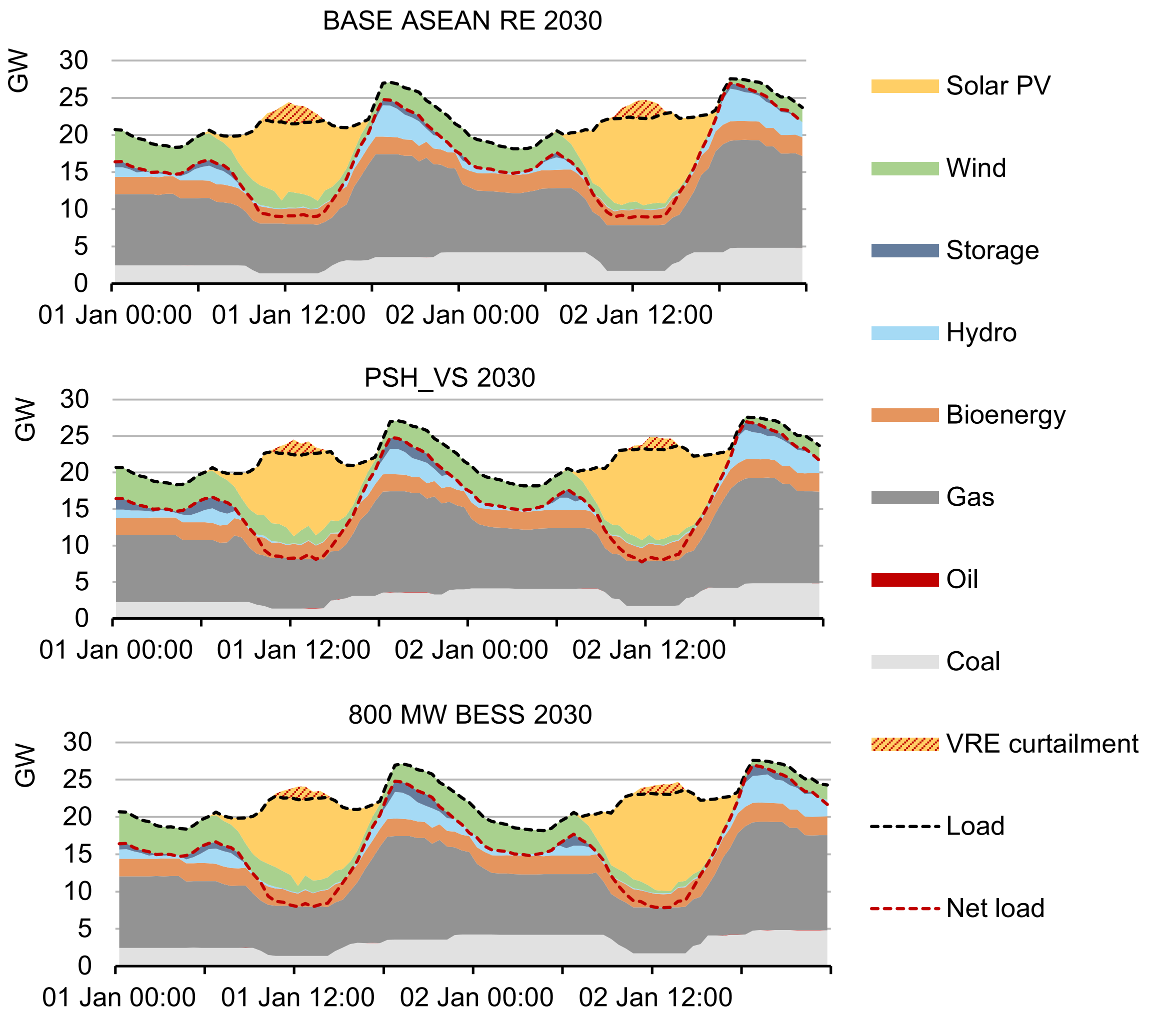
As discussed in the previous section, an appropriate mechanism should be in place to allow VRE curtailment, although it should only be performed as a last resort at critical moments. Therefore, avoiding curtailment of VRE generation should be a high priority in system operation decisions. A number of options are available to minimise VRE curtailment, such as improving forecasting systems and familiarising the system operator with VRE technologies and their characteristics. If curtailment is needed for reliability reasons, it should be carefully governed in PPAs by means of remuneration and processes. We discuss this topic in the following sections.

Figure 2.12 Curtailment of VRE in scenarios with different storage options included



The use of both PSH and BESS for peaking capacity can be observed in Figure 2.13, whereby the otherwise curtailed VRE generation is used to charge the BESS around midday and discharged during the evening peak. However, it is not necessarily just about reducing curtailment, as storage is also used to allow more stable and efficient operation of generation, reducing the cycling of generators.

Figure 2.13 Contribution of PSH and BESS in the period of minimum net demand



Interestingly, the BESS in both scenarios displace the use of the existing Lam Takhong PSH plant as they become a more efficient option for peak shifting due better round-trip efficiency (90%) relative to pumped hydro (79%). However, BESS do not displace it completely, as Lam Takhong PSH continues to be used for shifting load over longer periods across multiple days, especially during prolonged periods of low load such as those seen during the Thai New Year in April (Songkran) and over Christmas and New Year. BESS are also utilised approximately five times more than PSH, due in part to better efficiency, but also because of their more flexible operation across different timescales. This suggests that BESS may represent a more economical alternative to PSH for load shifting, especially as Thailand advances its VRE targets. However, both technologies offer different value cases, which are not fully represented in the model or calculated over their lifetime.

When looking at the peak utilisation of different generation capacity across all regions (Figure 2.14. and Table 2.7), certain peaking capacity using natural gas is completely displaced from annual production due to battery deployment (971 MW of capacity is displaced with an 800 MW battery), and to a lesser extent pumped hydro (298 MW of displaced capacity). This result suggests that strategic deployment of BESS designed for peak shifting may be capable of displacing whole peaking units or even plants from the main generating fleet in a more optimal generation mix at higher shares of VRE. However, this should be explored and appropriately analysed in both a capacity expansion plan and system adequacy study.

Figure 2.14 Generation duration curve showing the top 1% of utilisation of natural gas generators in Central-West (left), Central-East (centre) and Metropolitan (right) region

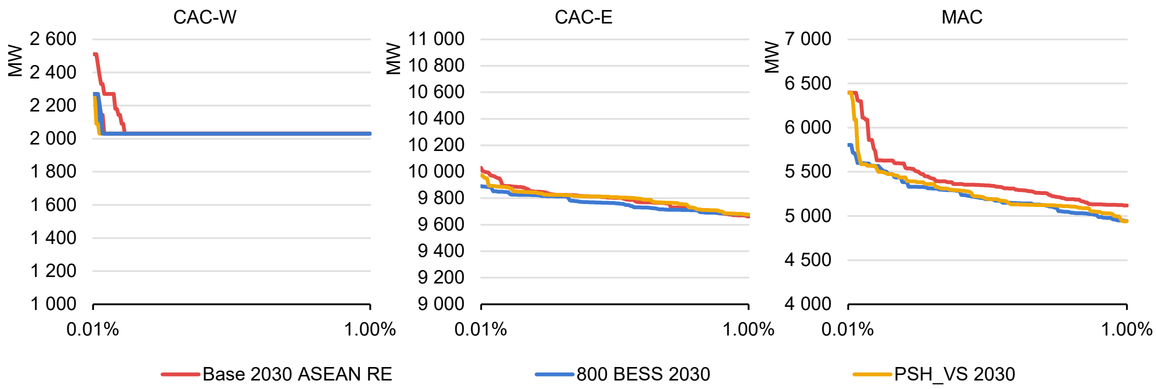


Table 2.7 Peak gas generation capacity utilised by region

Scenario	Peal gas generation capacity utilised (MW)							Displaced capacity (MW) (ref. to Base 2030 ASEAN RE)
	CAC-E	CAC-N	CAC-W	MAC	NEC	SAC	Overall	
Base 2030 ASEAN RE	10 030	6 501	2 510	6 397	1 530	3 806	30774	0
400 BESS 2030	10 006	6 501	2 270	6 269	1 530	3 806	30382	392
800 BESS 2030	9 893	6 501	2 270	5 804	1 530	3 806	29804	971
PSH_VS 2030	9 974	6 501	2 270	6 395	1 530	3 806	30476	298

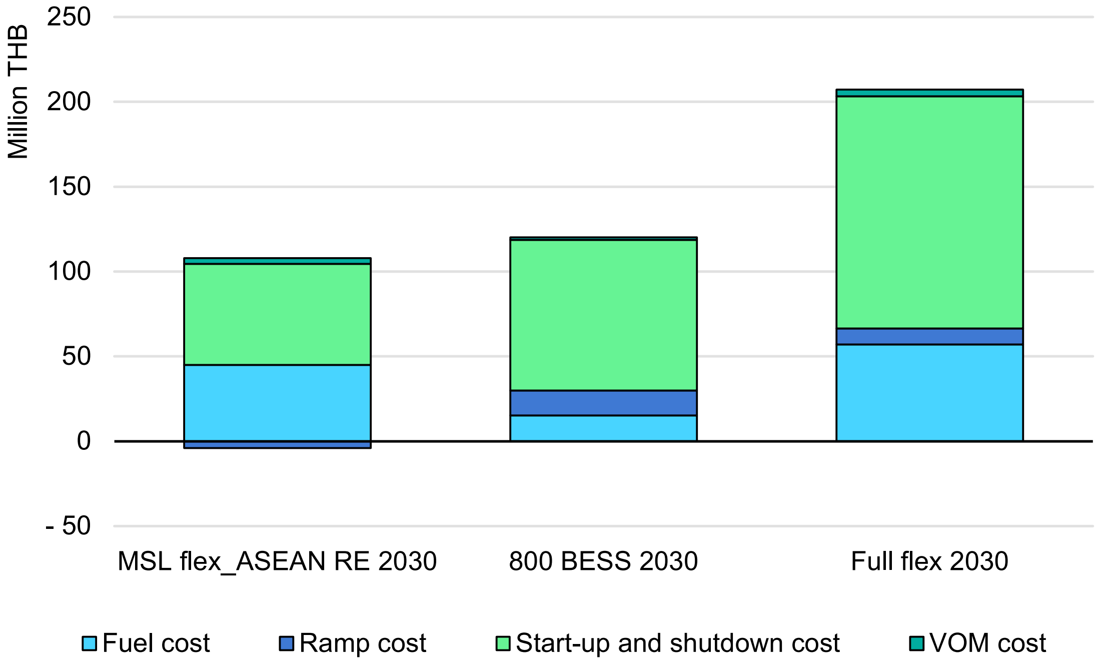
When comparing the results of pumped hydro and battery storage, besides the differences in technical design, it is also important to note the differences in modularity and lifetime. While the economic benefits of both options seem similar, the economic lifetime of a PSH plant is much longer (50 years vs 10 years), while BESS can be deployed in a more staggered manner given their modularity. This would allow future declines in storage costs to be captured and allow least-regret investment that leaves room for adaption as critical aspects of the power system change in the future – including demand shape, costs and generation mix. Note that certain system services that both technologies can provide are not captured within the production cost model, including black-start, fast frequency response and voltage control. Any selection of these technologies should therefore be assessed against the full spectrum of flexibility requirements.

The importance of a combined portfolio of flexible power plants and storage options

While this study has analysed the savings from each flexibility option in isolation, it is also of interest to evaluate the combined benefit of all flexible options (power plant flexibility, PSH and BESS) at a high share of VRE (15%). We therefore considered a further scenario (Full flex 2030) in which all conventional power plants (hydro and thermal generation) are flexible, and a new PSH plant and 800 MW BESS are both deployed in the North-eastern region.

Compared to the cases where only plant flexibility (with flexible MSL) or only an additional 800 MW battery are included, a combination of flexible power plants, PSH and BESS leads to operational cost savings of almost THB 210 million (> 0.1% savings), which is almost double the savings of any option on its own, showing the complementarity of the flexibility options (Figure 2.15). As noted in the previous sections, due to the inherent flexibility in the Thailand power system and the small cost savings that do cover the investment costs, there is still no cost motivation for deploying these flexibility options to accommodate shares of up to 15% VRE by 2030. However, as Thailand further accelerates its clean energy transition, the use of a combination of flexibility options could be considered to help achieve higher VRE deployment ambitions.

Figure 2.15 Operational cost savings from combined flexibility options at 15% VRE share in 2030



Similar to the scenario with only an additional 800 MW battery, the combined flexibility options lead to a decrease in the use of PSH, with around 50% less utilisation of both the existing Lam Takhong PSH and the new PSH plants in the North-eastern region. In fact, the new 800 MW/3.2 GWh battery is utilised 10 times more than the PSH plant, suggesting a more prominent role for BESS in providing flexibility with a growing share of VRE.

The majority of the savings come from a reduction in start-up and shutdown costs, with the remainder coming from a reduction in fuel, ramping and VOM costs. Fuel costs, however, make up the largest portion of generation costs. The relatively modest saving in fuel costs (< 0.1%) is tied to the contractual inflexibility of take-or-pay contracts that are still in place in 2030.

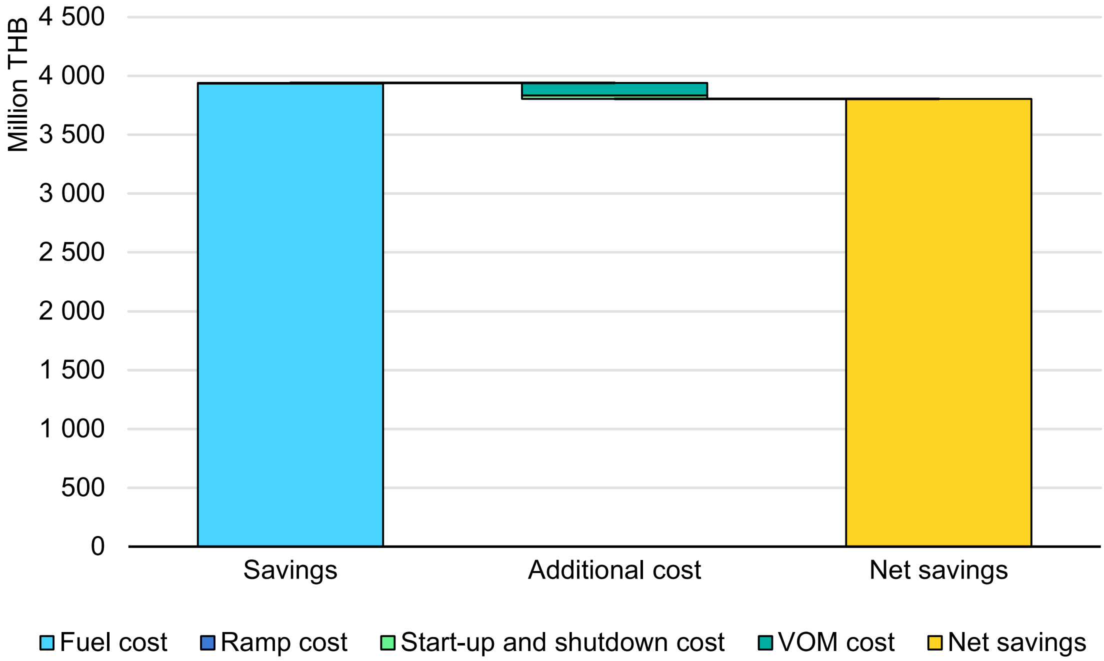
The implications of fuel supply contracts on technical flexibility options

Fuel supply contracts play a crucial role in unit commitment and dispatch decisions. Electricity generation in Thailand relies heavily on natural gas, with three main sources of gas: East Gas, West Gas and LNG. All the scenarios presented in the previous sections preserve the existing gas supply contract arrangement, which is subject to the minimum take-or-pay amount. The inflexibility of the existing gas supply contract restricts the economic dispatch of power plants so that the daily contracted quantity is consumed, which can lead to higher operational costs of the power system. This section provides an initial analysis of the potential benefits and technical implications of fully relaxing the fuel supply contract. It does not discuss issues related to the commercial considerations of and approaches to relaxing the contract obligations, as contractual flexibility is analysed in detail in the next chapter.

Relaxing the minimum take-or-pay obligations by 2025 could significantly reduce the operational costs of the system, by around THB 3.5 billion, or close to 2% of the total cost in the base case without any additional technical flexibility options (Figure 2.16). The reduction is largely driven by fuel cost savings as a result of avoiding non-merit order dispatch practice. When take-or-pay conditions are in place, gas-fired generators effectively become a sunk cost, and move down the merit order in line with renewables where the fuel is free. However, in practice the fuel is not free and needs to be paid irrespective of using it or not. This is why removing the constraint would place the gas-fired power plants in the correct place in the merit order according to their marginal costs.

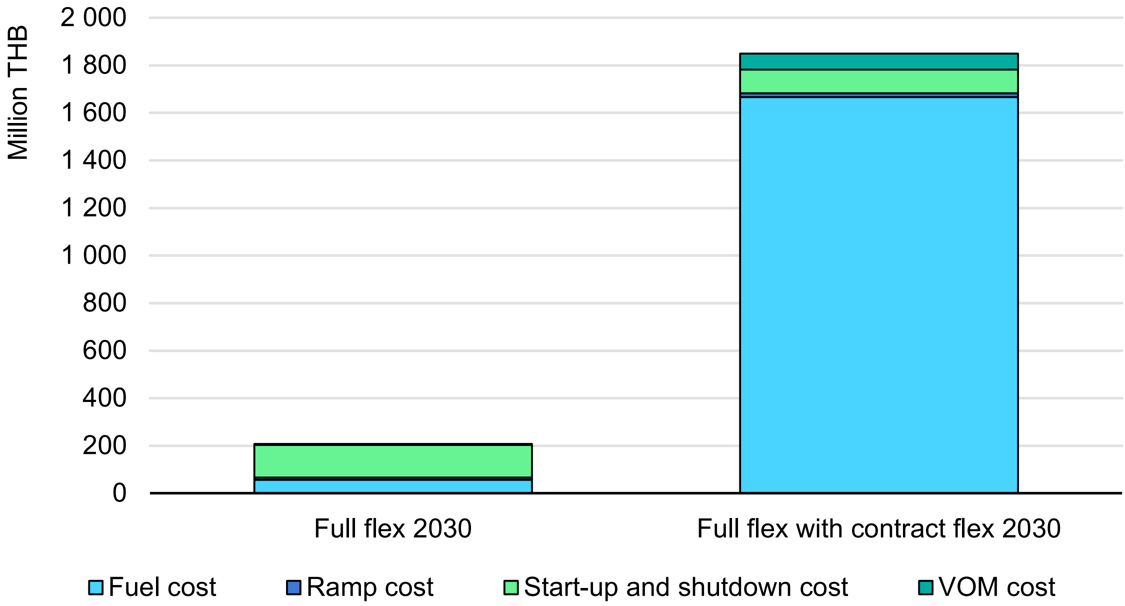
With a flexible fuel purchase contract in place in 2025 (*Contract flex* scenario), gas-fired power plants in the Central-West region become subject to expensive gas prices in the west (West gas) and are less often dispatched, allowing for greater utilisation of more economic generators. As a result, the system is truly based on merit order dispatch.

Figure 2.16 Cost savings from a flexible fuel supply contract in 2025



With a lower minimum take-or-pay quantity of gas under current arrangements in 2030 compared to 2025, the fuel cost saving from a flexible fuel supply contract in 2030 is less than the potential savings available in 2025. Compared with other technical flexibility options, the cost savings from a flexible fuel supply contract are significantly greater than the savings from flexible power plants and storage options combined (*Full flex 2030*) but with the existing fuel purchase contract (Figure 2.17).The amount of operational cost savings from a flexible fuel supply contract also far outweigh the retrofit costs to improve power plant flexibility, which are presented in the previous sections.

Figure 2.17 Operational cost savings from a flexible fuel supply contract in 2030 based on 15% VRE penetration



The flexibility of the fuel supply contract can potentially play a central role in reducing the cost of Thailand's future power system in both the short and medium term, more than all the technical flexibility options combined. However, relaxing fuel supply obligations is theoretical and may not be simple in practice as some form of obligation is normally required. However, with proper portfolio planning for generation and fuel supply, this should not create major inflexibility issues. We explore it in detail in the next chapter on contractual flexibility.

Recommendations for technical flexibility

We conducted the techno-economic analysis to assess the potential cost benefits of flexibility options to Thailand's power system in the short (2025) and medium term (2030) under different VRE penetrations. These options include power plant flexibility, PSH and utility-scale BESS. Our analysis shows that, under the current arrangement of Thailand' s power system, which still has a number of constraints, the rationale for investing in these hardware options is not clear.

The resulting recommendations for technical flexibility options are as follows:

- Retrofitting the generation fleet to improve plant flexibility is not justified given the cost of retrofits and the limited cost savings due largely to the fuel contract and PPA obligations, even at a 15% share of VRE in 2030.

- To avoid the cost of retrofits, changes to certain plant operational practices should be considered as an option to unlock power plant flexibility, with a focus on lowering the MSL, which is the most constrained dimension from a technical standpoint
- Power plant flexibility and storage options are complementary and may lead to more efficient operation of the system beyond 2030, allowing greater VRE deployment, which then leads to further cost savings.
- As Thailand further accelerates its clean energy transition, mobilising available technical flexibility may call for changes to operational practices and regulatory incentives to facilitate and promote the use of flexibility options and measures.
- Designing fuel supply and power purchase contracts with sufficient flexibility leaves headroom for lower-cost energy sources such as VRE, and assets that provide critical system services, to enter the market.

Contractual flexibility

Highlights

The analysis found that the minimum-take obligations in PPAs are too high, which affects the flexibility of the Thai system and negatively contributes to the operational cost of the system. The system will have significant amounts of over-contracted minimum-take volumes, especially in off-peak periods and when renewables are producing at high levels. For fuel contracts, an optimised way of purchasing gas would limit their inflexibility. In order to create more flexible fuel supply contracts, policy makers should take a portfolio approach and attempt to relax the current take-or-pay obligations. With this strategy, LNG may play a central role as LNG contracts are typically the most flexible.

The prevalence of contractual inflexibility creates the need to restructure contracts, which should be done with extreme care to ensure the future health of the investment environment in Thailand. If restructuring is not done very carefully investor confidence will deteriorate, which in turn will lead to higher required returns on investment, or in an extreme case a lack of investment. Damaging investor confidence thus has the potential to significantly increase the cost of the clean energy transition. One option to increase contractual flexibility would be to implement auctions in which selected contracts could be restructured. For example, if EGAT needed to increase start/stop limits, then an auction could be held with a new contract, and the auction price would be how much contract holders would need to be paid to switch to new and more flexible terms. A further recommendation is for Thailand to actively seek to develop the ASEAN multilateral power trade setup, such that imports of hydropower from Lao PDR, for example, can be used in a more flexible way.

Analysis

The importance of institutional and contractual structures

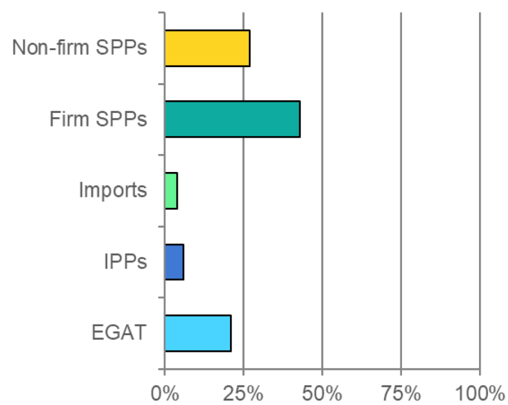
As previously noted, commercial flexibility plays an important role in allowing system operators to optimise their use of the flexibility that demand and generation assets can provide. In this report we define commercial flexibility as the flexibility provided by underlying contractual structures and institutions, which in the end facilitate the use of the technical flexibility. This section examines the need for increased commercial flexibility in the Thai system, both in PPAs and fuel supply contracts.

Overview of contractual obligations

Thailand's power system is based on an enhanced single-buyer model, where EGAT owns and operates the transmission system and a proportion of the generation. EGAT also holds PPAs with domestic IPPs (> 90 MW), SPPs (≤ 90 MW) and importing IPPs.

As the single buyer, EGAT sells wholesale electricity to Thailand's two distribution utilities, the Metropolitan Electricity Authority and the Provincial Electricity Authority, as well as a small number of direct industrial customers and utilities in neighbouring countries. Generators that are connected to MEA and PEA systems are called VSPPs (≤ 10 MW). VSPPs do not sell power to EGAT and as such are not in the scope of the study, but they do affect the net load seen by EGAT and therefore the amount of demand it needs to cover.

Figure 3.1 Thailand's PPAs by power generator, 2020

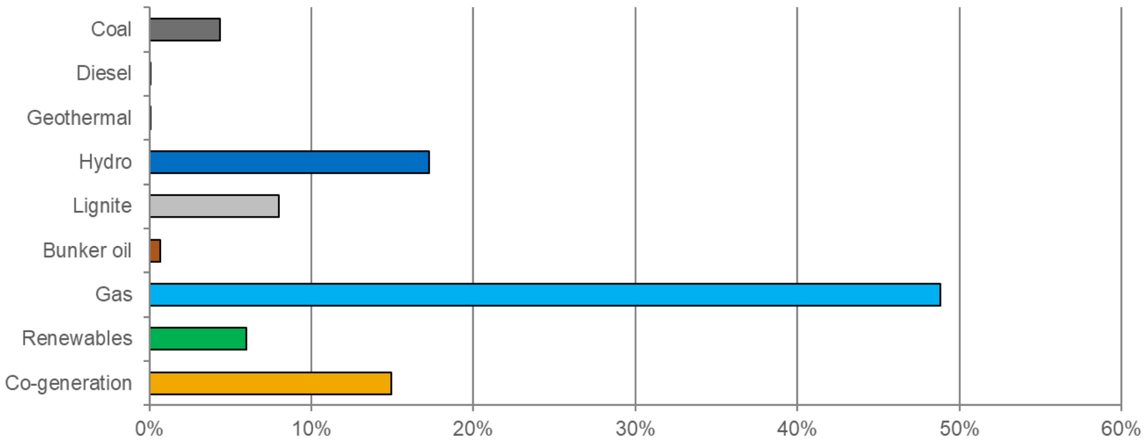


Source: EGAT.

A large percentage of the PPAs are contracted with SPPs.

EGAT has a contracted capacity of 46.3 GW, of which 49% is met by gas-fired generation (excluding SPPs). Hydro (domestic and imported) and co-generation are also important contributors to the system, with a share of 17% and 15% respectively.

Figure 3.2 Contracted power generation in Thailand, 2020



Note: Gas-fired generation capacity does not include SPPs.
Source: EGAT.

The majority of the contracted generation is from gas-fired power plants.

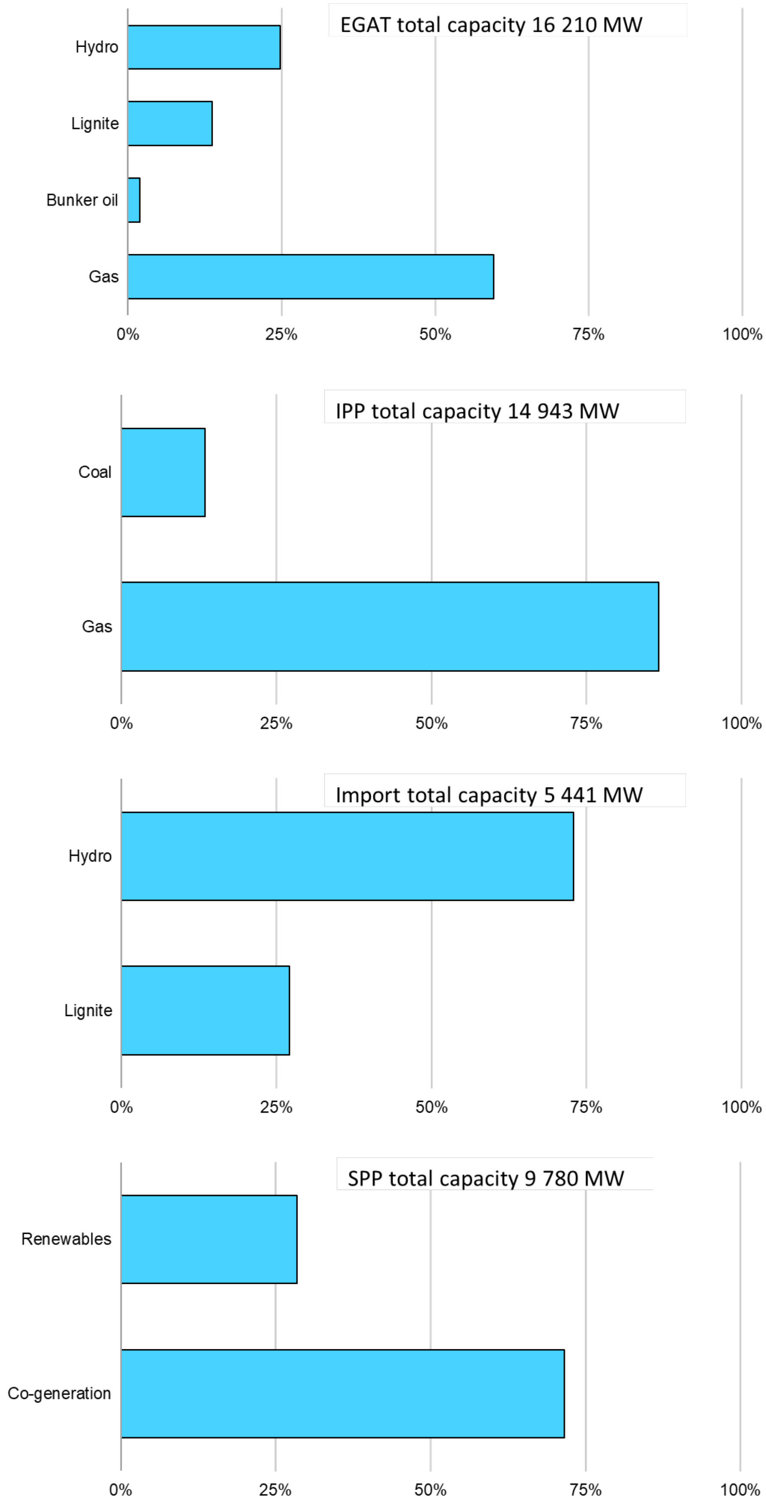
All IPPs are fully dispatchable subject to their contractual operational characteristics (e.g. minimum generation, ramp rate). Additionally, importing IPPs may benefit from minimum-take energy constraints that EGAT has to consider during its unit commitment calculations. The SPPs that make up a large proportion of the current PPAs can be classified into two types, firm and non-firm. Firm SPPs are dispatchable, but due to the minimum capacity factor constraint indicated in the contract, they are normally dispatched following a scheduled pattern with an MSL constraint. Non-firm SPPs are normally non-dispatchable. In other words, EGAT will take all the energy that they produce as long as the output does not exceed the contracted capacity. Thus, SPP non-firm contracts could be considered as "must-take" capacity. In brief, the main difference between firm and non-firm SPP contracts is whether they are dispatchable (at least on a scheduled pattern) or not.

The tariff structure that governs EGAT's payments to the generators differentiates between the type of generator (IPP, importing IPP, firm SPP and non-firm SPP). Firm contracts normally establish a two-part tariff that accounts for availability and electricity payments. In contrast, non-firm contracts just account for electricity payments. Depending on the technology and operating characteristics of the plant, additional tariffs and remunerations are paid (e.g. fuel saving, feed-in tariffs, renewable energy promotion, ancillary services).

The 2018 PDP projects renewables capacity to reach a share of 33% of the power mix by 2037, 20% from solar PV. In this context, it is important to ensure that the power system is resilient and flexible enough to integrate this increasing share of VRE.

Based on current levels of contracted capacity, EGAT and IPPs currently provide all the gas-fired capacity (excluding SPPs), which makes them important contributors to the system. EGAT provides all domestic hydro capacity, which accounts for around 50% of the total hydro generation capacity (domestic and imported). Imported hydro capacity is from the Lao PDR. Most renewable and co-generation capacity is provided by SPPs.

Figure 3.3 Contracted power generation capacity in Thailand by source, 2020

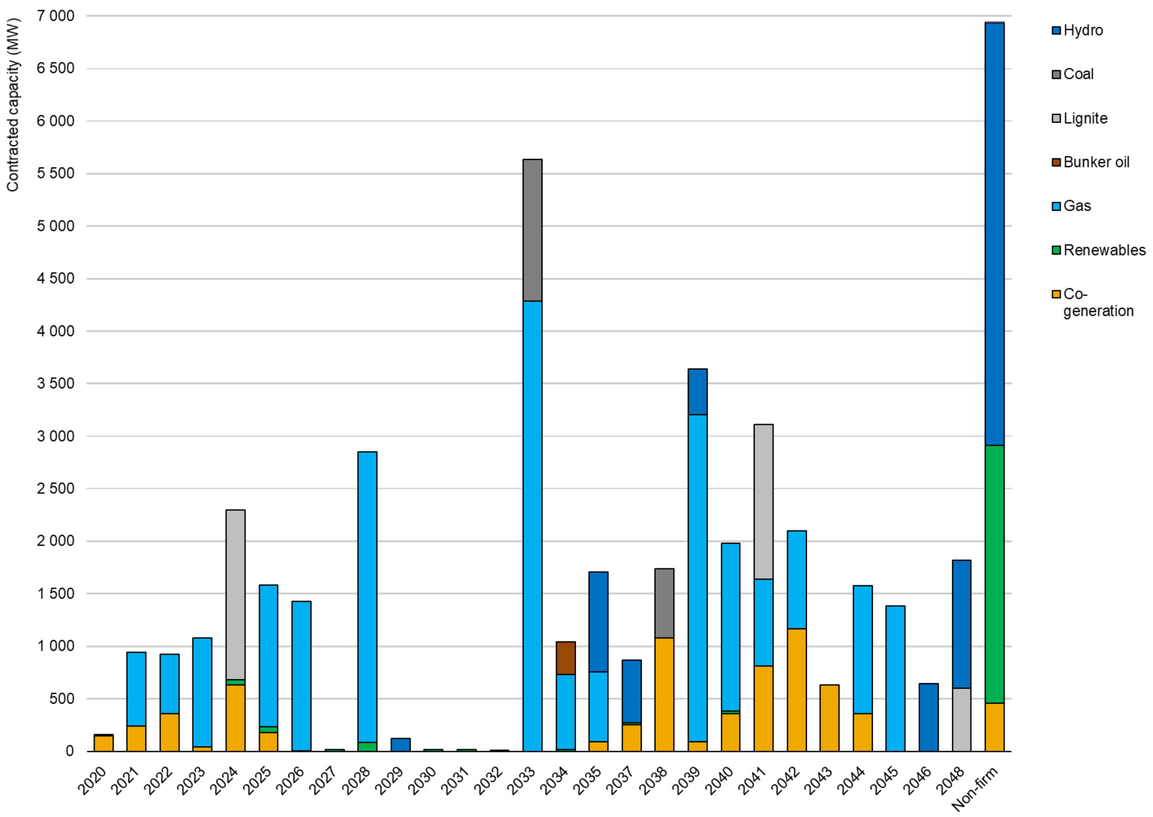


Source: EGAT.

Gas-fired plants are mainly owned by IPPs or EGAT.

Figure 3.4 provides an overview of the expiry of contracted generation by technology. The period between 2033 and 2045 is significant for the contractual expiry of conventional generation and co-generation capacity. In addition, all contracts for imported hydro capacity will expire between 2035 and 2048. It is important to keep these dates in mind, especially if greater contractual flexibility is required by the system before 2033. In that case, the figure below indicates which contracts can be renegotiated at expiry and which potentially should be restructured before expiry due to their extended duration.

Figure 3.4 Expiry of contracted power generation in Thailand

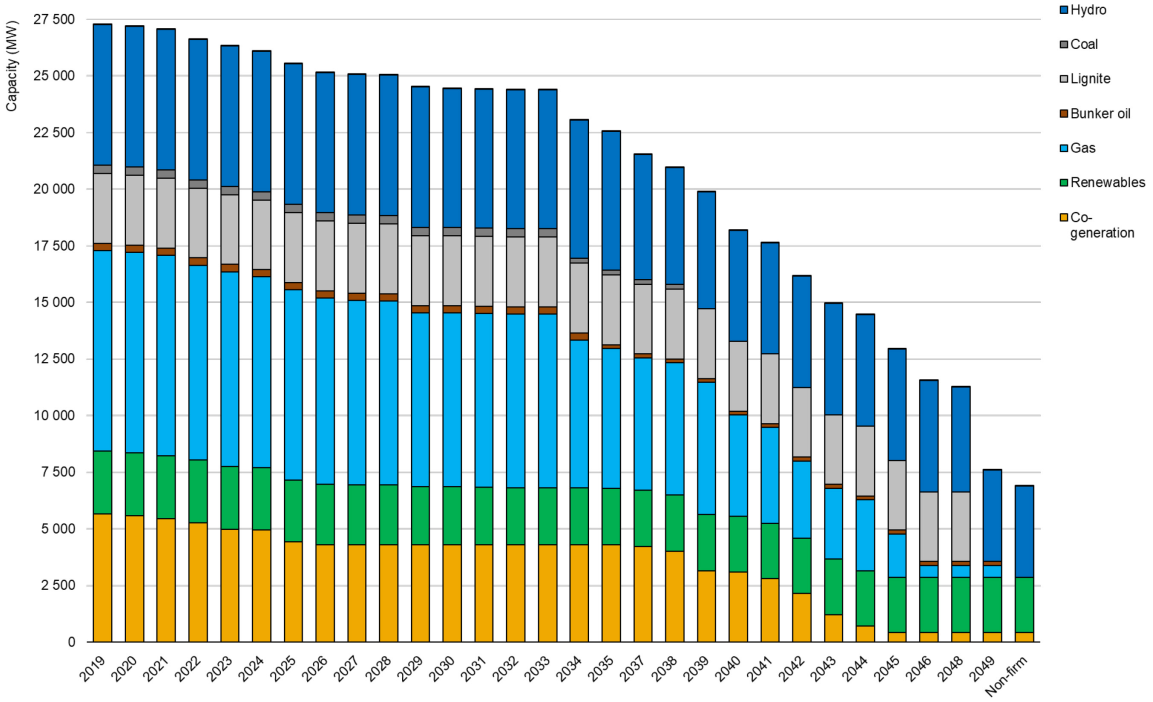


Note: Does not include imported hydro capacity (3 500 MW) and geothermal projects included in the 2018 PDP.
Source: EGAT.

Some gas and co-generation contracts expire before 2030, while no hydro expires before 2035.

As regards minimum-take capacity, Figure 3.5 shows its yearly evolution up to 2049 in the PPAs that are currently signed. For this study, we defined minimum-take capacity according to EGAT's dispatch criteria and the assumptions described in Table 3.1.

Figure 3.5 Yearly evolution of minimum-take capacity in all contracts



Source: EGAT.

Minimum-take capacity only starts to significantly decline after 2034.

Minimum-take capacity is currently dominated by gas (33%), imported hydro (23%) and co-generation (21%). The trend shows that minimum-take contracted capacity from gas-fired generators and co-generation will decrease over the years until reaching a minimum presence in 2046. Conversely, more than half of hydro's current minimum-take capacity will stay active.

Table 3.1 Assumed minimum-take capacity by technology

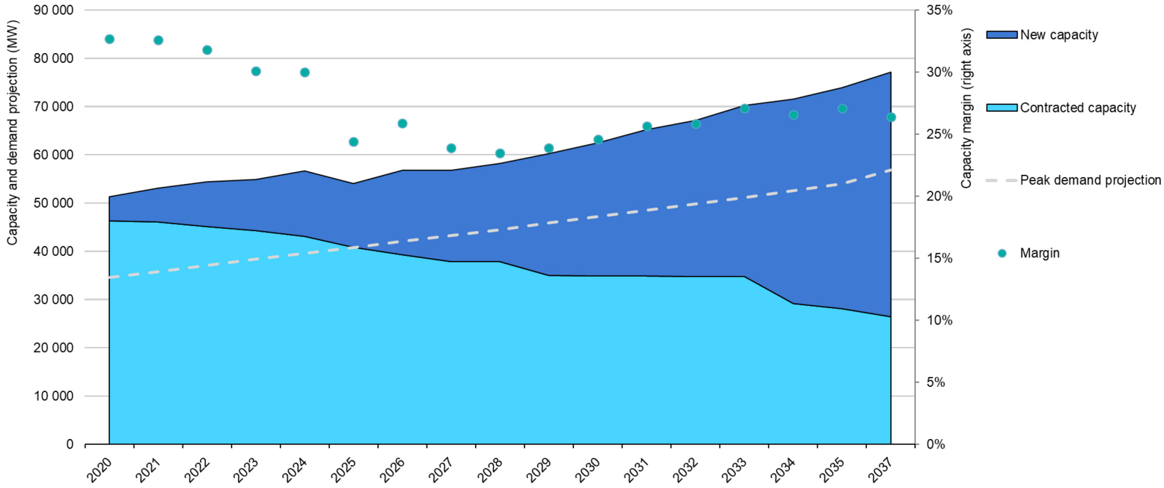
Technology	Minimum-take capacity
Co-generation (firm)	100% (peak) and 65% (off-peak) of declared capacity
Co-generation (non-firm)	100% of declared capacity
Renewables (firm and non-firm)	100% of declared capacity
Gas, bunker oil, lignite, coal, hydro (imports)	Minimum generation of declared capacity per unit
Geothermal	100% of declared capacity
Diesel	None
Hydro (EGAT)	100 % of declared capacity

The assumed minimum-take capacity as shown in Figure 3.5 forms the basis of our analysis of commercial flexibility throughout this chapter. The minimum-take obligations above were supplied by EGAT, and thus represent the restrictions it has in its PPAs.

Analysis of PPA obligations

The 2018 PDP provides an overview of the capacity that is expected to come online in the future. Even if the current contracts that are set to expire are not renewed, the Thai system will retain a significant capacity margin.[1]

Figure 3.6 Capacity margin in the Thai power system, 2019 to 2037



Note: Capacity includes VRE and is not adjusted by capacity factor; this means that the capacity margin reflects a situation where all generation produces at full capacity.
Source: EGAT.

Thailand's capacity margin remains above 20% beyond 2037.

Figure 3.6 shows that even though contracted capacity is set to decline, new capacity is expected to come online to meet Thailand's rising demand. While the reserve margin declines from above 30% in 2020 to just above 25% in 2037, it remains relatively high compared to international standards, which are around 10-15%.[2]

The 2018 PDP shows that the planned increases in renewable energy will be enough to meet the future growth in power demand. The combined share of hydropower, co-generation and conventional generation is projected to stay

[1] Capacity margin = (contracted capacity minus peak demand)/contracted capacity.
[2] The capacity credit of wind and solar PV may need to be considered when calculating the reserve margin.

almost constant during the period covered by the PDP (2018–2030). It is important to assess whether the system will provide enough flexibility to accommodate this increasing share of renewables. We created several scenarios to assess the flexibility that is likely to be needed from a contractual perspective. The changing factor in each of them is the availability of renewable energy on the system. The scenarios are constructed to reflect a potential time when the system would be stressed by low consumption and high renewable generation and vice versa. This has yet to happen on the Thai system, but it could potentially, and the scenarios act as a stress test to assess the flexibility that is needed in extreme scenarios. Table 3.2 provides an overview of the different assumptions in the scenarios.

Table 3.2 Assumptions for flexibility stress test scenarios

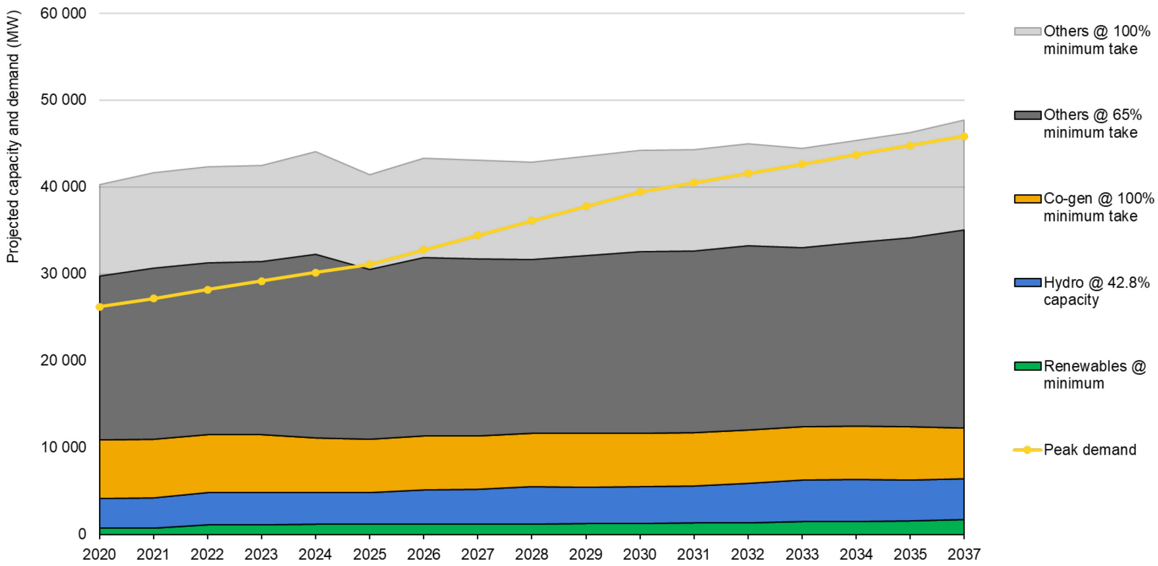
Scenario		Level of resource availability and minimum-take obligations for conventional generation and co-generation			
		Renewables	Hydro	Conventional generation and co-generation	Demand
1	Normal VRE scenarios	Minimum: per lowest capacity factor for wind (12.4%), solar (0.8%) and biomass (2.4%) Date: 26 Oct 2019 07h30 Capacity based on PDP developments	% of hydro capacity available during this period (42.8%)	Co-gen @ 100% (peak) Conv. gen @ 65%	Peak *
2				Co-gen @ 65% (off-peak) Conv. gen @ 65%	Off-peak *
3		Maximum: per highest capacity factor for wind (100%) and solar (93.5%) Date: 7 December 2019 13h00 Capacity based on PDP developments	% of hydro capacity available during this period (55.2%)	Co-gen @ 100% (peak) Conv. gen @ 65% and 45%	Peak **
4				Co-gen @ 65% (off-peak) Conv. gen @ 65% and 45%	Off-peak **
5	High VRE scenarios (6 GW wind and 19 GW solar by 2030)	Minimum: per lowest capacity factor for wind (12.4%), solar (0.8%) and biomass (2.4%) Date: 26 October 2019 07h30 Capacity based on PDP developments	% of hydro capacity available during this period (42.8%)	Co-gen @ 100% (peak) Conv. gen @ 65%	Peak *
6				Co-gen @ 65% (off-peak) Conv. gen @ 65%	Off-peak *
7		Maximum: per highest capacity factor for wind (100%) and solar (93.5%) Date: 7 December 2019 13h00 Capacity based on PDP developments	% of hydro capacity available during this period (55.2%)	Co-gen @ 100% (peak) Conv. gen @ 65% and 45%	Peak **
8				Co-gen @ 65% (off-peak) Conv. gen @ 65% and 45%	Off-peak **

* Maximum and minimum demand during 26 October 2019 (minimum demand 04h00 to 04h30 and maximum demand 07h00 to 07h30).

** Maximum and minimum demand during 7 December (minimum demand 03h30 to 04h00 and maximum demand 06h30 to 07h00). Off-peak timing in Thailand varies according to the season, and are not fixed night-time hours.

Scenario 1 represents a situation where renewables are producing at low levels during the peak demand period. Minimum-take obligations are relatively high in the peak demand period, with minimum-take of co-generation set at 100% and conventional generation at 65%. Figure 3.7 shows that the minimum-take obligations exceed peak demand even in a case where renewables are producing very little. After 2026 this is no longer an issue, and firm contracts will have to be activated to meet peak demand. If the corresponding scenario is analysed with off-peak demand then the issue of over-contracted minimum-take capacity worsens (Figure 3.8).

Figure 3.7 Scenario 1: Low renewables with peak demand

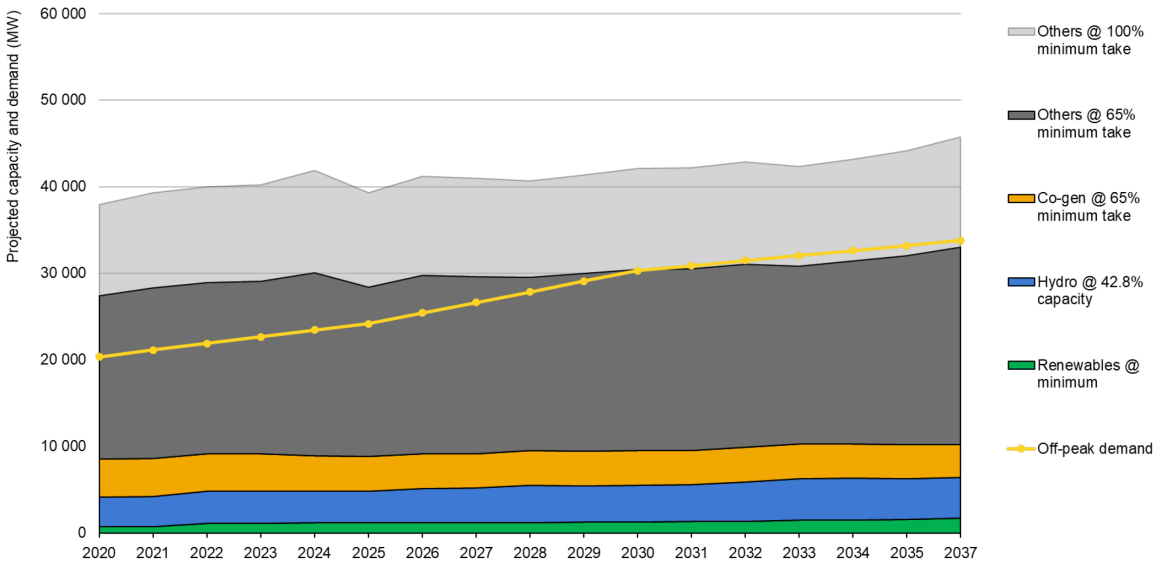


Note: Others covers gas, lignite, coal, other imports and energy conservation measures. The inclusion of others at 100% is to show what would happen if minimum-take obligations were higher.
Source: EGAT.

Until 2026 there is a potential lack of downward flexibility during the peak.

Looking at Scenario 2, the minimum-take quantity from co-generation falls to 65% (Figure 3.8). However, this is not enough to offset the lower demand that is experienced in the off-peak period, which means that the minimum-take generation exceeds demand until 2030.

Figure 3.8 Scenario 2: Low renewables and off-peak demand



Source: EGAT.

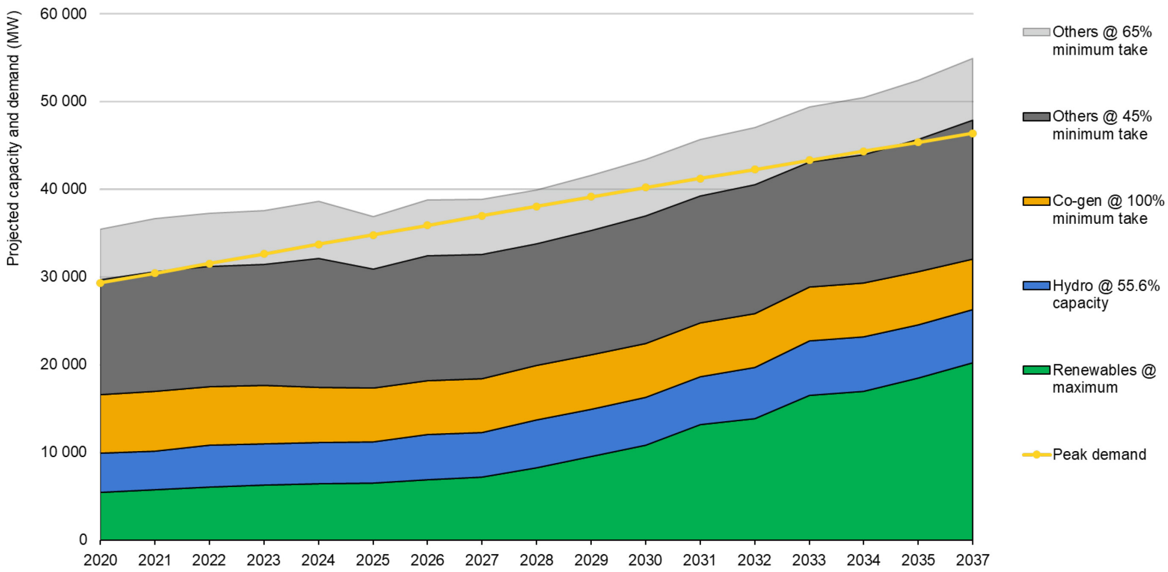
In the off-peak period there is a potential lack of flexibility until 2030.

Scenario 3 is a high renewable generation case. In this case peak demand is taken from the day with the highest renewables generation in 2019, to reflect the fact that there may be some seasonality that affects peak demand. Thus, it is important to note that the peak and off-peak demand in Scenarios 1 and 2 are not the same as the demand used in Scenarios 3 and 4. Figure 3.9 shows that the peak demand in the high renewables scenario (06h30 on 7 December) is significantly higher than in the low renewables scenario (07h00 on 26 October).

This suggests a positive correlation between renewables production and electricity demand, which for example would be the case with cooling demand rising in the dry season, which sees greater insolation. In the technical flexibility section it is shown that solar PV (for example) covers the higher demand in the middle of the day; however, the evening peak load is not covered by solar PV generation, which is why the flexibility of the system is important. It can also be seen that the demand absorbs most of the minimum-take generation during the peak. There may be minor excess generation from 2020 to 2022, and then again from 2034 to 2037; however, these should be manageable by dispatching hydro resources, for example.

The picture does change for the high renewable generation case when off-peak demand is considered (Scenario 4).

Figure 3.9 Scenario 3: High renewables and peak demand

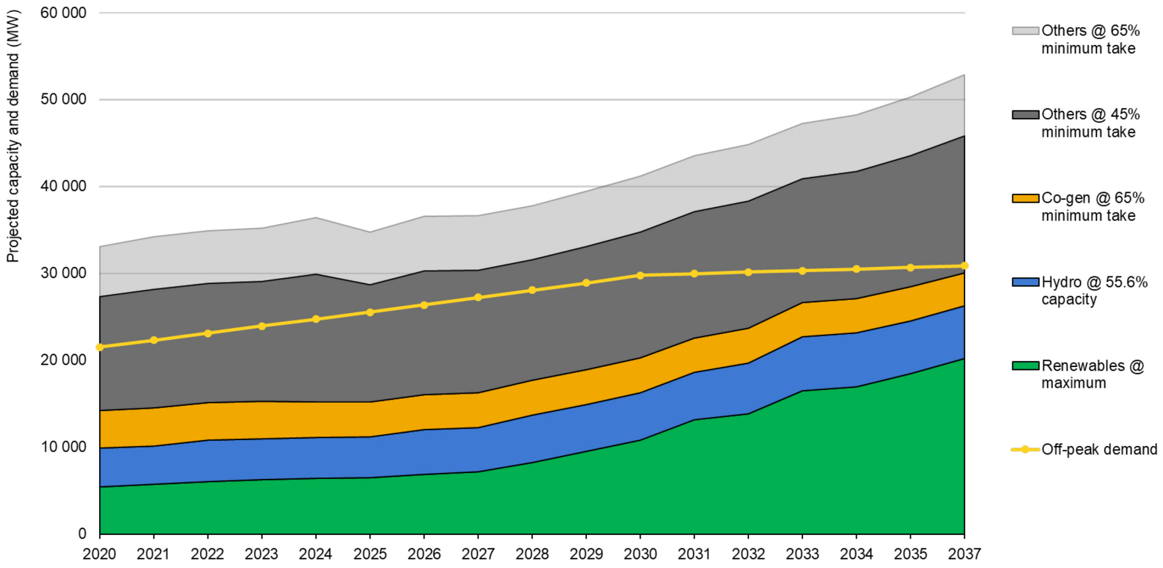


Source: EGAT.

In Scenario 3 peak demand is significantly higher than in Scenario 1.

As can be seen in Figure 3.10, in Scenario 4 (during the off-peak, which is 03h30 to 04h00) the minimum-take obligation is higher than demand in the entire analysis period. Taking Scenarios 2 and 4 together, it is quite clear that the off-peak in particular has issues with downward flexibility due to minimum-take obligations that are too high. This signals that urgent action has to be taken to ensure that any new PPAs with conventional generation and potentially also co-generation take this problem into account.

Figure 3.10 Scenario 4: High renewables and off-peak demand

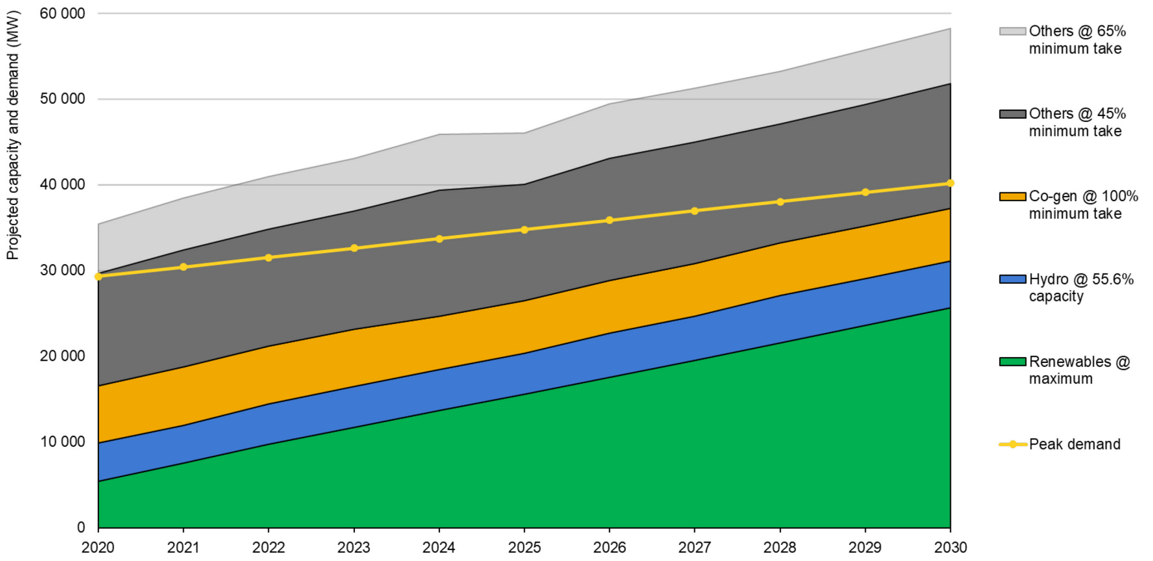


Source: EGAT.

In Scenario 4 minimum-take obligations are too high.

The second set of scenarios (Scenarios 5-8) assume a higher capacity of renewables in Thailand. These assume that 6 GW of wind and 19 GW of solar are on the grid by 2030, the same capacity as the high renewables scenarios in the chapter "Technical flexibility". While we ran all four scenarios corresponding to Scenarios 1 to 4 above, we discuss here only Scenario 7, which corresponds to Scenario 3 above – high renewables production and peak demand. The reason for this is that Scenario 3 showed no need for downward flexibility since the increased demand absorbed the high renewables production.

Figure 3.11 Scenario 7: Extra-high renewables and peak demand



Source: EGAT.

In the augmented renewables scenario, downwards flexibility will be critical.

Figure 3.11 shows that even with peak demand the minimum-take obligations are too high when enhanced renewable capacity is producing at high levels. Scenarios 5, 6 and 8 show the same picture. In the off-peak Scenarios 6 and 8, demand could be met entirely by renewables and hydro in 2030, which creates the need for a highly flexible market structure that ensures that fossil fuel generation can be ramped down in hours of high renewables production and low demand. This means that in an accelerated renewables deployment case, compared to the 2018 PDP, it is even more important to ensure downward flexibility by adjusting minimum-take obligations.

Enhancing commercial flexibility

As shown in the analysis above, the excessively high minimum-take obligations in existing PPAs cause an issue for upcoming renewables generation. This is especially true for the off-peak. Another factor that has become evident during the Covid-19 crisis is that it is not certain that demand will always grow at the projected speed, and may even have periods of significant reduction.

If the effects of the Covid-19 pandemic were reflected in the scenarios above, it would significantly strengthen the case for improving downward flexibility. This is because the Covid-19 pandemic is characterised by even lower demand than the scenarios presented. In order to achieve downward flexibility, EGAT should take certain considerations into account.

In 2025 all currently existing contracts for hydro generation will still be active, accounting for 93% of the projected total hydro capacity. It is likely to be necessary to restructure these contracts to introduce a storage capability condition. We recommend that the restructured contracts guarantee a minimum capacity of storage. The viability of this storage scheme will depend on the hydro generators' reservoir capacity and the capability to absorb surplus power. The restructuring procedure will depend on the type of contract (EGAT or imports). Restructuring EGAT's own operation implies an easier process; however, a discussion with, for example Lao PDR, could also be attempted in light of the multilateral power trade initiative between all the ASEAN member states.

With multilateral power trade, EGAT can establish more flexible market solutions, such that Thailand can import more hydro on the days when domestic renewable generation is low, and less on the days when it is high. In this sense, the countries within ASEAN with reservoir hydro can act as a battery for the countries that do not have this resource. This is one of the critical success factors behind the integration of renewables in the northern European market. In this market Norway has the hydro storage while Denmark, for example, has high levels of wind generation capacity. On windy days Denmark exports power to Norway, while on low wind days the flow is reversed.

ASEAN has a major programme of work devoted to developing multilateral power trade, which encompasses both building physical infrastructure and creating institutions that allow for efficient utilisation of the physical infrastructure. The programme is under the ASEAN Plan for Action on Energy Cooperation (APAEC) Phase 2, 2021 to 2025. In 2019 the IEA published a study outlining the minimum requirements and tangible steps forward for ASEAN to create multilateral power trade in the region. Multilateral power trade is a crucial option for the ASEAN region more widely to integrate larger shares of renewables, and Thailand is no exception. As such, investing in multilateral power trade as a way to increase the flexibility of hydro imports is an important step for Thailand.

British Columbia and Alberta (provinces of Canada) are another example of creating flexibility by using existing hydro storage, which by 2060 is expected to provide 79% of the provinces' ramping requirement and 41% of their flexibility requirement. For fossil fuel generation assets, the need for flexibility applies both to generation owned by EGAT and by IPPs. The requirements for flexibility should not differ between them; the process should be transparent and neutral to ensure the most efficient addition of flexibility to the Thai system.

One possible obstacle to increasing power plant flexibility is the fact that Thailand currently lacks a mechanism to reward flexibility. One way to develop such a mechanism would be to restructure the national power market and introduce a competitive wholesale market for generation. In a competitive market, generators would be incentivised by variations in price to shift their production to times when the system's needs are greater. The higher prices received during these times would provide an incentive for investment in additional flexibility, as and when it is needed. An example is European coal-fired power plants.[3] The power plants have shifted generation to reflect system needs without a special programme to facilitate it. The reason a shift has happened is due to price signals from the short-term markets, such as the day-ahead market and the intraday market, and/or balancing markets.

In practice, several mechanisms are likely to be needed in a restructured market. The day-ahead market provides a short-term signal up to 36 hours ahead of operation. On days when the expected amounts of solar PV generation are high, for example, fossil fuel generators would receive a signal ahead of actual operations indicating a need to turn down their production.

An intraday or balancing market, in contrast, provides a very short-term flexibility signal. For example, in a situation where solar PV produces less generation than expected, flexible power plants would be rewarded for being able to provide additional last-minute balancing capabilities.

The approach taken in the 2018 PDP, which divides the Thai system into regions, also harmonises well with the introduction of restructured markets. Each region could be set up as a separate wholesale price zone, meaning that the regions would have different prices depending on the consumption and production patterns in the respective regions, and the available transmission capacity between them. This would provide an additional price signal to investors. If one region has a price that is persistently higher than another, investors would be incentivised to develop generation there.

Conversely, if transmission capacity between the regions is sufficient such that there is no congestion, prices among the regions should be equal. In this case,

[3] This is especially the case in markets where renewables penetration is high, such as Denmark and Germany.

investment decisions would be determined by other factors such as grid connection costs, the cost of land and resource availability.

In either case, price signals and overall investment costs would ensure that generation would be built in the most economically efficient region. Additionally, if designed well these price signals could provide incentives for the system-friendly deployment of renewables.

Regional pricing also gives the system operator a signal of the value of the transmission grid. If the price difference between two regions is consistently high, then the value of building additional transmission capacity between those two regions is also high.

In the absence of a restructured market, it would be possible to create a “semi-market” within EGAT. To create this the PPAs would have to stipulate that each generator should provide its marginal cost of production to EGAT, as well as any conditions that affect dispatch. This way EGAT would have a better overview of what conditions affect optimal dispatch, and could start to eliminate those to make the system more efficient. The marginal cost of production should be updated at certain intervals, which could be yearly or with higher frequencies. EGAT could then be allowed to dispatch according to a merit order based on the marginal cost of production. Since the marginal cost for variable renewables is zero or close to zero, renewables would tend to be dispatched first.

EGAT would also need to take into account technical restrictions, such as minimum generation levels, ramp rates and start-up times, so that these can be respected during dispatch (discussed in the technical section). This may require the relaxation of current contractual limitations related to these technical issues. In other systems where marginal prices are reported, the regulator typically monitors prices to ensure that they reflect the true cost of the power plant in question.

Providing EGAT with access to marginal prices and the ability to use them in dispatch would allow for a least-cost dispatch, which would be more efficient for the Thai system and may reduce the operational costs quite significantly (as shown in the technical section). However, it would require a higher degree of flexibility from the dispatchable plants. In Canada, examples of contract structures are found that allow for a higher degree of dispatchability. Implementing this type of contract structure would help to ensure that Thailand does not lock in excessive minimum-take obligations in the future. It is important for Thailand to ensure that contractual frameworks are not an obstacle to the government’s ambitions for integrating VRE, noting that with the current contracts in place they will be.

Consequently, contracts with generators would need to be restructured to allow for an internal market within EGAT. This is no easy task and would need to be done with extreme care to ensure a healthy investment environment. One way to restructure contracts is to apply the auction principle to the restructuring, for example holding an auction for lowering minimum guaranteed production levels. In this case the plants that are willing to run by the new terms at the lowest cost would be selected for restructuring; this way it would be voluntary and based on competitive bidding to allow generators to provide the flexibility that the Thai system needs.

Curtailment of VRE for flexibility

One of the recommendations of the Thailand Renewable Grid Integration Assessment was to establish a renewables control centre. This would assist system operations through the collection of data from renewable generators, allowing for the development of sophisticated renewable production forecasts and, if necessary, the curtailment of renewable production.

Under the current Thai PPA structures, non-dispatchable renewables are normally categorised as non-firm PPAs and are typically SPPs. This means that, at present, EGAT must purchase the non-firm energy whenever the SPPs deliver power. Under these PPAs it might be difficult for EGAT to curtail VRE production.

With high penetration of renewables, curtailment can be a necessity to protect the grid, as indicated in the technical section in the case of accelerated VRE targets in 2030. It can also be more effective from an environmental and economic perspective to curtail renewables for a short while compared to ramping thermal generation. As such, PPAs need to allow for curtailment. It is important to note, however, that renewables curtailment should only be used as a last resort, and it should only be a short- to medium-term solution. In a situation with very high shares of VRE a certain level of curtailment is acceptable to have a cost-efficient system; however, it is still important to have very clear rules and regulations around curtailment.

Renewables should, as a main principle, not be curtailed to accommodate generation from other sources such as co-generation or thermal plants. It is not economically efficient to curtail solar PV or wind to make room for generation from coal or gas, assuming the thermal plants are not at minimum load, as it will generally have a higher marginal cost (because of the cost of fuel, for example). In addition, the environmental impact of coal and gas generation should also be considered.

Even with economic efficiency and environmental considerations, it may at times be necessary to curtail renewables – for example to avoid very high ramp rates or for balancing. PPAs will need to accommodate this option. At the same time, in order to ensure that the curtailment of VRE is only used as a last resort, a suitable compensation mechanism for curtailment is required. In Germany, for example, when VRE is curtailed to maintain grid stability the VRE owner is entitled to compensation from the grid owner. This was incorporated only at a later point, due to significant difficulties in integrating VRE. It is, however, recommended to incorporate this option at an early stage in order to avoid the need to amend regulations, and especially the need for regulations that have retroactive effects.

A similar scheme for VRE in Thailand could make sense. This type of mechanism would incentivise EGAT to only curtail as a last resort, and over the long term incentivise a buildout of the grid to ensure that the Thai grid can accommodate the added share of VRE on the grid. Additionally, EGAT's visibility of distributed VRE is important in order to practically implement these measures. Since distributed PV is expected to be significant in Thailand, grid codes that require data to be shared with EGAT are essential to achieve the desired levels of flexibility.

The role of fuel supply contracts in commercial flexibility

Within the Thai power system 48% of the contracted generation in 2020 was gas-fired (Figure 3.2) and 61% of the generation owned by EGAT is gas-fired (Figure 3.3). CCGT is a very flexible technology with relatively fast ramp rates, and due to this, it is important to explore commercial constraints that may be affecting this type of generation.

CCGT power plants have underlying fuel supply contracts, which can contribute to commercial inflexibility if they contain onerous take-or-pay obligations.

Currently most domestic gas demand is met by national production and pipeline imports from neighbouring Myanmar, together with LNG imports. The Thai government is planning to increase imports of LNG as early as 2024, as domestic gas production is set to decrease, and the gas supply from Myanmar would not be enough to support domestic power demand. While the gas market is structured such that the state gas company PTT is the only provider in Thailand, the government has implemented regulations granting third-party access to the domestic gas transmission infrastructure, including LNG receiving terminals, to prepare for the increase in imports of LNG. This allows EGAT to import LNG.

EGAT has acquired access to the country's first and only LNG receiving terminal, owned and operated by PTT. EGAT has a shipping licence to import LNG under

Thailand's third-party access regime to supply its own power plants. The imports equate to 1.5 mtpa – or 2 bcm – of LNG for a 38-year period. As for the domestic gas supply, EGAT has a 10-year gas purchase contract with PTT, which is reviewed after 5 years. In the contract a daily contract quantity is set for both the supplier and the purchaser. EGAT has minimum take-or-pay obligations for the daily contract quantity, and PTT has an obligation to supply 115% of the daily contract quantity as and when requested from EGAT. The daily take obligation for EGAT can mean disruption to the merit order of electricity production, as illustrated in the previous chapter on technical flexibility. For example, on a sunny day the amount of electricity EGAT requires from dispatchable plants may be significantly lower than on a cloudy day, as shown in the previous analysis. This may mean that the daily contract quantity is higher than needed, but because of the daily obligatory take constraint some gas fired turbines may be used to generate electricity instead of other sources that would have been less expensive.[4]

Take-or-pay contracts are commonly used in other markets as well. Typically, however, they have longer observation periods, with quarterly or annual observation periods commonly used, as well as the opportunity to roll over the take-or-pay amount to the next contractual period. In the Thai system the daily obligatory take amount places much of the risk of the gas usage on EGAT, the take-or-pay obligations are financially settled each year, and some deductions of daily take-or-pay obligations can happen depending on conditions that are unclear to the writers of this report.

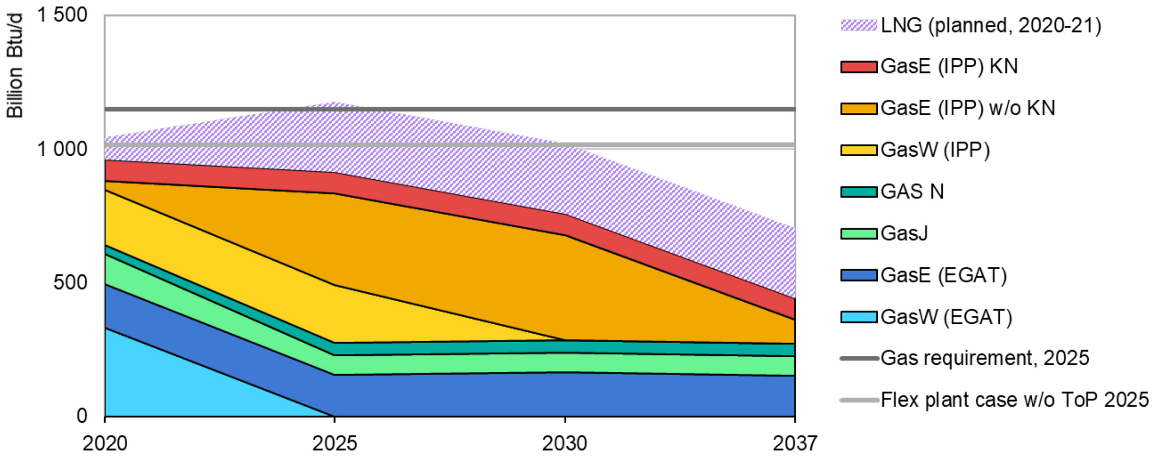
These obligations and arrangements reduce flexibility, which may be inappropriate in a system with higher shares of VRE. In such a system, EGAT would not be able to control its daily gas requirements, as they would be heavily dependent on the weather. Therefore, it might be more appropriate to place this risk with PTT, for example by moving to longer observational periods for the take obligation. This would mean that EGAT would be charged a higher margin, since the product that they buy has lower risk. This margin would compensate PTT for taking on the risk. PTT, in turn, could mitigate this risk by managing the upstream contracts.

Figure 3.12 shows a conceptual study of future contractual constraints, assuming a case where gas-fired plants exercise maximum flexibility in electricity generation. Such case could be, for example, a large demand drop due to natural disasters, a large installation of VRE capacity, or another major disruption to the energy system. Figure 3.12 shows that if power generation is reduced, the current

[4] Data on the Thai gas system are based on several articles and sources: https://www.reuters.com/article/thailand-lng-imports/update-2-thailands-egat-seeks-lng-for-first-time-as-market-liberalises-idUSL3N1VC2SM; https://clubofmozambique.com/news/thai-ptt-concludes-mozambique-lng-deal-2-6-million-tonnes-a-year/.

natural gas procurement contract may be in conflict with the demand for fuel, and an oversupply situation is created. In an oversupply situation EGAT would be required to compensate suppliers for not taking the contractual volumes on a daily basis, or meeting the “minimum daily take-or-pay volume” condition.

Figure 3.12 Potential for oversupply of gas



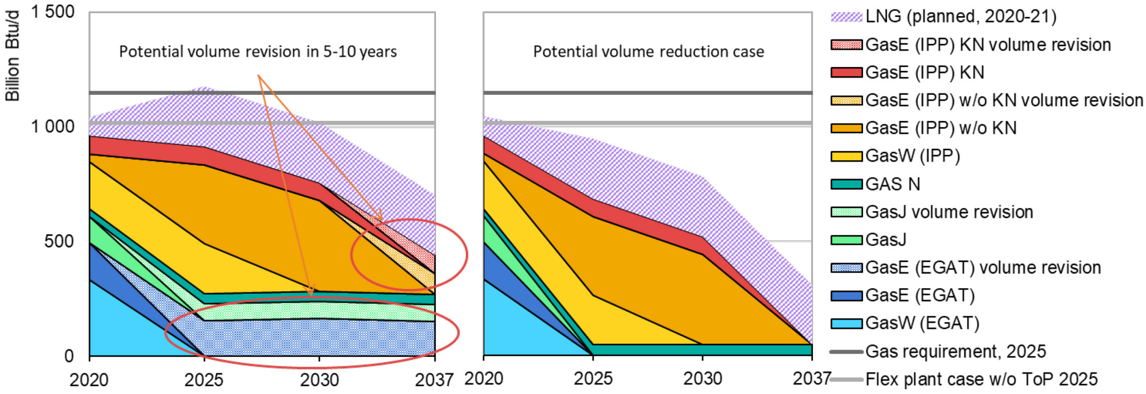
Notes: The figure is conceptual given the lack of access to procurement data for gas; data between 2025, 2030 and 2037 have been created with linear interpolation; the names in the legend reflect the contract names used by EGAT; ToP = take or pay.

Take-or-pay conditions can constrain the flexibility available in the operation of gas-fired power plants.

One option is to reduce the minimum daily take-or-pay contractual volume. This could be done at the next contract review (Figure 3.13). Reducing minimum take-or-pay obligations requires the acceptance of both seller and buyer, and a commercial negotiation would be needed to achieve this result. Figure 3.13 shows the case where the maximum reduction of daily take-or-pay obligation will balance the gas supply and a maximum generation reduction case in 2025. This case assumes that the relaxation of the contractual obligation in the gas power system could start from 2030 onwards. As VRE capacity expands fairly quickly thanks to a short construction period of up to five years, the current gas contractual status would limit the flexibility of the gas-fired power plants to provide flexibility to accommodate the expanded VRE capacity. Any contractual relaxation faster than that assumed above would greatly help integrate larger shares of renewables from a commercial perspective, especially downward ramping in the off-peak.

Note that this conceptual study is based on the scenarios simulated in the “Technical flexibility” chapter, including base scenarios and flexible power plant and fuel contract scenarios in 2025.

Figure 3.13 Reduction of take-or-pay volumes



If take-or-pay reductions are implemented in fuel supply contracts, gas-fired generation can be more flexible.

Flexibility in LNG contracts

Commonly, longer-term LNG contracts have more delivery flexibility than shorter-term contracts (Table 3.3). LNG contracts typically have an offtake obligation on a monthly or yearly basis where yearly obligations can span multiple years. For example, where the buyer does not meet its annual obligation to take a volume of LNG cargoes (take-or-pay clause), it may compensate in the following contract year(s) by taking additional cargo(es) instead. Changes to the shipping delivery schedule are arranged without extra fees.[5]

In contrast, short-term (up to five years) and spot sales have greater rigidity, as the seller and buyer have limited time to compensate for failure to meet contractual obligations. Therefore, flexibility is commonly limited. A mix of long- and short-term contracts in a portfolio strategy would assist EGAT's efforts to achieve greater flexibility.

Table 3.3 below shows possible areas of negotiation that are commonly used in LNG contracts to obtain flexibility. EGAT can explore these areas when negotiating LNG contracts to meet its need for flexibility in LNG cargo deliveries.

[5] One example of a common fee is "demurrage", a penalty for exceeding the time allowed for accepting delivery of a cargo.

Table 3.3 Areas of flexibility in LNG sale and purchase agreements

Subject	Area covered	Potential flexibility
Term	Effective time that the agreement is to be in force	• Start date in multiple windows • Early termination option • Extension option
Quantity	LNG volume to be delivered	• Volume in MBtu or by cargoes • Upward or downward quantity adjustments within a contract year/term • Early/late nomination of volume • Ramp-up/ramp-down of delivery volume
Delivery	Delivery or receiving of LNG at agreed title and risk transfer point	• Nomination of delivery terminal(s) • Optional delivery terminals • Territorial water delivery
Transport	Responsibility for cost and risk of LNG transport	• Seller's or buyer's responsibility to transport (DAP* or FOB**)
Delivery programme	Schedule for the delivery of LNG during the contract	• Nomination of delivery timing(s) • Modification of delivery timings at no cost • Delivery rescheduling rights at no cost

* DAP = delivered at place. Incoterms replaced former delivered ex-ship (DES) with DAP in Incoterms 2010. DES was used when the seller owned the vessel. Under both DES and DAP, the seller delivers when the goods are placed at the disposal of the buyer on the arriving means of transport ready for unloading at the named place of destination. The seller bears all risks involved in bringing the goods to the named place.

** FOB = free on board, a definition by Incoterms or a rule developed by the International Chamber of Commerce to clarify the terms of commercial negotiations, means that the seller delivers the goods on board the vessel nominated by the buyer at the named port of shipment or procures the goods already so delivered. The risk of loss of or damage to the goods passes when the goods are on board the vessel, and the buyer bears all costs from that moment onwards.

Options to increase flexibility in gas procurement

An additional instrument to increase flexibility in gas procurement is the use of options. They allow the buyer to request additional cargoes or reduce cargoes at short notice. Example include:

Volume tranche option – A buyer has multiple layers of contracted volume, so-called "tranches".

The buyer has an option to take several tranches of volume at agreed times. For example, an agreed total volume of 3 mtpa is sold in tranches of 2.0 mtpa, 0.5 mtpa and 0.5 mtpa. The tonnages are delivered to the buyer with different commencement dates; for example 2 mtpa in the first year, and the following volumes to be delivered in the subsequent months or years. This delivery profile is suited to a buyer who needs more visibility of the large demand increment (or, vice versa, the decrease). This example could correspond with a process of switching energy from gas to LNG where the tranche volumes accommodate forthcoming LNG demand increases.

Put option – A buyer has the right to sell ("put") a cargo to a third party at very short notice.

For Asian LNG buyers this option is useful where the buyer has an unwanted cargo that it has not been able to consume as originally planned. The cargo destination is usually pre-agreed, the nominated receiving terminals typically having low utilisation rate. These receiving terminals have the physical capacity to take the unwanted cargo throughout the year, hence having higher availability.

Call option – A buyer has a right to ask for ("call") an agreed cargo from a seller at short notice and the seller is obligated to meet the request. The option is useful in the case of sudden demand surge. A call option contract serves as a firm extra spot cargo for the buyer.

Options are typically sophisticated financial instruments and do come at a cost. However, they may be a good tool to use at times where gas demand is particularly difficult to predict since they allow for a high degree of flexibility at relatively short notice.

Recommendations to increase contractual flexibility in the Thai system

Our analysis demonstrates the need to increase contractual flexibility so that the Thai power system can integrate higher shares of renewable energy. The need to increase flexibility relates to minimum-take obligations in physical PPAs as well as fuel supply contracts.

We therefore propose the following recommendations to increase flexibility in the Thai system:

- Continue engaging in the development of multilateral power trade in ASEAN, with the goal of achieving more flexible conditions for hydro imports.
- Consider separate negotiation of more flexible terms for hydro imports.
- Assess the need to renegotiate firm contracts with the aim of minimising EGAT's minimum-take obligations.
- Consider developing an auction mechanism for the renegotiation of firm contracts.
- Insist that new contracts have lower minimum-take obligations, if any, taking into account technical restrictions.

- Implement clear rules for VRE curtailment in PPAs.
- Increase flexibility in fuel supply contracts by investigating renegotiation of take-or-pay volumes.
- Develop a portfolio procurement strategy for fuel supply by mixing long- and short-term products to optimise the flexibility of gas fuel supply.

Conclusions

In this study we examine several levels of VRE deployment and the effects they could have on the flexibility needs of Thailand. We analyse flexibility from both the technical and commercial angle using the current context of Thailand's power system. Both angles are important for a system to be able to use the full range of flexibility options that are available in the most cost-effective and secure way possible. It is important that the necessary technical solutions are in place. These could consist of a mix of measures at conventional power plants and on the electricity network, plus storage and distributed energy resources (including demand response). In order for system operators to effectively use this hardware, contractual structures must allow for different types of generation patterns. This includes relaxing minimum-take obligations and applying a portfolio approach to purchasing fuel.

This study finds that investing in hardware options may not be a priority in the current context of Thailand's power system due to the modest economic benefits compared to the cost of investment. The greatest cost saving would come from relaxing the constraints on the supply of fuel and in power purchase contracts, as this would lead to the efficient use of system assets in general.

Technical flexibility

- As the share of VRE on the system increases, so the Thai power system's need for flexibility will grow (reflected in ramping requirements and the gap between daily net minimum and peak demand). Operational practices and planning approaches should take into consideration these rising flexibility requirements.
- Thailand's current and future power system has significant latent technical flexibility to integrate up to a 15% share of VRE by 2030, but barriers surrounding power and fuel procurement often prevent that flexibility from being accessed, leading to higher system costs.
- Instead of retrofitting power plants, where the retrofit costs far outweigh the savings, changes in certain plant operational procedures (particularly for IPPs) should be considered to unlock power plant flexibility. The focus should be on lowering the MSL since it is the most constrained dimension from the technical standpoint.

- Under the current context of Thailand's power system, investing in plant retrofits, PSH and BESS is unlikely to be a top priority in the short to medium term.
- Unless fuel contracts and PPAs are renegotiated to allow more cost-effective operation of the power system, power plant retrofits and additional storage options to improve system flexibility will have a limited value given the modest cost savings and the high investment cost.
- As Thailand further accelerates its clean energy transition, the country could consider a combination of power plant flexibility and storage options to accommodate higher ambitions for renewable energy deployment.

Contractual flexibility

- Minimum-take requirements in PPAs should be reduced so they are more in line with the needs of the system – especially during off-peak periods.
- Hydropower has potential to provide additional flexibility in the future.
- The take-or-pay requirements in fuel supply contracts are a blocking factor for optimal contract flexibility.
- The Thai power system needs a new contractual framework where generators' contribution to system flexibility is rewarded
- Thailand should continue engaging in the development of multilateral power trade in ASEAN, with the goal of achieving more flexible conditions for hydro imports.
- The country should consider negotiating separately for more flexible terms for hydro imports.
- EGAT should assess the need to renegotiate firm contracts with the aim of minimising minimum-take obligations.
- It should consider developing an auction mechanism to renegotiate these firm contracts.
- New contracts must have lower minimum-take obligations, if any.
- EGAT should implement clear rules for VRE curtailment in PPAs.
- The degree of flexibility in fuel supply contracts should be increased by investigating the potential to renegotiate take-or-pay volumes.
- A portfolio procurement strategy for fuel supply is needed, mixing long- and short-term products to optimise the flexibility of gas fuel supply.

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Acronyms and abbreviations

ASEAN	Association of Southeast Asian Nations
CCGT	combined cycle gas turbine
CDM	Clean Development Mechanism
EGAT	Electricity Generating Authority of Thailand
EPPO	Energy Policy and Planning Office
ETS	emission trading scheme
EU	European Union
GHG	greenhouse gas
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
LCOE	levelised cost of energy
LT-LEDS	Long-Term Low Greenhouse Gas Emission Development Strategy
MEA	Metropolitan Electricity Authority
MRV	measurement, reporting and verification
NAMA	Nationally Appropriate Mitigation Actions
NDC	Nationally Determined Contribution
O&M	operations and maintenance
ONEP	Office of Natural Resources and Environmental Policy and Planning
PDP	Power Development Plan
PEA	Provincial Electricity Authority
PPA	power purchase agreement
SPP	small power producer
TGO	Thailand Greenhouse Gas Organisation
T-COP	Thailand Carbon Offsetting Program
THB	Thai Bhat
T-VER	Thailand Voluntary Emission Reduction scheme
UNFCCC	United Nations Framework Convention on Climate Change
USD	United States dollar
V-ETS	Thailand Voluntary Emission Trading Scheme
VRE	variable renewable energy
VSPP	very small power producers
WEO	World Energy Outlook

Units of measure

CO_2	carbon dioxide
t CO_2	tonne of carbon dioxide
t CO_2/MWh	tonne of carbon dioxide per megawatt hour
GJ	gigajoule
GW	gigawatt
kg CO_2	kilogram of carbon dioxide
kWh	kilowatt hour
Mt CO_2	million tonnes carbon dioxide
MW	megawatt
MWh	megawatt hour
TWh	terawatt hour

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