

Energy Without Borders:

The Architecture of Power Connectivity in Central Asia



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ENERGY WITHOUT BORDERS

The Architecture of Power Connectivity in Central Asia

KEY TAKEAWAYS

ANALYTICAL REPORT '26

POTENTIAL IMPACT OF A DEVELOPED ARCHITECTURE



Up to **640**
USD million/year
gross effect



Up to **120**
USD million/year
net effect



2.8–4.5
billion kWh/year
lower RES curtailment

4 BENEFIT CHANNELS

Trade arbitrage

Shared reserves

Less RES curtailment

Lower emergency costs

CHALLENGES

Why existing interconnection is not fully used



GRID AT ITS LIMIT

102–123%

overloads on key lines at the 2024 peak

GRID



CAPACITY ≠ AVAILABILITY

6.6 GW

unavailable/restricted + 0.85 GW under repair

AVAILABILITY



RES OUTPACE THE SYSTEM

3.5 billion kWh

RE curtailment in Uzbekistan in 2028

FLEXIBILITY



POORLY CONTROLLABLE GRID

Outages 2022–2026

cascading trips ·
manual coordination · conservative limits

CONTROLLABILITY

ROOT CAUSES

Five structural constraints explain the four system-level challenges



GRID
BOTTLENECKS

- Both within countries and at interfaces
- Physical link ≠ available transfer capacity



GENERATION
AVAILABILITY

- 6.6 GW was unavailable at the 2024 peak for various reasons



FLEXIBILITY
& RESERVES

- Limited maneuverability of existing generation
- Shortage of fast-acting reserves and storage
- Limited joint use of reserves



OBSERVABILITY
& AUTOMATION

- Incomplete picture of grid state
- Fragmented data and models
- Manual coordination



INSTITUTIONS
& RULES

- Differing rules and areas of responsibility
- Immature balancing and ancillary services mechanisms
- Allocation of benefits and costs

SOLUTIONS

Three dimensions of integration



PHYSICAL

- Strengthening internal corridors and cross-border interfaces
- Development of BESS and flexible capacity
- Substations, transformers + reactive power compensation



TECHNOLOGICAL /
DIGITAL

- Unified digital loop: SCADA/EMS · AGC · WAMS/WACS · AMI · verified models
- Secure data exchange + settlement infrastructure
- Automatic control + emergency control
- RES and load forecasting + ATC/NTC calculation



INSTITUTIONAL

- Allocation of powers and functions among system operators, national regulators, CDC and market participants
- Launch of pilot markets: day-ahead, balancing, ancillary services
- Hydro-flexibility payment mechanism + allocation of benefits and costs

National dispatch control is retained; regional functions develop as integration matures.

PHYSICAL CONNECTIVITY + CONTROLLABILITY = REGIONAL SYSTEM EFFECT



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Full version of
the analytical
report



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Central Asia is not starting its energy integration from scratch: the region has inherited a well-developed grid interconnection, seasonal water-energy exchanges, and complementary resources. However, the previous architecture was designed for a different reality—current conditions require greater controllability of the power system. This report examines regional electricity cooperation and integration as a practical mechanism for a “Middle Path” strategy—that is, a balance between reliability, energy affordability, and environmental sustainability. The key argument is that the future value of an interconnected system will be determined not only by the scale of the infrastructure, but above all by the level of controllability, transparency, and the ability to ensure reliable regional coordination.

Experience from developed markets shows that the benefits of integration stem not only from electricity trade, but also from lower reserve costs, an expanded balancing zone, higher asset utilization, and lower curtailment of renewable energy. The report provides an analysis of the current situation and challenges, as well as a phased roadmap for increasing cross-border trade: from observability, metering, deviation rules, emergency support, and balancing energy exchange to short-term trading, balancing, the ancillary services market, and regional instruments for ensuring long-term resource adequacy. This phased approach will enhance the reliability of the Central Asia Power System, reduce the total cost of reliability, alleviate curtailment of RE, unlock the investment value of grid and digital projects, and prepare the region for sustainable participation in external power markets.

Keywords: Central Asia, Central Asia Power System (CAPS), “Middle Path,” energy trilemma, power sector, RE, energy transition, electricity trade, sustainable development, regional interconnectivity.

JEL: Q40, Q42, Q48, L94, F15, O13, R42.

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SUMMARY

Central Asia already has a substantial degree of physical power-system interconnection, inherited from the Soviet-era grid. Its economic and system-wide value today is constrained less by nominal generating capacity than by operational controllability: data quality, settlement metering, secure information exchange, automatic controls, and clear rules for coordination and settlement. The central challenge is therefore to turn inherited physical interconnection into a transparent and manageable regional architecture.

Assessment of the Joint Power System

The Central Asia Power System (CAPS) is the regional synchronous power system linking Uzbekistan, Kyrgyzstan, Tajikistan, and southern Kazakhstan, while selected generating units in Turkmenistan and northeastern Afghanistan are connected through islanded configurations. As of January 1, 2025, installed capacity within the CAPS technical perimeter was 38.6 GW; in 2024, generation totaled 125.4 billion kWh and consumption 142.2 billion kWh. Regional trade recovered from 2.5 billion kWh in 2010 to 12.1 billion kWh in 2024, but remains below its 1990 level relative to consumption (about 8.5% versus 13%) and about half the EU level, because of grid constraints, reserve availability, and incomplete formalization of commercial arrangements.

The report's central diagnostic finding is that the region's central constraint is not installed capacity, but the availability, flexibility, and deliverability of capacity in critical hours. Fuel and hydrological constraints, offline thermal units, and grid bottlenecks mean that part of the nameplate capacity is unavailable precisely when the system needs it most. Regional cooperation therefore creates value only where resources are demonstrably available and deliverable, rather than merely present on paper.

The region's power systems contribute complementary resources to a common reliability portfolio. Uzbekistan is the largest center of demand, generation, and renewable integration; southern Kazakhstan is a major load center exposed to North–South transit constraints; Kyrgyzstan and Tajikistan provide hydropower flexibility and seasonal balancing; Turkmenistan can supply surplus gas-fired capacity under suitable interconnection arrangements; and Afghanistan remains a potential southern offtake and transit market.

Renewables Increase the Cost of Poor Coordination

Countries across the region are rapidly expanding solar and wind generation. In Uzbekistan, renewable capacity could reach 25 GW by 2030 under announced plans. At the same time, curtailment of renewable energy (RE) is projected to rise from about 2.2 billion kWh in 2026 to 3.5 billion kWh in 2028 under conservative assumptions. Curtailment reduces usable generation, while payment obligations to generators may remain, depending on PPA terms, leaving the associated costs with the offtaker, system operator, or ultimately consumers. Regional interconnections, access to hydropower flexibility, storage, and stronger market signals can materially reduce this burden.

Economic Benefits of Integration

The economic rationale for integration lies in reducing the total cost of reliable electricity supply through four channels: trade arbitrage, reserve sharing, lower curtailment of RE, and lower emergency costs. A preliminary scenario-based assessment indicates a net system-wide effect of about USD 120 million per year under both the partial and deeper integration scenarios and about USD 40 million per year under the advanced regional architecture in the central case (midpoint). These are annual values, not cumulative or lifetime amounts. Under unfavorable conditions, such as low utilization combined with high infrastructure costs, the net effect may be negative, particularly for the advanced regional architecture. The results point to diminishing marginal returns as integration deepens: partial integration captures relatively low-cost gains from improved use of existing infrastructure and coordination, while subsequent stages require progressively larger grid and institutional investments. This supports a phased approach in which deeper integration is pursued as earlier stages demonstrate sufficient utilization, system benefits, and institutional readiness. The estimates are screening-level indications of the order of magnitude of the potential effect rather than forecasts; outcomes may be materially higher or lower depending on infrastructure costs, utilization, and the effectiveness of regional coordination.

Regional benefits will not be distributed evenly. One country may benefit from lower curtailment of RE, another from transit revenues, a third from remuneration for hydropower flexibility, and a fourth from lower shortage or emergency-support costs. A project that is economically attractive for the region as a whole can therefore remain politically difficult unless benefit-sharing and cost-allocation mechanisms are defined in advance.

Hydropower as a Remunerated Resource for System Flexibility

Hydropower in Kyrgyzstan and Tajikistan, including Toktogul, the Naryn Cascade, Nurek, and the prospective Rogun HPP, provides peak support, balancing, reserves, and seasonal flexibility to the region. Water is a multipurpose resource linked to irrigation, food security, and interstate water obligations. Hydropower flexibility should therefore be treated as a measurable and remunerated ancillary service, not as a free reserve available to downstream systems by virtue of geography. A credible regional model must explicitly compensate this flexibility, while respecting water-management obligations.

A Phased Market Architecture, Not a Supranational Regulator

The report proposes building the market architecture in phases, on top of existing mechanisms, rather than through the immediate creation of a supranational market.

- The first level consists of bilateral transactions, coordinated dispatch schedules, settlement metering, rules for settling deviations, and emergency mutual assistance.
- The second level consists of a limited “day-ahead” market with confirmed available transmission capacity.

- The third level introduces real-time balancing and ancillary services, including frequency response, operating reserves, voltage and reactive-power support, and emergency assistance.
- The fourth level establishes regional resource adequacy assessment and rules for recognizing dependable cross-border resource contributions.

National system operators retain full control over domestic system operation at every stage. As transparency and settlement reliability improve, CDC Energia could assume selected functions as regional coordinator, market-platform operator, and settlement coordinator. Market-power monitoring and dispute resolution, however, should remain organizationally separate from these functions. This separation is a prerequisite for participant confidence, not a technical design detail.

Investment priorities, including grid projects (Shymkent–Tashkent TPP, Muruntau–Shymkent, Kemin–Almaty, Frunze–Kemin, Kristall–Yulduz, Datka–Sughd) and digital infrastructure (the AGC Coordination Center, wide-area monitoring, secure communications), should be assessed against measurable system-wide outcomes: higher available transfer capacity, lower congestion and curtailment of RE, and improved reliability.

External Corridors: Five Routes with Varying Levels of Maturity and Risk Profiles

External corridors should be treated as a portfolio of options whose value increases as the internal controllability of the CAPS improves. Each route has a different combination of technical maturity, commercial opportunity, and external risk.

- The Northern Vector (Kazakhstan–Russia/EAEU) is the most mature external reliability link. Kazakhstan’s North–South corridor, with a transfer limit of about 2.1 GW in the operating conditions considered, already supports balancing and, as demonstrated in 2022, emergency assistance. Its value depends on the reliability of Kazakhstan’s internal transmission network and on external regulatory conditions.
- The Southern Corridor (CASA-1000) provides a route for seasonal hydropower exports to South Asia. Its sustainable utilization depends on residual summer export availability, the Datka–Sughd and Afghan sections, water conditions, and the political and institutional environment in Afghanistan.
- The Eastern Route (China) offers access to a potentially large market, but requires a confirmed creditworthy offtaker, an agreed technical configuration, and a bankable long-term contractual model.
- The Trans-Caspian Green Corridor offers a long-term option for certified green electricity exports to Europe, but remains at an early feasibility-study stage.
- The Turkmenistan–Iran route depends primarily on the synchronization architecture and the possible use of a controllable HVDC interconnection.

No external corridor is free from factors outside the region’s control. Planning for reserves, firm imports, and export commitments should therefore explicitly reflect route-specific availability and external risk.

Market Development Roadmap

The proposed roadmap is a sequence of maturity levels, not a rigid timeline.

- In 2026–2028, priorities should include settlement metering, telemetry, secure data exchange, coordinated dispatch schedules, a transaction registry, imbalance-settlement rules, emergency-energy accounting, inter-operator balancing-energy exchange, and preparation for pilot trading. The objective is a transparent operating framework in which every delivery is metered, every transaction has a schedule and balancing responsibility, and every deviation is settled under predefined rules.
- In 2028–2030, the focus may shift to implementing priority grid upgrades, calculating NTC/ATC, expanding AGC and WAMS/WACS, updating requirements for RE sources and BESS, launching a pilot “day-ahead” market, and developing payment mechanisms for balancing energy and ancillary services.
- After 2030, once the necessary maturity is achieved, full-scale real-time balancing, regional resource adequacy assessments, recognition of cross-border contributions of reliable capacity, the development of more sophisticated cost-sharing mechanisms, and the expansion of external corridors may become possible.

Transition between stages should be governed by measurable readiness criteria: data and metering quality, resolution of discrepancies, reserve availability, growth in NTC/ATC, lower curtailment of RE, payment discipline, and institutional readiness.

Central Asia already has power lines. What is still lacking is an “architecture of trust” among countries, operators, and investors; without it, the power lines may remain nothing more than lines on a map.

This architecture rests on practical institutional and technological foundations. Settlement metering, secure data channels, and wide-area monitoring make cross-border flows visible. Imbalance-settlement rules and independent market monitoring make them predictable. Day-ahead trading and ancillary services then convert this predictability into price signals for generation, reserves, and storage. Remuneration of hydropower flexibility and transparent benefit sharing make cooperation durable rather than dependent on ad hoc goodwill.

For the Eurasian Development Bank, regional electricity cooperation creates a distinct class of cross-border investment opportunities whose benefits extend beyond a single country. The Bank can add value not only through financing, but also by translating CAPS constraints into investment-ready projects through technical diagnostics, economic appraisal, benefit- and cost-sharing mechanisms, and intergovernmental dialogue. Priority should go to projects with measurable regional benefits: higher available transfer capacity and reliability, lower curtailment of RE, and greater scope for trade and shared flexibility.

INTRODUCTION

The Eurasian Development Bank (EDB) report “Power Sector of Central Asia: Modernization and Energy Transition” introduced a “Middle Path” strategy for the region: a pragmatic balance between energy security, affordability, and environmental sustainability. This framework is particularly relevant to Central Asia, where rapid demand growth, aging assets, accelerated renewable deployment, water-energy constraints, and emerging external corridors are reshaping power-system operation ([Vinokurov et al., 2026](#)).

This report translates the “Middle Path” strategy into an operational framework for regional power-sector cooperation, with a focus on reliability, affordability, and sustainability. Central Asia already has physically interconnected power systems, but rising demand, new generation, rapid renewables deployment, and external interconnections are placing greater demands on transmission grids, reserves, and dispatch coordination.

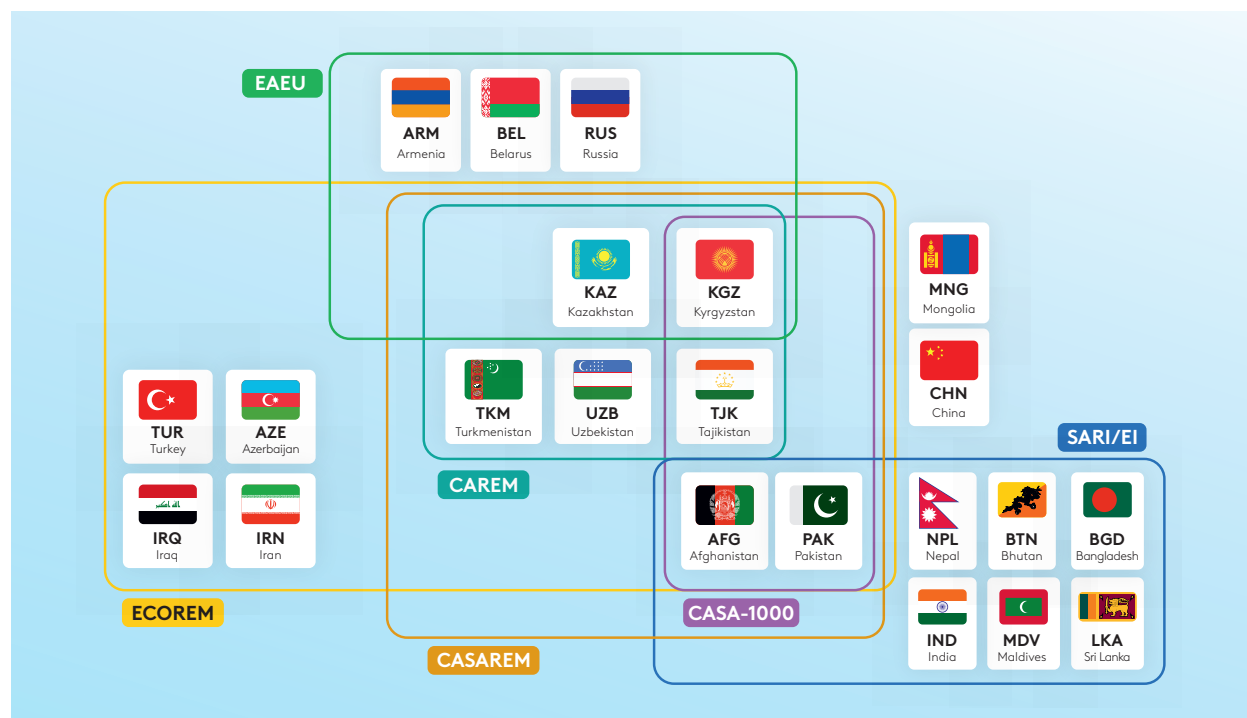
Under these conditions, the key issue is not interconnection per se, but whether power can be transferred safely between systems, coordinated operating conditions can be maintained, and settlement rules can be enforced. Grid and digital infrastructure have not kept pace with new generation, constraining electricity trade and reducing the value of new investment.

Rapid renewables deployment and new external interconnections are increasing the operational demands on the CAPS. Meeting them requires stronger interconnection infrastructure, digital observability, forecasting, operating reserves, fit-for-purpose grid-connection requirements, and harmonized commercial rules. International experience shows that durable regional integration advances simultaneously across infrastructure, system operation, market design, and institutions ([IEA, 2024](#)).

Regional cooperation is also important in the context of external energy corridors. Central Asia lies at the intersection of several vectors: the southern CASA-1000 route, the northern loop connecting Kazakhstan, Russia, and the broader Eurasian synchronous zone, the eastern route to China, the Trans-Caspian Green Energy Corridor, and the southwestern route from Turkmenistan to Iran. Each of these corridors opens up opportunities for diversifying markets, routes, sources of investment, and technological partnerships. At the same time, each of them places additional demands on the system resilience of the CAPS.

International experience shows that regional electricity integration develops through a combination of five components: interconnection infrastructure, coordinated planning and investment, technical and operational coordination, commercial mechanisms and market design, and institutional architecture ([ESMAP, 2025](#)). International approaches are used in this report as an analytical framework. Applying them to the CAPS requires consideration of the existing structure of power systems, national market models, water-energy constraints, and differences in the countries’ digital readiness.

↓ Figure 1. Initiatives to Develop Regional Electricity Markets in Central, South, and West Asia, as well as in Eurasia



Source: IEA, 2021.

Regional cooperation also has a distinct investment dimension. Many of the decisions required involve capital-intensive assets that exceed the financing capacity of individual national budgets: transmission upgrades, cross-border lines and substations, storage, digital control systems, RE forecasting, and the institutional infrastructure of a future regional market. The benefits of these investments often cross national borders: an asset financed in one country may improve reliability, transfer capability, flexibility, or investment conditions across several power systems.

This cross-border distribution of benefits complicates project appraisal and financial structuring. A substantial share of value may not appear in the direct revenue of the asset itself, but in lower emergency costs, lower curtailment of RE, reduced reserve requirements, higher trade volumes, and improved reliability in neighboring systems. For international financial institutions and private investors, project preparation should therefore identify system-wide benefits, their allocation across countries, compensation mechanisms, and credible sources of repayment. Regional cooperation creates an investment space in which projects should be assessed by both their location and their contribution to the CAPS as a whole.

The World Bank's Regional Electricity Market Interconnectivity and Trade (REMIT) program provides the main practical framework for expanding regional trade. Its implementation schedule, financing envelope, and targets for interconnection capacity and clean-energy integration represent World Bank program objectives. REMIT and the Central Asia Regional Economic Cooperation (CAREC) Program address different layers of the regional agenda: REMIT focuses on financing interconnection infrastructure, digital systems, and initial market mechanisms, while the CAREC Energy Strategy 2030 provides a broader policy framework, and ADB's CAREC Power Sector Regional Master Plan provides a least-cost planning reference for regional generation and transmission.

The distinctive contribution of this report is its narrower operational focus on the CAPS: it links actual operating constraints and internal grid bottlenecks to the total cost of reliability, the value of hydropower flexibility, the sequencing of market reforms, and criteria for investment feasibility. In this way, the report complements REMIT and CAREC with an EDB technical-economic and investment framework, including analysis of external corridors and prioritization of projects according to measurable system-wide effects ([ADB, 2019](#); [ADB, n.d.](#); [World Bank, 2026a](#); [World Bank, 2026c](#)).

The central question of this report is how to transform the existing physical interconnection of the Central Asia Power System into a managed regional architecture that ensures reliability, flexibility, trade, and investment. The answer requires a comprehensive examination of the engineering, economic, and institutional conditions governing the development of the Central Asian power sector.

The practical significance of regional integration is assessed across five interrelated areas: reliability, economic efficiency, RE integration, water-energy coordination, and investment predictability. Together, these factors determine the extent to which regional connectivity reduces the total cost of reliability, increases the utility of existing assets, and creates conditions for new investments. A detailed assessment of these areas is presented in the following chapters of the report.

An additional regional framework is ESCAP's Regional Road Map on Power System Connectivity, "Promoting Cross-Border Electricity Connectivity for Sustainable Development," endorsed by ESCAP member States in 2021 ([ESCAP, 2021](#)). The Road Map provides a non-binding framework for regional cooperation on power-system integration for 2020–2035. This report can be viewed as Central Asia's analytical contribution to its implementation, translating the broader regional framework into concrete operational, market, and investment priorities for the CAPS. The report is aligned with Road Map strategies on coordinated grid planning, policy and regulatory harmonization, development of multilateral electricity trade, coordination of cross-border grid planning and operation, investment mobilization, data sharing and capacity building, and alignment with the UN Sustainable Development Goals.

The report draws on several types of analytical material. The cutoff date for CDC Energia operational data used in the CAPS technical diagnosis was May 2025; for some indicators, the latest comparable and verified data therefore relate to 2024 and the 2024/25 winter operating period. More recent information is used where comparable official sources are available. Technical and operating indicators are based primarily on CDC Energia, national system operators, and official project sources. International examples are used for comparison rather than transferred mechanically to Central Asia. Conclusions on country system roles, investment priorities, market architecture, and external corridors represent EDB expert assessment. Quantitative integration benefits are preliminary scenario estimates intended to indicate orders of magnitude, not market forecasts or project-level appraisals.

The structure of the report follows this logic. Chapters 1–4 provide a strategic and technical assessment of the Central Asia Power System (CAPS). Chapters 5–7 examine the economics of cooperation, hydropower flexibility, and a phased market architecture. Chapters 8–10 link the findings to investment projects, external energy corridors, and an implementation roadmap.

1.

REGIONAL COOPERATION AS A PRACTICAL MECHANISM FOR THE “MIDDLE PATH” STRATEGY



The Energy Trilemma as an Analytical Framework

Central Asia's energy policy is evaluated based on three interrelated criteria: reliability, affordability, and environmental sustainability. These criteria form the basis of the energy trilemma, which the EDB uses as a core component of its "Middle Path" strategy—a pragmatic approach to the energy transition that takes into account climate goals, system stability, and the social acceptability of change (Vinokurov et al., 2026).

Box 1. The EDB's "Middle Path" Strategy

The concept of the "Middle Path" was introduced in the EDB report "Power Sector of Central Asia: Modernization and Energy Transition" (Vinokurov et al., 2026) as a response to two extreme approaches in the global debate on the energy transition: "green" maximalism, which calls for a forced phase-out of fossil fuels without regard for infrastructure readiness, and conservative skepticism, which delays modernization on the grounds of risks and costs. The report considers both approaches inapplicable to Central Asia—a region with aging infrastructure, rapidly growing demand, and limited integration of energy systems. Instead, it proposes a pragmatic path centered on the World Energy Council's energy trilemma—simultaneously achieving energy security, affordability, and environmental sustainability, without sacrificing one goal for another.

On a practical level, the report outlines the strategy through seven principles adapted to the regional context:

- balancing the trilemma's objectives—measurable, comparable indicators of reliability, affordability, and sustainability instead of a policy focused on a single axis;
- diversification and technological pluralism—rejecting the logic of a dominant resource in favor of a multi-component energy mix (renewables, natural gas, nuclear power, hydropower, and energy storage);
- rejection of radical measures—a phased retirement of obsolete capacity as replacement infrastructure becomes available, rather than based on fixed deadlines;
- proactive grid development—investments in grid infrastructure as a limiting factor in the energy transition, rather than a secondary consideration;
- system flexibility and reserves—institutional and market mechanisms that incentivize investment in system flexibility;
- affordability and tariff reform—the gradual alignment of tariffs with economically justified levels while providing targeted social protection;
- inter-system connectivity and regional cooperation—cross-border integration of power systems as a tool for reducing reserve requirements and aggregate investment costs, which requires the harmonization of market rules, the distribution of benefits, and institutional frameworks for cooperation.

This report focuses specifically on the last of these principles—regional interconnectivity—translating it from a general framework into an applied architecture for trade, reserve management, market design, and investment priorities within the Central Asia Power System (CAPS). The 2026 report also outlines the remaining six principles and provides a comprehensive analysis of the energy trilemma as it applies to the countries of the region.

Reliability refers to a power system's ability to meet demand at all times, withstand emergency outages, maintain frequency and voltage within acceptable limits, and recover quickly from disruptions. For Central Asia, this criterion is particularly sensitive to seasonal water availability, fuel constraints on gas-fired generation, the condition of the grids, the availability of reserves, and the quality of dispatch control.

Affordability means that electricity remains affordable for households and competitive for industry. In the region, this criterion is of great social importance. Low rates have long supported energy affordability, but at the same time have placed limits on investment in grids, generation, and digital systems. As assets are modernized, reserves are developed, commercial metering is implemented, and digitalization progresses, tariff policy will require more precise calibration: the sector's financial sustainability must be balanced with targeted protection for vulnerable consumers and a reduction in hidden subsidies, which undermine investment predictability.

Environmental sustainability is linked to reducing carbon intensity, integrating RE sources, modernizing thermal power plants, reducing losses, improving energy efficiency, and adapting to climate risks. For the region, it is important to consider this criterion alongside reliability. Solar and wind power reduce the carbon footprint, but require grid reinforcement, fast-response reserves, accurate forecasting, and adapted technical requirements for the connection and operation of facilities. Hydropower provides low-carbon flexibility, but its operation is tied to irrigation, low water levels, and interstate water management agreements.

Regional cooperation addresses all three aspects of the trilemma simultaneously. In terms of reliability, it provides mutual reserve capacity, emergency support, the exchange of balancing energy, and a broader dispatch area. In terms of affordability, it reduces the total cost of reliability: countries can utilize neighboring resources instead of fully duplicating reserve capacity within their national borders. In terms of sustainability, it helps integrate more RE sources and utilize hydropower as a balancing resource, while complying with water and energy conditions. Thus, cooperation yields practical benefits if it is developed in phases and with due consideration for national interests (ESMAP, 2025; IEA, 2024).

In this context, it is important to define the criteria for evaluating regional integration. The volume of kilowatt-hours remains an important metric, but it does not fully capture the value of integration. For the stability and efficiency of future power systems, often “invisible” parameters are crucial—such as available and net transmission capacity (ATC/NTC), the quality of commercial metering, the accuracy of schedules, the volume

of settled deviations, the availability of reserves, the reduction in curtailment of RE generation, the effectiveness of automation, and the system's ability to withstand peak-load hours.

Integration helps countries better implement their own energy strategies through shared infrastructure, complementary resources, and harmonized regulations. A well-designed regional architecture can strengthen national energy security while preserving sovereign management of power systems, national dispatch control, and states' responsibility for the reliability of energy supply.

Demand, Infrastructure Wear and Tear, and the Need for Joint Planning

The entire Central Asian region is experiencing a period of steady growth in electricity demand. By 2030, demand could increase by approximately 27% compared to 2026, reaching 370 billion kWh. This growth is driven by demographics, urbanization, industrialization, electrification, increased residential electricity consumption, digitalization, data centers, cryptocurrency mining, electric vehicles, and other factors (Vinokurov et al., 2026).

This growth in demand is occurring against a backdrop of significant asset depreciation. Up to 70% of the region's power grids and thermal power plants need modernization. A significant portion of the existing thermal power plants, hydropower plants, and power grids were built during the Soviet era and have long provided low-cost energy thanks to assets that have already been fully depreciated. This resource is gradually being depleted. Therefore, energy policy addresses two objectives simultaneously: meeting growing demand and upgrading the infrastructure that underpins the current availability of electricity.

Under these conditions, isolated national planning can lead to duplication of reserves, grid reinforcements, and flexible capacity. Regional coordination involves harmonizing demand forecasts, schedules for the commissioning and maintenance of generation capacity, reserve requirements, and the development of key interconnection points. This makes it possible to identify projects with cross-border system-wide benefits, reduce the risk of simultaneous shortages and overloads, and allocate limited investment resources more effectively.

RE Integration and New Requirements for System Flexibility

The development of RE sources is becoming one of the main factors driving changes in how power systems operate. The region plans to commission more than 35 GW of variable RE capacity by 2035. RE is an important part of the "Middle Path," but its sustainable growth requires development of grids, energy storage systems, flexible reserves, and digital grid management tools (Vinokurov et al., 2026; IEA, 2024). This issue has become a practical one. In Uzbekistan, if the announced projects are implemented, RE capacity could reach 11.4 GW by 2028, and battery energy storage

systems (BESS) capacity could reach 4.3 GW. At the same time, a significant volume of curtailment of RE generation is projected: 2.2 billion kWh in 2026, 3.0 billion kWh in 2027, and 3.5 billion kWh in 2028. The integration of RE sources is becoming a matter not only of installed capacity, but also of system readiness: grid accessibility, forecasting, reserves, technical requirements, and operational discipline.

Seasonal and Daily Complementarity of the Region's Power Systems

Central Asia possesses a rare combination of energy resources: thermal generation, significant hydropower potential, growing solar and wind capacity, major centers of demand, and several external trade routes. When properly coordinated, this combination reduces the cost of balancing seasonal and daily variations.

Seasonal complementarity has historically been one of the cornerstones of the CAPS. The upstream countries—Kyrgyzstan and Tajikistan—have hydropower facilities and reservoirs whose operation is tied to the irrigation needs of the downstream countries. In the summer, water releases from hydropower plants are guided by downstream irrigation requirements. During the non-vegetation season, some of the energy is returned to the upstream countries or replaced by supplies from thermal power plants. This model is changing due to rising domestic demand, diminishing water flows, and grid constraints, but its underlying logic remains important.

Complementarity also helps balance RE: the increase in solar generation creates daytime surpluses, while peak residual load often occurs in the evening hours. The combined use of hydropower plants, BESS, flexible thermal generation, and interconnections helps smooth this profile, reduce curtailment of RE, and decrease the need for backup reserves. However, the availability of hydropower flexibility depends on water availability, irrigation commitments, domestic demand, equipment condition, and grid delivery capacity.

To fully benefit from this complementarity, additional tools are required. Independent studies of the water-energy nexus in Central Asia also show that technical complementarity does not translate into sustainable cooperation without coordinated institutions, data sharing, and mechanisms for sharing benefits and risks ([Bernauer and Siegfried, 2012](#); [Sehring, 2009](#); [De Keyser et al., 2023](#); [De Keyser et al., 2026](#)). The relevant technical, economic, and market mechanisms are discussed in the following chapters of this report.

2.

TECHNICAL PROFILE OF THE CENTRAL ASIA POWER SYSTEM



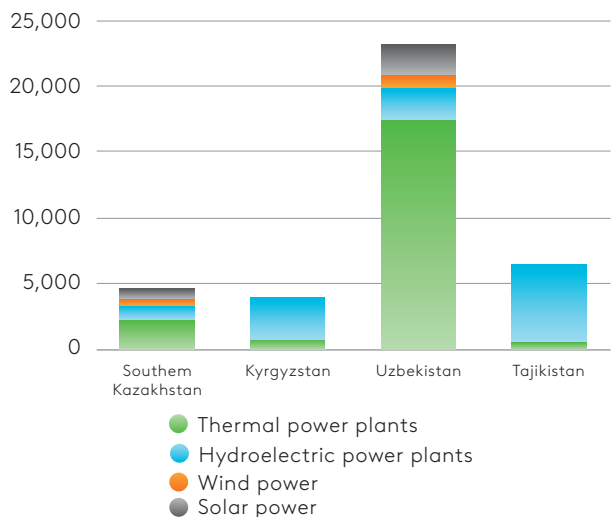
Generation and Consumption within the CAPS Technical Perimeter

Central Asia has historically been interconnected in terms of electricity. The countries in the region inherited from the Soviet Union both uniform technical standards and well-developed cross-border electricity transmission capacity (EDB, 2008). The main question now is: what portion of this interconnectedness can be safely utilized for trade, emergency support, RE integration, grid balancing, and investment development?

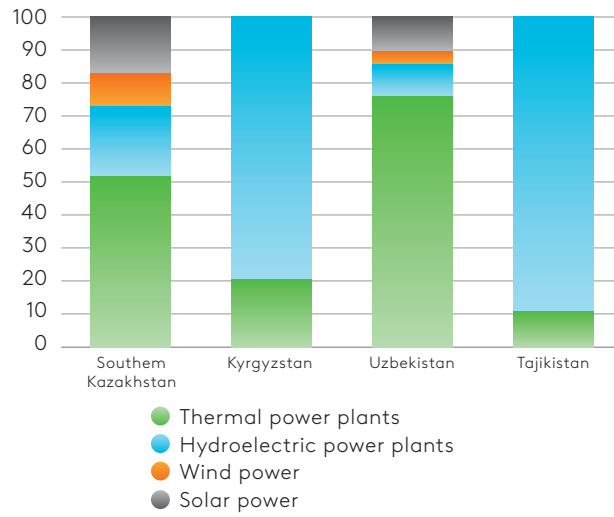
In this section, the CAPS is treated as a single technical entity. The power systems of Uzbekistan, Kyrgyzstan, Tajikistan, and the southern part of Kazakhstan operate in parallel within the CAPS. The isolated power plants in Turkmenistan and the northeastern part of Afghanistan’s power system interact with the CAPS via islanded configurations. This distinction is important because the geographical concept of Central Asia is broader than the technical boundary of the CAPS.

For a comparable assessment of the technical condition of the CAPS, the latest agreed-upon operational data from CDC Energia are used below, covering primarily 2024 and the 2024/25 winter operating period. As of January 1, 2025, the installed capacity of power plants in the CAPS totaled 38.6 GW. Uzbekistan accounts for the largest share of this capacity—23.1 GW. Southern Kazakhstan has 4.77 GW, Kyrgyzstan has 4.13 GW, and Tajikistan has 6.55 GW. The generation and capacity mix reveals significant heterogeneity within the region.

↓ Figure 2. Structure of Installed Capacity in the Central Asia Power System as of January 1, 2025, MW



↓ Figure 3. Breakdown of Installed Capacity in the Central Asia Power System as of January 1, 2025, %



Source: CDC Energia.

In 2024, electricity generation in the CAPS amounted to 125.4 billion kWh, while consumption totaled 142.2 billion kWh. The gap between consumption and generation is explained by the system boundary: northern Kazakhstan, which lies outside the CAPS, supplies large volumes of electricity to southern Kazakhstan, which lies within it. The 13.5% increase in consumption in 2024 should not be interpreted as a long-term

trend: the statistics were influenced by Tajikistan's return to parallel operation and changes in accounting methods.

These indicators confirm the operational role of interconnections. They are necessary to meet demand, offset seasonal and intraday imbalances, maintain acceptable voltage and frequency levels, and regulate water releases through hydropower facilities. In this configuration, the value of integration is measured not only by the volume of trade, but also by the ability to transmit power to the right node at the right time.

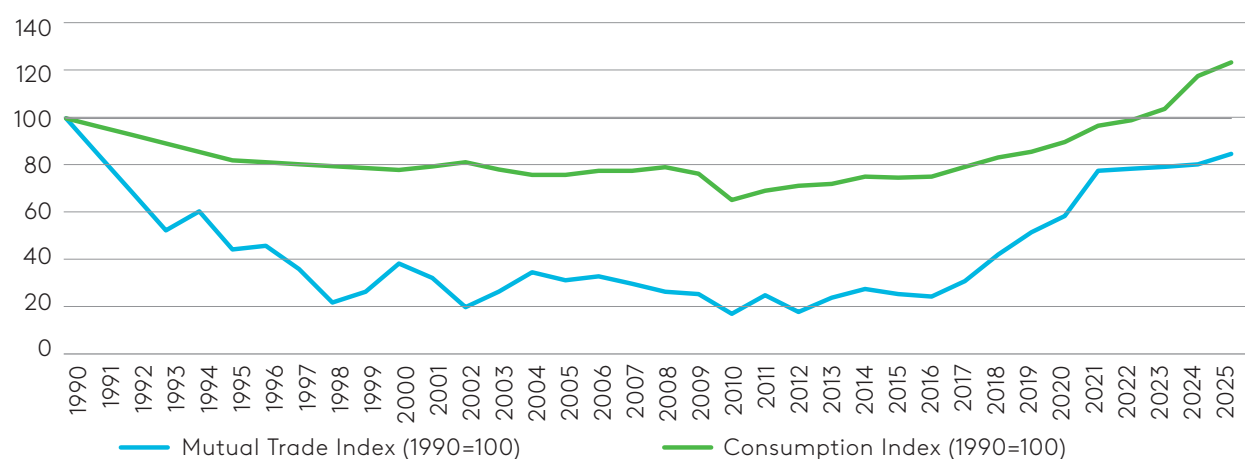
Grid development in many parts of the CAPS is lagging behind the pace of new generation capacity coming online. This is particularly evident against the backdrop of rapid capacity growth in Uzbekistan, including RE, and increased transit loads on existing corridors.

Regional Trade Trends and the Potential for Recovery

The history of regional trade shows that the CAPS already had experience with deep interdependence. In 1990, total technical power flows between the power systems of the Central Asian republics and southern Kazakhstan amounted to 25.5 billion kWh. Historical technical power flows and current trade figures are not entirely comparable categories: the former reflected power transmission and reception between the republics, while the latter are more often accounted for through net power flows and commercial deliveries. In the current net power flow scheme, this historical volume corresponds to approximately 15.1 billion kWh of regional trade.

From 1990 to 2010, trade volumes between countries declined steadily. This was influenced by the countries' efforts to achieve self-sufficiency, a shortage of foreign currency for electricity purchases, the withdrawal of certain power systems from parallel operation, as well as constraints on generation and transmission networks. The lowest level was recorded in 2010 (2.5 billion kWh) following the separation of the Tajik power system from the CAPS.

↓ **Figure 4. Inter-Republican Electricity Trade Volumes in the CAPS (1990 = 100)**



Source: CDC Energia.

In recent years, trade has begun to recover. This has been facilitated by economic growth in the region's countries, Tajikistan's return to parallel operation, the operation of designated Turkmen generators in islanded configurations with the CAPS, the transit of electricity from Russia to Kyrgyzstan via Kazakhstan, and the expansion of power flows between neighboring systems.

↓ Table 1. Comparison of Cross-Border Electricity Trade Indicators in Selected Markets

Power System/Market	Cross-border exchanges in 2024, billion kWh	Consumption in 2024, billion kWh	Share of cross-border exchanges in consumption
Central Asia Power System	12.1	142.2	8.5%
EU	485.6	2,773.2	17.5%
Canada (trade with the U.S.)	58.9	610.6	9.6%
United Kingdom	33.4	318	10.5%
Italy	51	312.3	16.3%
PJM, U.S.	64.2	784	8.2%

Note: The international estimates refer to markets with varying sizes, income levels, exchange rate regimes, degrees of liberalization, and institutional maturity of regulation.

Sources: EDB analysis based on data from the ENTSO-E Statistical Factsheet 2024, the Canada Energy Regulator, Annual Trade Summary: Electricity, 2024, the UK Department for Energy Security and Net Zero, Digest of UK Energy Statistics 2025, Terna, Electricity Consumption 2024, and Monitoring Analytics, 2024 State of the Market Report for PJM.

In 2024, the total volume of regional trade in the CAPS amounted to 12.1 billion kWh. This is nearly five times higher than the 2010 level, but approximately 20% lower than the 1990 level in the balance-of-flows scheme. At the same time, consumption in the CAPS rose from 118.2 billion kWh in 1990 to 142.2 billion kWh in 2024.

The limited growth in exchanges is due to a number of factors. Although regional trade is recovering, significant factors include not only commercial conditions, but also grid constraints, fuel shortages and a lack of available reserves during the winter months, hydrological conditions, insufficient formalization of short-term transactions, and the slow development of digital grid infrastructure.

Part of the trade depends on the hydropower plants' water and energy operating regime. Power generation in upstream countries is tied to water release schedules in the summer, while reverse deliveries in winter help upstream countries meet their demand. As electricity consumption in Kyrgyzstan grows and the water level of the Toktogul Reservoir fluctuates, the traditional model becomes fragile. Future trade is becoming more dependent on grid infrastructure, settlement discipline, confirmed available transmission capacity, and new market mechanisms.

The inclusion of Turkmen power supplies resulted in increased flows and demonstrated the value of this external resource and, at the same time, the limitations of the current system. The isolation of the Mary TPP and Lebap TPP generators into islanded operation¹ made it possible to significantly increase supplies, including transit to Kyrgyzstan via Uzbekistan. Further expansion of these flows is limited by internal bottlenecks within Uzbekistan between the western, central, and Fergana parts of the power grid.

¹ Island operation — the separation of a specific generating facility, grid section, or load area from the main power system to operate on another power system or an isolated load. This mode allows for limited power transfers without full synchronization of the power systems, but it has lower scalability, requires separate dispatch control, and does not provide for a full exchange of reserves and ancillary services.

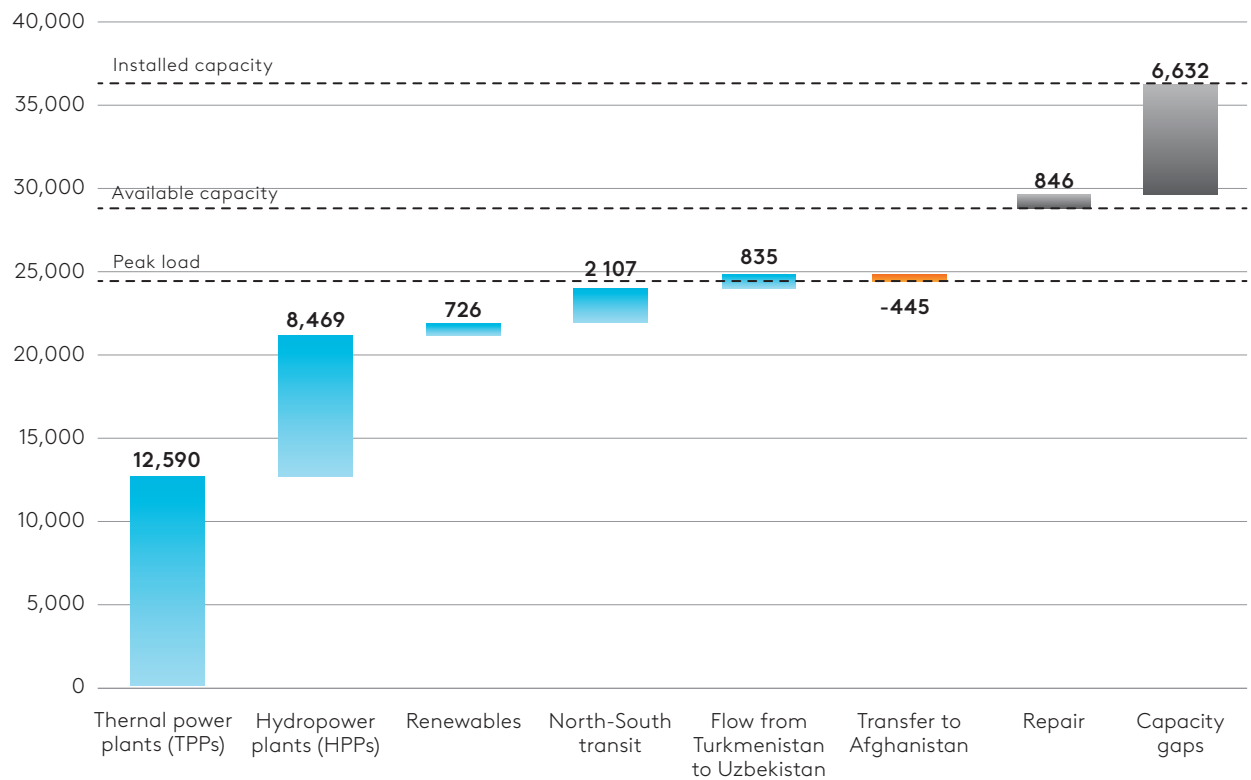
Regional trade is already having a system-wide impact. Its further growth requires a transition from historically established mechanisms to a more manageable architecture. Such a transition is consistent with the “Middle Path” strategy: countries maintain their national priorities, while simultaneously deriving greater benefits from the shared network, reserves, and seasonal complementarity.

Available Capacity and Annual Peak Load

System stress in the CAPS is most evident during the annual peak. The 2024 peak occurred on December 10 at 7:00 p.m. and reached 24.3 GW. At that time, southern Kazakhstan, Kyrgyzstan, Uzbekistan, and Tajikistan were operating in parallel with the Unified Energy System (UES) of Kazakhstan and UES of Russia. The 500 kV ring was closed and all lines were in service. On the North–South transmission interface in Kazakhstan, however, power flow reached 2,328 MW against an operating limit of 2,100 MW.

The power balance for this hour shows the gap between installed, available, and actually utilized capacity. On the day of peak demand, installed capacity was 36.4 GW, available capacity was 28.8 GW, and the total of underutilized capacity and constraints was 6.6 GW (+ approximately 0.85 GW under maintenance).

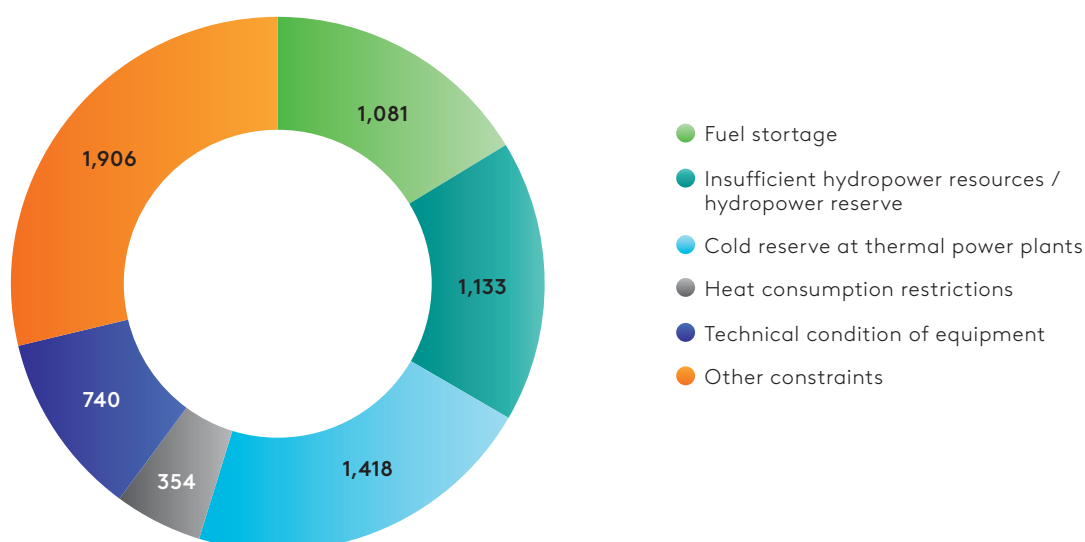
↓ Figure 5. Power Balance of the CAPS During the Peak Hour (December 10, 2024, 7:00 p.m.)



Source: CDC Energia.

The capacity unavailable during the peak hour reflected several constraints: fuel shortages accounted for 1,081 MW, hydrological constraints for 1,133 MW, thermal units in cold reserve for 1,418 MW, heat-supply obligations for 354 MW, equipment condition for 740 MW, and other constraints for 1,906 MW.

↓ Figure 6. Causes of Capacity Unavailability During the Annual Peak Hour, MW



Source: CDC Energia.

The data highlight a fundamental difference between installed capacity and actually available capacity. When assessing reliability, what matters is not the total capacity of the facilities, but rather the capacity that can be mobilized and delivered through the grid during a critical moment. In the CAPS, part of the capacity is limited by fuel, part by water, part by technical condition, and part by the operating conditions of thermal power plants and heat-supply obligations. Therefore, it is advisable to evaluate regional cooperation in terms of resource availability during critical hours, rather than solely in terms of total megawatts.

The role of hydropower plants is particularly noticeable during peak hours. During the evening winter load, RE sources contributed 726 MW, while hydropower plants accounted for 8,469 MW of the power plants' total output. This confirms the importance of hydropower as a key resource for load regulation. At the same time, the capabilities of hydropower plants are limited by water management regimes, reservoir levels, and the domestic demand of upstream countries.

Short-term trading, RE integration, emergency support, and the ancillary services market—given limited reserve margins—require a prior understanding of available capacity, confirmed transmission capacity, the quality of dispatch control, and the readiness of fast reserves.

Transmission Interfaces and Available Transfer Capacity

Grid constraints are the main technical barrier to scaling up trade. Major transmission lines and monitored transmission interfaces often operate with minimal stability margins. During the 2024/25 winter operating period, a number of sections operated with actual power flows exceeding planned and permissible values.

Physical interconnection does not equal commercially available transmission capacity. The existence of a line between power systems does not mean that additional commercial power can be transmitted over it at any given moment. For trading

purposes, what matters is the confirmed available transmission capacity, taking into account the N-1 stability criterion², voltage, emergency protection systems, and the current grid operating conditions.

↓ **Table 2. Examples of Congested Monitored Transmission Interfaces in the CAPS, 2024/25 Winter Operating Period**

Section	Plan, MW	Actual, MW	Allowable, MW	Actual-to-allowable, %
North–South Transit in Kazakhstan	1,900	2,395	2,100	114
North–South Transit in Kazakhstan (extended)	2,100	2,570	2,300	112
Kazakhstan–Kyrgyzstan	1,300	1,600	1,100/1,300	123
CAPS — Southern Kazakhstan	1,700	2,340	2,300	102
Uzbekistan–Kyrgyzstan (Fergana Power Hub)	1,960	2,940	1,800/2,600	113
Sogdiana–Guzar–Talimarjan (within Uzbekistan)	1,070	1,570	1,500	105

Source: CDC Enerгия.

An analysis of operational data from CDC Enerгия reveals three key characteristics of the grid. First, the existence of a transmission line does not guarantee the transmission of purchased or sold electricity. Second, many constraints are of a mixed nature: some interfaces are cross-border, while others are internal, but their impact is equally significant for regional trade. Third, congestion indicates that the expansion of trade, the exchange of balancing energy, and the growth of RE sources will be limited without the appropriate measures.

Internal Grid Constraints and Their Impact on Cross-Border Flows

Many barriers to regional trade arise within national networks. Therefore, the development of cross-border routes should be closely planned and coordinated with the expansion of domestic grids.

The growth of RE in Uzbekistan has regional significance. Daily surpluses of solar power generation can be a valuable resource for neighboring countries; however, when grid constraints exist, they become a source of curtailment of RE and compete with transit energy from other countries. In such a situation, investments in Uzbekistan’s domestic grids have both national and regional effects.

The southern part of Kazakhstan depends on power flows from northern Kazakhstan via the North–South transit corridor. The capacity of this transit corridor is used

² N-1 criterion: The system must withstand the sudden failure of any single key component (*line, transformer*) without causing a system failure.

almost entirely to supply Kazakhstan's own consumers. Therefore, uncompensated imbalances in the CAPS can place an additional load on this corridor and create a risk of overload. In the event of an emergency shutdown of the North–South transit line, a power flow of approximately 2,000 MW to the southern regions of Kazakhstan would cease, which would significantly complicate the emergency response process in the CAPS.

Kyrgyzstan remains an important source of hydropower flexibility for the CAPS, but the resource available for exports and regional balancing is shrinking. Rising domestic demand and low levels in the Toktogul Reservoir constrain summer exports and winter flexibility. In recent years, Kyrgyzstan has relied on imports from Kazakhstan, Uzbekistan, and Russia to preserve reservoir levels and reduce the risk of winter shortages.

Tajikistan supplies significant amounts of summer hydropower and balancing capacity to the CAPS, but substantial flows are being redispatched due to grid limitations (see [Chapter 3](#) for more details).

Turkmenistan is a potential external source of surplus thermal power. Current supplies to the CAPS are delivered via islanded configurations, with generators and grid elements isolated. While this configuration has allowed for increased trade, it limits further scaling. The condition of the L-512 cross-border line prevents an increase in power output from Turkmenistan, and further expansion of supplies depends on the development of technical specifications for Turkmenistan's parallel operation with the CAPS and a framework for cooperation with Iran.

In its current configuration, the Afghan route plays a limited role in the power system. Afghanistan's northeastern power grid receives electricity via isolated systems: mainly from Uzbekistan in the winter and from Tajikistan in the summer. Transit through the Puli-Khumri substation is limited due to voltage stability requirements, which makes Afghanistan primarily a receiving market and a promising infrastructure extension of the southern route.

Based on the data analyzed, EDB experts identify five categories of constraints on regional integration: capacity availability, monitored transmission interfaces, internal grid corridors, fuel and water resource constraints, and the quality of digital and dispatch control systems.

The conclusion of this section is that a significant portion of regional constraints lies within individual countries. A new cross-border line may not produce the expected results if the domestic grid is unable to receive, supply, or redistribute capacity. Therefore, investors should consider the relevant cross-border interfaces and domestic corridors holistically, taking into account their mutual influence.



3.

SYSTEMIC ROLES OF COUNTRIES
IN THE REGIONAL RELIABILITY
AND FLEXIBILITY PORTFOLIO

The practical value of the CAPS stems from the differences in the systemic roles of the participating countries. Some power systems concentrate demand, others offer hydropower flexibility, others serve as transit hubs, and still others can provide external thermal capacity or a destination market for seasonal exports.

This division of roles lays the foundation for regional cooperation. The southern part of Kazakhstan highlights the vulnerability of its transit infrastructure. Kyrgyzstan and Tajikistan provide the region with the low-carbon flexibility of hydropower; its availability, however, is limited by water management regimes, irrigation obligations, and domestic demand in the upstream countries. Uzbekistan is the largest center for demand, generation, transit, and integration of RE. Turkmenistan can serve as an external source of surplus gas-fired capacity under agreed-upon technical conditions. Afghanistan remains a destination market and a promising southern infrastructure extension.

The classification presented below is used in this report as an analytical framework for assessing the complementarity of resources and the constraints of power systems (it does not constitute an official division of roles among countries).

↓ **Table 3. Systemic Roles of Countries and Territories in the Central Asia Power System Architecture**

Country/Loop	Primary role	Primary resource	Main constraint
Southern Kazakhstan	Critical load and transit hub	High demand, connection to Kazakhstan's UES and Russia's UES	North–South transit constraints
Kyrgyzstan	Hydropower-balancing hub with limited surplus resource	Naryn Cascade, Toktogul, peak regulation	Growth in domestic demand, water levels
Uzbekistan	Core of demand, generation, transit, and RE integration	Thermal generation, RE, BESS	Gas availability during winter operation; domestic grid constraints
Tajikistan	Supplier of summer hydropower and balancing capacity	Vakhsh Cascade, Nurek, Rogun	Output constraints and seasonality
Turkmenistan	External source of surplus thermal capacity	Gas-fired generation, 15–50% reserve	Islanded systems and synchronization
Afghanistan	Destination market and prospective southern extension	Demand, southern corridor	Stability constraints and islanded systems

Source: EDB assessment based on data from CDC Energia.

This structure is directly relevant to the “Middle Path” strategy. Regional cooperation makes it possible to leverage the various strengths of power systems without compromising national strategies. It helps improve reliability, maintain energy affordability, and reduce the cost of integrating RE sources through shared reserves and flexible capacity.

Southern Kazakhstan

The southern part of Kazakhstan is part of the CAPS as a major load center connected to the rest of Kazakhstan's power grid via the North–South transit line. Its power balance is covered by domestic generation and power flows from northern Kazakhstan in roughly a 50/50 ratio, and transit capacity is used almost entirely to serve consumers within Kazakhstan itself. This configuration makes the southern region of Kazakhstan vulnerable to uncompensated imbalances in the CAPS.

In the event of an emergency shutdown of the North–South transmission line, the southern regions of Kazakhstan lose approximately 2,000 MW of power flow. This significantly complicates the emergency response process within the power system and increases the importance of coordinated balance flows, automatic generation control (AGC), emergency protection systems, and the timely exchange of operational data.

The southern part of Kazakhstan also participates in seasonal water-for-energy exchanges with Kyrgyzstan. During the growing season, Kazakhstan receives electricity from Kyrgyzstan as part of reciprocal arrangements related to irrigation water for agricultural consumers. During other periods, Kazakhstan supplies electricity to Kyrgyzstan. In recent years, exports to Kyrgyzstan have exceeded imports from Kyrgyzstan, due to low water levels in the Toktogul Reservoir and rising domestic demand in Kyrgyzstan.

An additional function of the southern zone involves Uzbekistan and the northern loop. Part of the electricity consumption is covered by agreements between economic entities in Uzbekistan and Kazakhstan. Kazakhstan also provides electricity transit services from the Russian Federation to Kyrgyzstan via the networks of KEGOC JSC. The volume of this transit is limited by the capacity of the North–East–South corridor and amounts to approximately 30 million kWh per month.

From the perspective of this report's analytical framework, the system-wide importance of southern Kazakhstan lies in its role as a major load center and transit-sensitive hub. This is the EDB's conclusion, based on data regarding the load on the North–South corridor, the balance structure, and the impact of imbalances in the CAPS. Southern Kazakhstan's role in the regional architecture is that it highlights the cost of insufficient grid flexibility. What matters for the market is not only the volume of electricity that can be bought or sold, but also the reliability of the transit corridor through which this energy flows. Therefore, projects to strengthen the northern and Kazakhstan-Kyrgyzstan interconnections are important for the entire CAPS.

Kyrgyzstan

Historically, Kyrgyzstan has been one of the main hydropower-balancing hubs of the CAPS. As of January 1, 2025, the installed capacity of the Kyrgyz power system was 4.13 GW, of which 3.26 GW, or 79.1%, comes from hydropower plants. This structure makes the country an important source of peak power, seasonal balancing, and water-energy exchanges.

The Naryn Cascade and the Toktogul Reservoir remain central to Kyrgyzstan's role. The Toktogul Reservoir has a design full capacity of 19.5 billion m³ and serves the function of long-term regulation. The Toktogul Hydropower Plant, with a capacity of 1,440 MW (after rehabilitation), operates to ensure water releases and cover the most demanding portion of the load schedule.

The system-wide value of Kyrgyz hydropower plants lies in their operational flexibility. According to data from CDC Energia, it takes 1–2 minutes to start a hydroelectric unit from a standstill in turbine mode with synchronization and full power output, and 15–30 seconds when the unit is idling. This capability is useful for secondary regulation, covering peak demand, providing emergency reserve capacity, and balancing variable RE sources.

Kyrgyzstan's hydropower resource available for export and regional balancing is shrinking. Electricity consumption increased from 14.6 billion kWh in 2014 to 19.3 billion kWh in 2025, with the pressure particularly acute during low-water periods, when system conditions depend heavily on reservoir levels. Even higher imports from neighboring systems have not yet produced a sustained recovery in the Toktogul Reservoir.

The Kambarata-1 Hydropower Plant is viewed as a project capable of strengthening the stability of Kyrgyzstan's power grid and preserving the regulatory function of the Toktogul Reservoir. In the regional context, this is a major seasonal regulation project with the potential to increase the availability of water resources, reduce tensions in water-energy exchanges, and enhance the flexibility of the CAPS.

Within the EDB's analytical framework, Kyrgyzstan is viewed as a hydropower-balancing hub with high operational flexibility but limited surplus resource, which depends on domestic demand, water availability, and the condition of the grid. For regional cooperation, Kyrgyzstan's significance lies in providing remunerated hydropower flexibility. This service includes on-demand power adjustments, frequency support, coverage of evening peaks, and water conservation, all of which can assist neighboring systems in integrating RE sources. The cost of such flexibility is linked to reservoir regulation, operational wear and tear on equipment, water management obligations, and Kyrgyzstan's national energy security. Therefore, this function can be viewed as a measurable and compensable regional ancillary service rather than as a free resource.

Uzbekistan

Uzbekistan is the largest power system in the CAPS. As of January 1, 2025, the installed capacity of Uzbekistan's power plants totaled 23.1 GW. Of this, 17.54 GW came from thermal power plants, 2.26 GW from hydropower plants, 900 MW from wind power plants, and 2.4 GW from solar PV plants.

Uzbekistan's grid carries power from Turkmenistan, supplies power to Kyrgyzstan, receives summer hydropower from Tajikistan and Kyrgyzstan, connects to Afghanistan, and facilitates power exchanges with southern Kazakhstan. Consequently, internal constraints in Uzbekistan quickly take on regional significance.

Uzbekistan's role consists of four functions: meeting significant demand and providing baseload generation; receiving summer hydropower from upstream countries; serving as a transit bridge between neighboring power systems; and acting as the main regional testing ground for the large-scale integration of RE sources, BESS, and flexible gas-fired generation.

Uzbekistan actively imports cheaper summer hydropower from Tajikistan and Kyrgyzstan. This supports the water management regimes of downstream countries and reduces non-generating spill at hydropower plants in neighboring countries. In this model, electricity becomes part of the water-energy balance, rather than merely a commercial commodity.

The reliability of Uzbekistan's power system in winter depends on fuel supplies. Formally, the generation fleet has a potential surplus capacity of 600 to 1,300 MW even during the harsh winter months. Actual operating conditions show that during the fall and winter, this surplus is often not realized: during sudden cold snaps and evening peak hours, excessive gas consumption causes a drop in gas pipeline pressure that limits the ramp-up capability of gas-fired power plants. Thus, capacity shortfalls can range from 100 to 400 MW.

The solution to this problem was the development of flexible power sources: reciprocating gas engines, combined cycle power plants operating in flexible mode, pumped-storage power plants, and BESS. The commissioning of flexible power units based on gas-engine and gas-turbine units made it possible to reduce the number of start-ups, shutdowns, and outages at traditional thermal power plants by up to 30% and improve their technical and economic performance. Public-private partnerships (PPP) played a key role in this. As of January 1, 2025, the installed capacity of power plants developed under PPPs totaled 3,276 MW, or about 14% of the installed capacity of the Uzbek power system. Some thermal power plants are being privatized, including with the participation of foreign investors.

The growth of RE is changing how Uzbekistan's power system operates. With the large-scale commissioning of new solar and wind power plants, dispatchers are not always able to accommodate all potential generation: conventional generation has a technological minimum, and the grid is not always capable of transmitting daytime surpluses to other demand zones. As a result, RE generation is forced to be curtailed. However, curtailment does not mean that the associated financial costs disappear. Depending on the terms of the PPA, curtailment of generation may create compensation obligations to the generator; therefore, part of the cost of unused electricity remains with the buyer or the system operator and may ultimately be reflected in tariffs or budgetary support.

The example of the 500 MW Bash wind farm is telling—it has increased the load on existing grids in the Samarkand-Bukhara section of Uzbekistan's power system and reduced the volume of electricity imports from Turkmenistan. The large-scale deployment of BESS in Uzbekistan's power system does not ensure full utilization of the projected daily surpluses of solar generation. However, as the BESS fleet grows, by 2030 it may become the primary tool for:

- frequency regulation;
- covering the evening peak;
- reducing curtailment of RE;
- providing ancillary services.

This is particularly important for Uzbekistan, given its stated goal of reaching 4.3 GW of storage capacity.

Uzbekistan serves as the central hub for the CAPS. The extent of regional integration depends largely on how this central network position among neighboring countries is utilized to promote flexibility and trade, reduce curtailment of RE, and enhance the bankability of new projects.

Tajikistan

Tajikistan provides significant hydropower resources to the CAPS. As of January 1, 2025, the installed capacity of the Tajik power system was 6.55 GW, of which 5.8 GW, or 89%, came from hydropower plants. This mix makes Tajikistan one of the region's main sources of low-carbon power generation and load regulation.

Until 2009, Tajikistan's power grid operated as part of the CAPS. Following a period of isolated operation, the country commissioned the 670-MW Sangtuda-1 Hydropower Plant, the Sangtuda-2 Hydropower Plant with a capacity of 220 MW, the Dushanbe Thermal Power Plant-2 (four units with a total capacity of 400 MW), two units of the Rogun Hydropower Plant with a capacity of 120 MW each (at reduced head), as well as a number of small hydropower plants. New 110–500 kV transmission lines were built, including the south–north transit line and the Rogun–Dushanbe transmission line.

On June 7, 2024, the power grid of the Republic of Tajikistan was reintegrated into the CAPS. This has expanded the region's resource base and reintegrated one of the key sources of summer hydropower and a balancing resource into the common grid.

Under the agreements, electricity is supplied to Uzbekistan from June through September, while electricity is received from Uzbekistan from November through December and from March through April. Summer supplies exceed winter supplies by two to three times.

Tajikistan's role is becoming more valuable as solar and wind generation expand in Uzbekistan and Kazakhstan. According to CDC Energia, Uzbekistan makes extensive use of Tajikistan's balancing capability during summer exports and reciprocal winter supplies. In operational terms, Tajik hydropower can act as a flexible balancing resource for Uzbekistan's solar generation.

The main constraint remains the available transmission capacity of the domestic grid. After parallel operation was restored, Tajik electricity was primarily received at the Surkhandarya power hub in Uzbekistan. At the same time, 40% of the planned volume was returned via a substitution scheme from the busbars of the Syr Darya Thermal

Power Plant to a designated power zone in the Sughd Region of Tajikistan. Meanwhile, non-generating spill continued at Tajik hydropower plants due to limitations in the 220 kV internal grids.

Tajikistan's future role is linked to the Vakhsh Cascade, the Nurek Hydropower Plant, and the Rogun Hydropower Plant. In the Vakhsh Cascade, the main regulating asset is the Nurek Reservoir, a seasonal regulation reservoir with a usable volume of 4.5 billion m³. The Rogun Reservoir, with a total volume of 13.3 billion m³, is located upstream of the Nurek Reservoir and is classified as a multi-year regulation reservoir.

Once the Rogun Hydropower Plant reaches its design capacity, the operating conditions of the Vakhsh Cascade may become more predictable for regional trade. Regulating the flow will help reduce non-generating spill and tailor power deliveries to match purchased electricity volumes. CDC Energia also points to a draft trade agreement on the principles of cooperation with the Rogun Hydropower Plant, developed by the World Bank in collaboration with interested countries in the region.

For the CAPS, Tajikistan is a potential provider of low-carbon balancing, operating reserves, and ancillary services. Realizing this role depends on grid deliverability, contractual arrangements, settlement metering, and transparent remuneration for flexibility. With these conditions in place, Tajikistan could become one of the region's key providers of hydropower flexibility.

Turkmenistan

Turkmenistan is a potential external source of surplus thermal capacity. Its power system operates separately from the CAPS, and individual power plants interact with it via islanded configurations. Turkmenistan's role in the system stems from its ability to provide the region with surplus gas-fired generation during periods of power shortages in neighboring systems.

CDC Energia characterizes the Turkmen power system as having excess capacity. It fully meets the country's own electricity needs and, when demand exists, can export electricity to other countries. All power plants run on Turkmen natural gas from nearby gas fields, and capacity reserves range from 15 to 50 percent, depending on the season and export volumes.

Until 2003, Turkmenistan's power grid operated as part of the CAPS, connected to the Uzbek power grid via 220–500 kV transmission lines. It then switched to operating in parallel with Iran's power grid via two 220 kV transmission lines. Currently, Turkmenistan exports electricity to Iran, Turkey, Afghanistan, and Uzbekistan.

Power supply to the CAPS is organized through islanded systems. Turkmenistan allocated generators from the Mary Thermal Power Plant via the 500 kV Mary–Serdar–Karakul transmission line, as well as generators from the Lebap Thermal Power Plant via the Lebap–Karakul route. This scheme has made it possible to increase regional trade, including supplies to Uzbekistan and transit to Kyrgyzstan via Uzbek networks; however, its scale is limited by the condition of cross-border and domestic transmission lines.

Turkmenistan's future role is linked to the technical requirements for parallel operation with the CAPS. The Coordinating Electric Power Council of Central Asia (CEPC CA) has previously confirmed the technical feasibility of such a connection, provided that the emergency-control scheme is implemented and the design solutions are put into practice. This issue is also related to the Turkmenistan–Iran transmission line and a possible controlled scheme via a direct current interconnection (DCI)³.

For the CAPS, Turkmenistan's role lies in its ability to provide dispatchable thermal capacity during periods of high demand. This can be achieved on a sustainable basis only under coordinated technical conditions, a reliable interconnection scheme, transparent settlement arrangements, verified transmission capacity, and rules for emergency support.

Afghanistan

Afghanistan's Northeast Power System (NEPS) operates with the CAPS in islanded configurations and serves as a receiving market. The connected parts of Afghanistan's power system in these configurations do not have their own generation capacity; therefore, their impact on the CAPS's operating condition is primarily related to consumption and the direction of power flows.

The NEPS is connected to the CAPS via 220 kV transmission lines. During the winter, power is mainly supplied from the Uzbek power grid via the Surkhan–Puli-Khumri–Kabul route; during the summer, it is supplied from the Tajik power grid via the Sangtuda–Puli-Khumri–Kabul route. The use of these lines for transit through the Puli-Khumri substation is limited due to voltage stability requirements, which results in the busbar systems being split at most NEPS substations.

Afghanistan's future role is linked to the development of 500 kV transmission networks and southern export routes. Of particular importance are the construction of the 500 kV Surkhan Substation–Khoja Alvan Substation transmission line and the further development of the Khoja Alvan–Kabul connection. Once these projects are implemented, Afghanistan could achieve a more interconnected infrastructure configuration, provided that stability requirements are met and a contractual framework is in place.

CASA-1000 reinforces Afghanistan's importance as a southern transit corridor. At the same time, Afghanistan's current role in this architecture remains neutral and limited: it serves as a destination market and a promising infrastructure extension of the southern route. Its future transit function depends on the development of the networks, their stability, the payment model, and the operating regime of the relevant lines.

³ A direct current interconnection (DCI) is a node that connects two alternating current power systems via an intermediate direct current link. This configuration allows power to be transmitted without full synchronization of the power systems, enables the control of power flow, and limits the propagation of fault disturbances between the systems. In international practice, this principle is often referred to as "back-to-back HVDC."

Russian Federation

Separately, in the context of system roles, it is worth noting the connection between the CAPS and the Unified Energy System of Russia (UES). The interaction between the power systems of Russia and Kazakhstan produces operational and reliability benefits for the broader synchronous area.

Power exchange between the European part of Russia's UES and the Siberian Power System via Kazakhstan's grids has traditionally been conducted as follows. During nighttime hours of minimum load in the European part of Russia's UES, power and energy flowed eastward to the Siberian Power System; conversely, during evening hours of maximum load in the European part of Russia, power and electricity were supplied westward from the Siberian Power System. This made it possible to achieve the regulatory effect of balancing the daily load schedule in the European part of Russia by using the power grids of northern Kazakhstan to facilitate the exchange of power flows between the two Russian regions.

The strong interdependence of the Central Asian and Russian power systems was most clearly demonstrated during the response to accidents at the Sayano-Shushenskaya Hydropower Plant on August 17, 2009, and in the CAPS on January 25, 2022. Transit from the integrated power systems of the Urals and the Middle Volga through Kazakhstan's territory made it possible to avoid a cascading outage and a blackout in the Siberian Power System. At the same time, Kazakhstan also used its own generating capacity to help partially compensate for the shortfall in output from the Sayano-Shushenskaya HPP.

A cascading emergency in the CAPS on January 25, 2022, led to a large-scale blackout affecting most of southern Kazakhstan, Kyrgyzstan, and Uzbekistan. The incident, which began in Uzbekistan, resulted in an emergency disconnection of the North–East–South Kazakhstan transmission line, cutting off power to a significant portion of consumers in the CAPS. In the first few hours after the incident, Kazakhstan sharply increased its electricity exports to Russia to 750 MW, thereby balancing the resulting excess capacity (prior to the incident, electricity had been flowing from Russia to Kazakhstan).

These examples illustrate the contribution of cooperation between Russia's UES, Kazakhstan's UES, and the CAPS to ensuring the reliability of electricity supply. Nevertheless, it is important for the region to develop its own reserves, internal grid, and emergency response systems. The resilience of the systems depends not only on the technical readiness of the North–South transit corridor in Kazakhstan, but also on external regulatory conditions. These factors are beyond the control of the CAPS member states and require scenario-based assessments, diversification of reserves, and the maintenance of alternative emergency support mechanisms.

4.

GRID, DIGITAL, AND RESERVE CONDITIONS FOR INTEGRATION



Physical interconnection within the CAPS already exists to a large extent. Its effectiveness will be determined by the ability to transmit power in a specified direction, maintain real-time operation, ensure the availability of reserves, and adapt new RE sources to the power system's requirements.

Regional integration requires the removal of a number of constraints. These constraints arise at the intersection of the grid, fuel, water, digital control, protective relaying, emergency control, commercial metering, and rules for connecting new facilities. Taken together, these constraints reduce the reliability of the CAPS: they lead to deviations from scheduled interchange, the exhaustion of transmission capacity at certain transit points, and the system operating with minimal stability margins.

Grid Constraints at Domestic and Cross-Border Interconnections

The grid constraints of the CAPS are of a mixed nature. Some of them occur at cross-border interfaces. Others are located within national power systems, but affect regional trade no less than cross-border lines. Therefore, it is useful to view the grid as a single operational loop, where internal and interstate constraints can equally affect the availability of trade, emergency support, and RE integration.

During the 2024/25 winter operating period, several key monitored sections operated above their permissible limits. At sections L-530, L-532, and L-539, the actual flow reached 2,395 MW, compared to the permissible limit of 2,100 MW; at the expanded sections L-530, L-532, L-539, L-2303, and L-2029, the actual flow was 2,570 MW, compared to the permissible limit of 2,300 MW. At the interface of L-514, L-A-G, L-Kemin-Zap., L-228, and AT-3 Shu, the actual flow was 1,600 MW, compared to the permissible level of 1,100/1,300 MW. The flow into the Fergana power hub reached 2,940 MW, compared to the permissible level of 1,800/2,600 MW.

For regional trading, net transfer capacity and available transfer capacity (NTC/ATC)⁴ are more relevant; these should be calculated using current system conditions, the N-1 security criterion, stability and voltage limits, protection and emergency-control constraints, and already allocated schedules.

Intra-system constraints quickly become regional. Uzbekistan is the central grid hub of the CAPS, so constraints in its western part—the Samarkand-Bukhara corridor and the Fergana power hub—immediately affect several areas: RE generation, power imports from Turkmenistan, exports to Kyrgyzstan, hydropower imports from Tajikistan, and the power balance with southern Kazakhstan. The commissioning of the 500 MW Bash wind farm led to additional load on the grids in the Samarkand-Bukhara section of the power system and a reduction in supplies from Turkmenistan. The commissioned BESS facilities, with a capacity of 1,450 MW and a storage capacity of 2,400 MWh, are considered insufficient to absorb large daytime surpluses of solar generation. Under these conditions, strengthening Uzbekistan's internal grids could yield results comparable to those of a new cross-border transmission line.

⁴ NTC (Net Transfer Capacity) — the maximum power exchange between power systems that the grid can handle while meeting reliability requirements (N-1 criterion, stability, voltage), minus the reliability reserve. ATC (Available Transfer Capacity) — the portion of the NTC that remains available for new transactions after subtracting already scheduled transactions.

↓ Table 4. Grid Constraints of the Central Asia Power System by Key Interfaces

Interface/Zone	How it manifests	Impact on integration
Kazakhstan — CAPS/ North–South Transit in Kazakhstan	L-530, L-532, L-539, and expanded sections operate near or above permissible values.	Limits the stability of the northern loop and the ability of Kazakhstan’s southern zone to receive or transmit power
Kazakhstan–Kyrgyzstan	Actual power flow through the L-514, L-A-G, L-Kemin-Zap., L-228, and AT-3 Shu groups reached 1,600 MW.	Limits seasonal mutual power exchanges and the use of Kyrgyz hydropower flexibility
Uzbekistan–Kazakhstan	For the L-501, L-509, L-555, L-2-Ch, and L-2-D groups, the actual power flow was close to the permissible level.	Restricts trade between the largest hub of the CAPS and southern Kazakhstan
Uzbekistan — Kyrgyzstan/Fergana Power Hub	Power flow to the Fergana power hub reached 2,940 MW, while the permissible level is 1,800/2,600 MW.	Affects supplies to Kyrgyzstan, the system operation of the Fergana Hub, and the future operation of connected external transmission lines
Uzbekistan — Tajikistan	The intake of Tajik electricity is limited by adjacent hubs and internal grids.	Reduces the utility of summer hydropower and Tajikistan’s potential as a balancing resource
Turkmenistan–Uzbekistan	The delivery of Turkmen capacity depends on the condition of Uzbekistan’s cross-border and domestic grids.	Limits the extent to which Turkmenistan can be used as an external source of thermal power
Western and Samarkand–Bukhara regions of Uzbekistan	RE generation and transit from Turkmenistan compete for grid capacity.	Illustrates the interconnection between RE, transit, and domestic grid projects

Source: Adapted by EDB experts based on CDC Energia.

The situation is similar in the north—the North–South transit line in Kazakhstan is used to meet the load demand of Kazakhstan’s southern regions and, at the same time, affects the stability of the CAPS. Uncompensated imbalances can be offloaded onto this transit line and increase the risk of overload. Therefore, the development of regional trade largely depends on adherence to operational discipline regarding balance flows, consideration of available transmission capacity, and transparent rules for the use of transmission lines.

The principle of “one constraint—one systemic effect—one project or set of projects” is important for evaluating and prioritizing projects. Each power line, substation, digital system, or emergency response solution should be evaluated in terms of which section of the grid it relieves, what increase in transmission capacity it provides, how much it reduces curtailment of RE, and how it improves overall reliability.

Capacity Availability

The state of the grid determines whether power can be transmitted. The availability of fuel and water resources determines whether the necessary power is available when needed. For the CAPS, this is a fundamental difference: the region's installed capacity is significantly higher than the load during peak hours, but part of that capacity is unavailable due to fuel constraints, hydrological conditions, cold reserve requirements, and the technical condition of the equipment.

As shown in [Chapter 2](#) (the annual peak hour on December 10, 2024), a significant portion of the rated capacity is unavailable due to fuel, hydrology, cold reserve, and technical condition.

↓ **Table 5. Resource Constraints on Available Capacity in the Central Asia Power System**

Constraint	Where it manifests	How it affects integration	Possible solutions
Fuel shortage	Uzbekistan, certain thermal power plants during the fall and winter months	A formal surplus of capacity does not always translate into available reserve capacity when it is needed most.	Fuel planning, flexible gas turbine/gas-fired units, emergency support, BESS
Hydrological constraints	Kyrgyzstan, Toktogul, Naryn Cascade	Available hydropower flexibility is decreasing, especially at low reservoir levels.	Hydropower operating regimes, Kambarata HPP-1, flexibility payments
Hydropower generation constraints	Tajikistan, 220 kV internal grids, Surkhandarya node	Tajikistan's summer hydropower is not fully utilized due to grid constraints.	Strengthening connections between Tajikistan and Uzbekistan, Datka-Sughd, Syr Darya/ACWA-Sughd
Cold reserve at thermal power plants	Thermal power systems in the region	Capacity exists, but its rapid utilization is limited	Reserve mechanisms, ancillary services, modernization of startup procedures
Technical condition of equipment	Thermal power plants, hydropower plants, grids	Reduces actual resource availability and increases the failure rate	Maintenance program, digital monitoring, prioritization of critical components

Source: Adapted by EDB experts based on CDC Energia.

In Uzbekistan, the main resource risk is related to gas availability and pressure in the gas transmission system. In Kyrgyzstan, the constraint is related to water and rising domestic demand. The Toktogul Reservoir remains the main balancing resource of the Naryn Cascade, but the reserve of available flexibility is shrinking. Rising consumption is reducing the cascade's ability to simultaneously meet domestic demand, conserve water, and provide regulation to the region. In Tajikistan, the key constraint relates to grid infrastructure ([Chapter 3](#)).

Looking ahead to 2035, the countries of Central Asia have announced a large-scale expansion of their power generation capacity. According to EDB estimates based on national strategic plans, the total new capacity will amount to at least 62.9 GW and will include RE, hydropower, thermal power, and nuclear power (Vinokurov et al., 2026). The scale of the planned additions means that, in the long term, the key issue is shifting from the number of megawatts installed to the quality of their integration into the power grid: will the new capacity be available when needed, secured with fuel or water, possess the necessary flexibility, and be able to deliver electricity via the grid?

The structure of planned capacity additions varies significantly by country and technology, creating potential for complementarity at the regional level. Kazakhstan is building a diversified portfolio of thermal, nuclear, and renewable generation; Uzbekistan is focusing on the large-scale deployment of solar and wind capacity, while developing flexible gas-fired generation and energy storage; and Kyrgyzstan and Tajikistan are primarily expanding hydropower in combination with RE sources. These resources perform different system functions. Therefore, the regional value of the announced additions depends not only on their total volume but also on how coordinated the development of generation, reserves, storage facilities, grids, and inter-system exchanges will be.

↓ Table 6. Announced Plans for New Power Generation Capacity in Central Asia Through 2035, GW

Country	Additional generating capacity, GW
Kazakhstan	26.0
Uzbekistan	25.0
Kyrgyzstan	5.9
Tajikistan	5.7
Turkmenistan	0.3
TOTAL	62.9

Source: EDB estimate based on strategic plans.

It is important to note that the projected surplus is not necessarily a positive outcome either. New power plants must be sufficiently utilized; otherwise, their capacity utilization factor will decline, and the investment burden will be spread across a smaller volume of net generation. This applies not only to RE sources, where curtailment directly worsens project economics, but also to thermal, hydroelectric, and peaking capacity: if there is uncoordinated overcapacity, some assets will operate fewer hours, while some deficit areas will still experience a lack of reliable coverage due to grid, fuel, or operational constraints. As a result, the region may end up with a paradoxical situation: a nominal surplus of installed capacity while still facing a shortage of available capacity during peak hours.

This is precisely why it is important to consider capacity availability not only at the national level, but also at the regional level. Surplus capacity has system-wide value only when it can be transmitted through the grid, incorporated into the dispatch

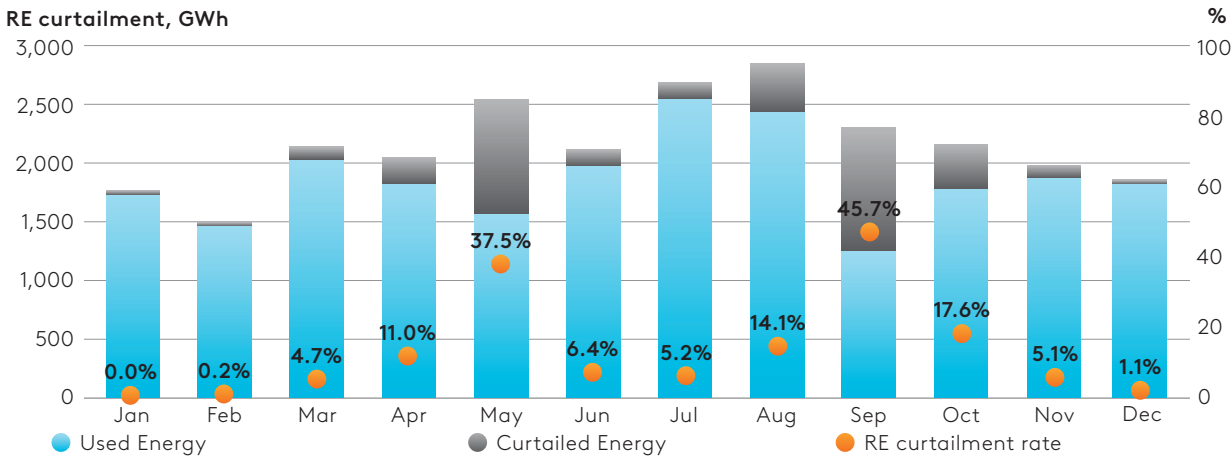
schedule, used to cover peak demand or provide reserves, and compensated through a transparent mechanism. Without such coordination, countries will be forced to duplicate reserves within their national systems, and the capacity utilization factor of new and existing power plants in the region will decline. With coordinated planning, on the other hand, excess capacity is transformed from a local risk of underutilization into a regional resource that enhances reliability and flexibility and reduces the total cost of energy supply.

These cases reveal a recurring systemic pattern. Available capacity in the CAPS is a function of generation, fuel, water, the grid, equipment condition, and operating condition.

Curtailment of RE

The variable nature of RE sources forces many power systems to curtail their output during hours when there is no demand for it and/or when grid stability is compromised. According to estimates ([Silk Road Energy Planning and Engineering, 2025](#)), in Uzbekistan, the commissioning of more than 8 GW of RE will result in a significant surplus during daytime and nighttime hours, and the projected curtailment by 2028 is estimated at 3.5 billion kWh, or 13.6%, requiring wind power generation to be curtailed by 500–800 MW during certain periods. This means that without strengthening interregional and international power flows, increasing flexibility, and developing regional balancing mechanisms, further expansion of RE will be accompanied by increasing system losses.

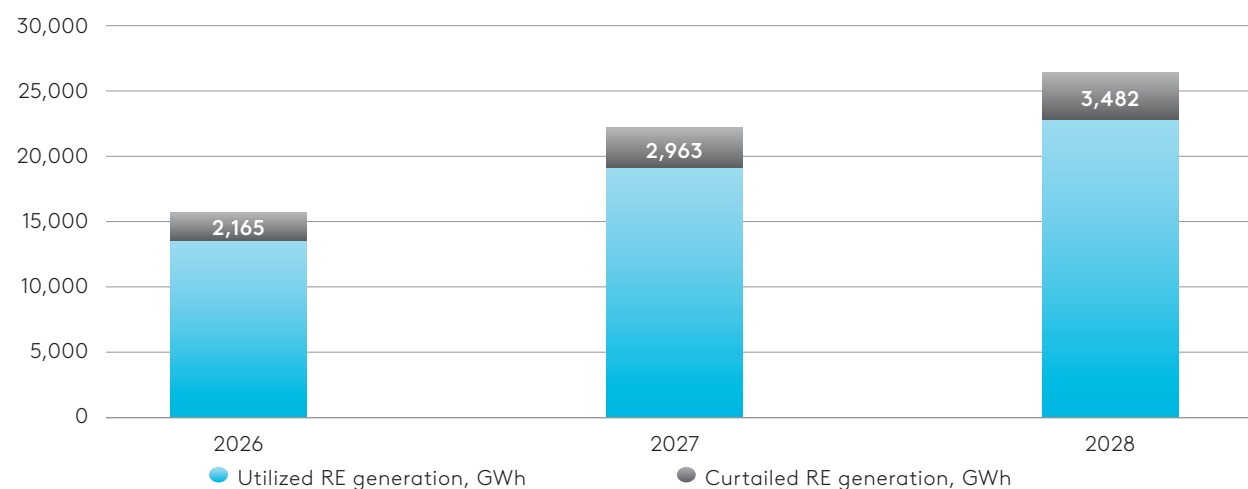
↓ Figure 7. Projected Curtailment of RE in Uzbekistan in 2028, GWh, %



Source: Power System Development Plan for 2026–2028. [Silk Road Energy Planning and Engineering, 2025](#).

According to CDC Energia, citing Uzbekistan’s power system development plan for 2026–2028, energy consumption from renewable sources could reach 13.1 billion kWh in 2026, 18.6 billion kWh in 2027, and 22.2 billion kWh in 2028. Curtailment of RE is projected at 2.2 billion kWh, 3.0 billion kWh, and 3.5 billion kWh, respectively, which is equivalent to 14.2%, 13.8%, and 13.6% of total RE generation.

↓ Figure 8. Forecast of RE Utilization and Curtailment in Uzbekistan, GWh



Source: Silk Road Energy Planning and Engineering, 2025.

These estimates should be considered a lower boundary. They are based on the Uzbekistan Power System Development Plan for 2026–2028 and take into account the trajectory of adding approximately 11.4 GW of RE capacity by 2028. Meanwhile, the national targets for renewable generation development through 2030 significantly exceed this level (25 GW). If the current grid configuration, balancing mechanisms, and cross-border trade regimes remain unchanged, each additional gigawatt of installed RE capacity beyond the projected trajectory may result in at least 0.3 billion kWh of curtailment per year. Accordingly, raising the bar for RE deployment without the accelerated development of grid infrastructure, energy storage systems, and regional balancing mechanisms shifts the projected curtailment volumes upward relative to the values cited. Additionally, it should be noted that the specific intensity of curtailment at high penetration levels of variable generation typically increases nonlinearly; therefore, linear extrapolation also yields a conservative estimate.

Curtailments of RE in Uzbekistan mainly occur between May and October, when RE generation is high and demand is moderate. The highest volume of curtailments is observed in May and September—during periods of transitional demand. Summer load growth due to air conditioning partially reduces curtailment, while in winter curtailment is minimal due to lower RE generation and steady demand for heating.

Curtailment is driven by several factors: the concentration of solar and wind plants in areas with limited local demand and constrained export capability; minimum stable generation levels at conventional plants; limited fast-response reserves; and an underdeveloped short-term balancing framework. The region has already seen cases in which large renewable projects, including the Bash wind farm, increased loading on constrained transmission interfaces and displaced some incoming and transit flows. The storage capacity currently installed is not sufficient to absorb the projected daytime solar surpluses.

According to EDB experts, the economic impact of these curtailments extends beyond lost generation. They affect the economics of RE projects, payments under power purchase agreements (PPAs) and “take-or-pay” obligations, the tariff burden, the payback period for grid projects, and investor confidence. If the system compensates

for curtailed energy, curtailments become a hidden cost of the energy transition. If the investor bears the full risk, the cost of capital rises and the bankability of new projects declines.

To manage this risk, it is important to distinguish between several types of constraints: technical constraints due to stability and security; network constraints due to insufficient transmission capacity; operational constraints due to a lack of reserves and flexibility; and economic constraints related to price, contracts, and risk allocation. For each type, it is important to understand who bears the risk: the investor, the single purchaser, the system operator, the grid owner, or the end consumer.

International experience shows that the growth of solar and wind generation requires timely grid development, flexibility, forecasting, operational rules, and short-term market mechanisms (IEA, 2024). Measures such as grid reinforcement, the development of automatic control systems, monitoring, commercial metering, and flexible generation increase the value of every new megawatt of RE. Regional integration acts as a multiplier here. It expands the demand area, provides access to regulation from hydropower plants, allows for the redistribution of daily surpluses, reduces the need for administrative curtailment of generation, and increases investment predictability for RE projects.

Digital Architecture

The digital architecture of the CAPS is just as essential to integration as physical transmission lines. Without monitoring, automatic control, commercial metering, and secure data exchange, the regional market will be limited to manual coordination and conservative operating limits.

According to CDC Energia, as of 2026 national power systems operate their own Supervisory Control and Data Acquisition (SCADA) platforms and transmit an agreed set of parameters to CDC Energia. The regional digital layer, however, is not yet a fully integrated automated control system. Each country selected or developed its SCADA independently, and the CDC Energia platform was not designed as a full regional supervisory-control system. Selected parameters can be monitored in real time, but the region does not yet have an integrated automated architecture linking national systems, regional coordination, and the future market platform. The current arrangement can support bilateral transactions; a more harmonized digital architecture will be required for a mature day-ahead market, balancing energy, ancillary services, and renewable-energy settlement.

Automatic generation control (AGC) is a core element of coordinated system operation. SCADA supplies real-time frequency, active-power, and interchange measurements, which AGC uses to calculate and issue corrective set-point instructions to generating units. According to CDC Energia, AGC is currently fully operational only within the system of KEGOC JSC. Design and cost-estimate documentation has been prepared for AGC Coordination Center at CDC Energia. In the first phase, the system would cover cross-border interfaces and participating generating units in Uzbekistan, Kyrgyzstan, and Tajikistan, coordinated with Kazakhstan's AGC system.

Wide-area monitoring and control systems (WAMS and WACS) add a layer of enhanced observability and control. WAMS uses synchronized phasor measurement units (PMU) and enables real-time comparison of phase angles at points hundreds of kilometers apart. In the region, WAMS was first installed at KEGOC JSC; at the WAMS control center, it is integrated into SCADA, though currently with a limited set of sensors, primarily covering the North–South transit route in Kazakhstan. KEGOC JSC has already implemented WACS, which has increased the grid’s transmission capacity by recalculating permissible power flows in monitored transmission interfaces in real time; further expansion is planned using forecasting and artificial intelligence.

Another mandatory requirement is a data management policy, since full-scale trading involves the exchange of commercial and sensitive information among many market participants. It defines the list of confidential and commercial data, update frequencies, accuracy requirements, access rights, confidentiality, responsibility for data quality, audit procedures, and rules for using data for market operations, ancillary services, and post-incident analysis. Without such a policy, the digital infrastructure risks remaining merely a collection of technical systems.

Settlement metering is the commercial foundation of the market. CDC Energia has procured and installed a regional settlement metering system, with commissioning, integration with national metering systems, secure data links, and staff training under way. Accurate settlement metering is essential for calculating actual cross-border flows, imbalances, emergency flows, transit volumes, and future day-ahead market transactions.

In early 2026, work began under the REMIT program to establish, launch, and conduct a pilot operation of a regional electricity market in Central Asia. The pilot market will complement long-term bilateral agreements with short-term trading opportunities, and its implementation has been agreed upon at CDC Energia, with a regional market operator to be established under its auspices.

CDC Energia serves a coordinating role and may act as a market platform operator or as a regional coordinator for specific functions. National system operators retain control over their power systems. This architecture allows the market to develop without regional coordination being perceived as a restriction on sovereign authority and makes digital coordination compatible with national responsibility for the reliability of power supply.

Grid Protection and Emergency Control Systems

The growth of cross-border trade, variable RE (VRE), BESS, and more dynamic interchange is changing requirements for protection and emergency control. Much of the existing protection and automation in the CAPS was designed for a system dominated by synchronous generation, relatively stable flow directions, and more predictable fault behavior. The emerging configuration is different: power flows change direction more frequently, generation is more geographically dispersed, a growing share of resources is inverter-based, and critical constraints arise on both cross-border and internal transmission interfaces. Uneven modernization across countries

and delays in integrating new facilities into coordinated protection and control schemes add further complexity.

Relay protection and emergency-control systems affect not only fault clearing but also secure transfer limits. A transmission interface can be operated up to the level at which the system can withstand the loss of a critical element without instability or cascading outages. Modernizing protection and control is therefore one of the more cost-effective ways to increase secure transfer capability. This requires updated network models, verified protection coordination and settings, adaptation to changing flow patterns, and integration with WAMS/WACS and other remedial-action schemes.

Of particular importance is the adaptation of protective systems to the growth of inverter-based resources. Inverter-based sources do not provide a significant level of short-circuit current and require sufficient grid strength to synchronize power electronics; as a result, existing approaches to control and protection must be adapted to the changed characteristics of the generation fleet; at the same time, protection settings at the RE facilities themselves are often set lower than what the equipment allows, leading to unnecessary outages during disturbances ([NERC, 2017](#); [NERC, 2023](#)). International practice provides a ready-made framework of requirements: the IEEE 2800–2022 standard establishes uniform minimum requirements for the connection and performance of inverter-based resources connected to transmission grids, including resilience to voltage and frequency deviations, active and reactive power control, dynamic voltage support, negative-sequence current injection, and system protection requirements ([IEEE, 2022](#)). In the absence of such requirements for dynamic models, fault ride-through capability, and telemetry, the system operator is forced to impose more conservative constraints, which reduces net transmission capacity and increases the risk of curtailment of RE.

The priority for the CAPS is the regional coordination loop for automatic protection and control systems—not the replacement of national protection systems, but the interoperability of their operation at inter-system interfaces, transit corridors, and connection points for large-scale RE sources, BESS, hydropower plants, and potential HVDC interfaces. In the European model, this is enshrined in regulations: the regulation on the operation of transmission systems requires each system operator to coordinate protection settings on cross-border lines with neighboring operators and to coordinate changes to these settings with them (Commission Regulation [EU] 2017/1485). The minimum set of measures for a region includes a joint registry of critical sections and fault effects, agreed-upon N-1 and N-2 calculation scenarios, the exchange of verified dynamic models, joint operator drills, a unified procedure for post-fault analysis, and a mechanism for revising protection settings when major facilities are commissioned. Experience with major system failures confirms that when there is a high proportion of inverter-based resources, protection settings, voltage control, and operator coordination become decisive factors ([ENTSO-E Expert Panel, 2026](#)).

Cybersecurity and Secure Data Exchange

The transition from manual coordination to an automated regional architecture is changing the nature of risk. As long as interaction was limited to coordinating schedules and bilateral deliveries, data transmission failures remained primarily an organizational problem. As the AGC coordination center, WAMS/WACS, regional settlement metering systems, secure communication channels, the settlement platform, and the future electricity and ancillary services market continue to develop, data corruption, tampering, or unavailability are becoming operational and financial risks.

In the regional grid, data is integral to reliability. The assessment of current operating conditions and available transmission capacity depends on the accuracy of telemetry. The correctness of automatic control and emergency response depends on the security of commands and communication channels. The calculation of deviations, emergency energy, ancillary services, and mutual financial obligations depends on the integrity of data from the settlement metering system and the market platform. Therefore, cybersecurity should be viewed not as a secondary IT component, but as a prerequisite for trust in regional trading.

A distinctive feature of the CAPS is that data and control signals cross national borders, while responsibility for protecting the infrastructure remains at the national level. This makes minimum, agreed-upon requirements for the cybersecurity of cross-border interfaces just as much a prerequisite for integration as the calculation of available transmission capacity, commercial metering, or the coordination of emergency response systems. The resilience of the overall digital loop will be determined by its weakest link.

It is advisable to structure requirements on three levels. The technical level should include the separation of the network's technical and corporate segments, secure and redundant communication channels, integrity checks for telemetry and commands, activity logging, data backup, and the ability to switch to local or manual control in the event of a digital circuit failure. The commercial level must ensure the integrity and non-repudiation of AGC data, requests, schedules, deviations, and calculations, since distrust of measurements effectively blocks the ancillary services market and short-term trading. The organizational level must establish access control, the distribution of roles between CDC Energia and national operators, incident notification procedures, data recovery procedures, joint exercises, and requirements for equipment and software suppliers throughout the entire lifecycle.

International best practices provide a ready-made framework for requirements, eliminating the need to develop them from scratch. The IEC 62443 series of standards, originally designed for industrial automation and control systems, has also been adopted by the energy sector because it establishes a methodology for ensuring security in the operational and field environments of cyber-physical systems and covers both organizational and technical aspects throughout the system lifecycle. It is applied in conjunction with the ISO/IEC 27000 series—specifically ISO/IEC 27019 for the energy sector—and with IEC 62351. The IEC 62351 series, in turn, was developed

specifically for the information security of power system control operations and covers various protocols, defining requirements for network and system administration, role-based access control, cryptographic key management, and security event logging (IEC, 2026).

The European Network Code on Cybersecurity, established by Commission Delegated Regulation (EU) 2024/1366, can also serve as a practical guide: it treats cybersecurity not as an internal IT policy for companies, but as part of the rules governing cross-border electricity flows. For Central Asia, this means there is a need for a minimum set of regional regulations: a list of critical digital systems, segmentation of technical and corporate networks, secure and redundant channels, integrity checks for telemetry and commands, access control, logging, incident reporting, joint exercises, and the ability to switch to local or manual control in the event of a digital network failure.

Updating Technical Requirements to Account for RE Sources and BESS

The growth of RE sources and BESS is changing the dynamics of power systems. Solar and wind power plants, as well as battery energy storage systems, are connected via inverters. These can respond quickly to commands, maintain frequency and voltage, and provide ancillary services—provided their behavior is specified in advance in the technical requirements for the connection and operation of facilities, verified during connection, and monitored during operation. The behavior of inverter resources during disturbances is directly related to the operating conditions of protection and emergency-control systems, as discussed above, and must be codified in regulatory requirements.

Thus, the development of new requirements for managing new RE sources and battery energy storage systems is a key prerequisite for the systemic reliability of the CAPS. The higher the share of inverter-based resources, the more critical it is to ensure the quality of dynamic models, telemetry, active and reactive power control, responses to frequency and voltage deviations, and the willingness to participate in ancillary services. This will require amendments to grid codes (which were developed primarily for conventional generation) and their harmonization across countries.

For RE sources, forecasting and telemetry requirements are particularly important. If operators are unable to track actual generation in real time and do not receive a high-quality forecast, they are forced to maintain larger reserves and curtail generation more frequently. In a system with a growing share of RE, this directly increases the cost of reliability.

For a BESS, it is important to distinguish between power and energy capacity. The value in MW indicates how much power the storage system can deliver or draw. The value in MWh indicates how long it can do so. Therefore, a BESS can serve as a fast frequency response resource and, at the same time, as a resource with limited duration for covering the evening peak.

Grid codes should also support market participation. If RE and BESS resources are allowed to provide ancillary services, they should meet measurable requirements for response time, availability, instruction compliance, telemetry, and performance verification. An ancillary services market cannot function without verifiable technical capability and transparent remuneration for delivered services.

International experience with major grid disturbances shows that, when a high proportion of the grid consists of inverter-based resources, voltage control, reactive power control, dynamic fluctuations, protection settings, data exchange, and coordination among system operators become critical. The lessons from such events should be interpreted not as an argument against RE, but as an argument in favor of stricter technical requirements, verified models, enhanced observability, and coordinated post-incident analysis ([ENTSO-E Expert Panel, 2026](#)).

Regional harmonization does not entail replacing national grid codes. In the initial phase, it is sufficient to agree on minimum requirements for cross-border operations, critical infrastructure, RE sources, BESS, HVDC interfaces, data exchange, emergency support, and imbalance settlements. National system operators retain the right to apply stricter requirements within their own power systems. This approach is consistent with the logic outlined by [IRENA \(2026\)](#): regional rules ensure system compatibility, while national codes retain the level of detail and responsibility for internal operations.

Grids, digital control, and reserves determine the actual extent of regional integration. The CAPS is already physically interconnected, but the usefulness of this interconnection is limited by the transmission capacity of the interconnections, internal grid corridors, the availability of fuel and water, the maturity of SCADA/AGC/WAMS/WACS/settlement metering systems, the readiness of protection and emergency-control systems, as well as requirements for new RE sources and BESS.

Deeper regional cooperation is possible only if the requirements for system controllability are raised. First, it is necessary to monitor system conditions, measure power flows, calculate available transmission capacity, control deviations, connect control stations to the regional AGC system, expand the WAMS/WACS, launch the regional settlement metering system, and establish grid codes for RE sources and BESS. After that, a joint “day-ahead” market, a balancing market, and an ancillary services market become technically feasible tools.

This aspect of modernization is particularly valuable. It simultaneously improves reliability, reduces curtailment of RE, supports investment in low-carbon generation, maintains energy affordability, and lays the groundwork for more mature regional trade.

A conceptual image featuring a hand holding a glowing digital network. The hand is positioned in the center, with fingers slightly curled. Overlaid on the hand is a complex network of glowing orange and yellow lines and dots, resembling a star map or a data network. The background is a deep blue with various digital elements: a grid of thin white lines, a series of vertical bars of varying heights in the lower half, and a wavy, translucent blue line at the bottom. The overall aesthetic is futuristic and technological.

5.

THE ECONOMICS OF REGIONAL
COOPERATION AND THE FULL COST
OF RELIABILITY

The economic value of regional cooperation in Central Asia's power sector extends beyond the growth of electricity trade. The volume of kWh remains an important indicator, but the primary benefit lies in reducing the total cost of reliability. This refers to the region's ability to meet peak demand more cost-effectively, utilize existing power plants more efficiently, reduce outage costs, minimize curtailment of RE, enhance the value of hydropower flexibility, and plan investments in grids, reserves, and digital systems more accurately.

The economic challenge is to make this inherited interconnection operationally controllable and capable of delivering measurable system-wide value.

The purpose of this section is to provide a preliminary scenario-based assessment of the economic impact of regional integration. All quantitative estimates in this chapter are preliminary calculations by EDB experts. Data from CDC Energia are used to characterize the initial state of the CAPS, operational constraints, and potential resources. Economic assumptions, including the volume of additional trade, price spreads, the cost of reference capacity, utilization rates, and annual integration costs, were established by EDB experts. The assessment is a system-level screening exercise rather than a chronological production-cost, power-flow, or probabilistic resource-adequacy model. The results therefore indicate the order of magnitude and relative composition of potential effects and should not be interpreted as forecasts of market prices, guaranteed trade volumes, or project-level economic returns. Investment decisions would require project-specific load-flow and stability studies and, where relevant, hourly dispatch and probabilistic adequacy analysis. These screening estimates complement, but do not replace, least-cost regional planning studies such as ADB's CAREC Power Sector Regional Master Plan; the next modeling phase ([Appendix B.7](#)) should be reconciled with them.

Scenario-Based Assessment of the Effects of Integration

The net economic effect was estimated as the sum of four benefit streams minus the annualized integration costs. All results in this chapter are expressed as annual values at steady state, not as cumulative or lifetime amounts; lifetime equivalents are given in [Appendix B.4](#) ([Table 38b](#)):

$$NB_s = B_s^{trade} + B_s^{capacity} + B_s^{curt} + B_s^{reliability} - C_s^{integration}$$

where,

B_s^{trade} — operational savings and trade arbitrage;

$B_s^{capacity}$ — discounted annual avoided or deferred investments in redundant, reliably available capacity;

B_s^{curt} — the value of preserved RE generation;

$B_s^{reliability}$ — reduction in variable costs for emergency support and stress scenarios;

$C_s^{integration}$ — costs of grid, digital, market, and settlement infrastructure.

Three levels of integration are considered. They differ not only in the number of new lines, but also in the quality of management of the existing grid. The three integration scenarios should not be viewed as independent points. The growth in trade, reduction in curtailment, and reduction in redundant reserves in the deeper and advanced scenarios are linked by a common driver—the level of institutional and digital maturity of the system—rather than being the sum of independent improvements. Therefore, the ranges across the effect channels (given in the preceding sections) are correlated with one another: achieving the upper limit in one channel at a given level of integration is highly likely to be accompanied by achieving the upper limit in the other channels as well.

↓ **Table 7. Technical and Operational Assumptions for the Integration Scenarios**

Parameter	Partial integration	Deeper integration	Advanced regional architecture
Estimated increase in equivalent capacity for regional exchanges, GW	0.7–1.2	1.5–2.2	2.2–3.3
Additional trade, billion kWh per year	3.5–6.0	7–11	10.5–16
Total trade, based on 2024 levels, billion kWh per year	15.5–18	19–23	22.5–28
Avoided curtailment of RE, billion kWh per year	0.6–1.2	1.5–2.8	2.8–4.5
Key measures	Improving the utilization of existing grids	Priority network upgrades and launch of a pilot market	Comprehensive network upgrades, DAM, RTM, and ancillary services

Source: EDB expert estimates.

The values are scenario assumptions rather than engineering estimates of ATC or forecasts of electricity trade. They represent plausible ranges associated with progressive improvements in monitoring, operational coordination, grid controllability, and transmission infrastructure. Actual achievable volumes must be confirmed through network and dispatch studies. The additional 3.5–16 billion kWh per year would bring total trade to 15.5–28 billion kWh, above the 1990 level (about 15.1 billion kWh in net terms) in all three scenarios and roughly 1.5–1.9 times that level under the advanced scenario. Volumes of this scale presuppose growth in exportable resources and flexibility across the region, including new hydropower capacity (Rogun and Kambarata-1), additional Turkmen supply, and integrated RE surpluses.

Existing Baseline and Additional Trade

There is no single published indicator of total Available Transfer Capacity (ATC) in the region. It is incorrect to sum the allowable flows of individual monitored transmission interfaces, since many sections belong to the same transmission chain and cannot be utilized at full capacity simultaneously.

Therefore, the equivalent utilized transfer capacity is used for scenario-based assessments. It converts the actual annual volume of regional trade into a notional capacity value, taking into account the duration of grid use and losses. With 12.1 billion kWh traded in 2024, 5,500–6,500 hours of utilization, and losses of about 6%, this equivalent amounts to approximately 2.0–2.3 GW. This metric is used exclusively for calibrating scenarios; it is not a TTC, NTC, or ATC, and does not characterize the physical transmission capacity of a specific line or section. The additional volume was estimated using the following formula:

$$\Delta E_s = \Delta ATC_s \times H_s \times k_s^{use} \times (1 - L_s)$$

where,

ΔATC_s — the increase in effectively available capacity;

H_s — the duration of grid utilization (6,000 hours per year);

k_s^{use} reflects the dispatch-controlled utilization of the available resource;

L_s takes grid losses into account.

The conversion of additional available capacity into trading volume depends on the actual duration and mode of its use. Under the central scenario assumption of approximately 6,000 hours of annual utilization, an 85% dispatch-utilization factor, and transmission losses of about 6%, an additional 1 GW of capacity available for regional exchanges corresponds to approximately 4.8 billion kWh of trading per year. A downside sensitivity, applying lower utilization factors to operating-mode-dependent digital and coordination gains, produces approximately 2.3–3.1 billion kWh per 1 GW. This downside case is not the central assumption used in [Table 7](#); applying it would reduce additional trade, and the trade arbitrage benefit, by roughly 35–50% (see the conservative check in [Appendix B.4](#)). Therefore, the trade volumes presented below should be viewed as scenario-based assumptions rather than direct estimates of additional physical transmission capacity.

The increase in available capacity is achieved in four areas:

- Improved monitoring and control: SCADA/EMS, PMU, WAMS/WACS, condition assessment, automated corrective actions, and more accurate determination of stability limits.
- Operational coordination: AGC, joint maintenance planning, NTC/ATC calculations, reserve coordination, and RE forecasting.
- Local upgrades: substation, transformer, and protection system retrofits; reactive power compensation; reconductoring; and elimination of specific bottlenecks.
- New grid projects: cross-border lines and internal corridors that limit power delivery between the border and load centers.

During the 2024/25 winter operating period, certain monitored transmission interfaces of the CAPS were already operating with minimal stability margins or with power flows exceeding permissible limits. Therefore, the impact of new cross-border transmission

lines will be limited unless internal constraints in Uzbekistan, Kazakhstan, the Fergana power hub, and northern Tajikistan are simultaneously lifted.

Operational Savings and Trade Arbitrage

Operational savings arise when imports replace more expensive generation, emergency startup of inefficient units, fuel constraints, or forced rescheduling:

$$B_s^{trade} = \Delta E_s \times \Delta MC_s^{net}$$

The net spread is the difference between the avoided marginal costs of the importing system and the total delivered cost of the supply, including the exporter's costs, grid losses, and transmission costs. It is not equal to the difference in regulated tariffs. For regional calibration, the results of competitive RE procurements were used: solar PPAs in Uzbekistan were predominantly in the range of about \$22–30/MWh, while the winning bids in Kazakhstan's 2024 auctions were approximately \$20/MWh for a single wind project and \$30–34/MWh for solar projects, based on the average annual exchange rate for 2024. These figures represent long-term contract prices and are used only as reference points for the cost of low-carbon supply; they do not directly determine the assumed trading spread (IFC, 2022; World Bank, 2025; KOREM, 2024a; KOREM, 2024b).

The net spread of \$5–18/MWh applied in the calculations is an EDB scenario assumption representing the difference between the importing system's avoided variable cost and the delivered variable cost of cross-border supply, including losses and transmission costs. The lower bound corresponds to trading during hours of low congestion costs and competitive supply of RE or hydropower; the upper limit applies to hours of fuel constraints, high residual load, and the replacement of more expensive thermal generation.

With corresponding trading volumes, operating savings may fall within the following ranges:

- \$20–110 million per year with partial integration;
- \$35–200 million with deeper integration;
- \$50–290 million with an advanced architecture.

The same spread range is applied to all three scenarios; deeper integration is expected to shift realized spreads toward the upper part of the range, as it provides access to a greater number of peak hours and the ability to replace more expensive generation. At the same time, low-cost RE resources must maintain a price advantage for the buyer: the assessment does not assume that all trading will occur at the cost of emergency power. The actual effect will depend on contract prices, fuel costs, losses, transit fees, and rules for distributing congestion rent.

Reserve Sharing and Avoided or Deferred Capacity Investment

The most significant potential benefit stems not from trade arbitrage, but from reducing each country's need to fully hedge its own peaks, outages, and RE variability within its national borders.

Only cross-border resources that meet the following criteria may be taken into account:

- available during critical hours;
- not simultaneously required by the exporting country;
- deliverable via the grid under the N-1 criterion;
- with a proven contribution to resource adequacy;
- backed by a contractual or market-based commitment.

To assess a reliable contribution, a value significantly lower than the ATC increment is assumed. Depending on the scenario and the degree of peak overlap, it amounts to approximately:

- 0.3–0.7 GW with partial integration;
- 0.7–1.4 GW with deeper integration;
- 1.2–2.2 GW with an advanced architecture.

To estimate the avoided investments, a regional benchmark for the capital intensity of a new CCGT in the range of \$700–\$1,800/kW is used. The lower end of the range is supported by the 1,500-MW Syr Darya CCGT project, with a total cost of about \$1.02 billion, or approximately \$680/kW; the 1,560-MW Surkhandarya CCGT project is estimated at approximately 1.25 billion euros, or about 800 euros/kW ([EBRD, 2020](#); [AIIB, 2025](#)).

A more recent regional benchmark is the contract for the expansion of the Talimarjan Thermal Power Plant (units CC3/CC4, Mitsubishi M701F turbines), signed in November 2022: a cost of approximately \$767–772 million for a capacity of 900–1,065 MW, or roughly \$720–860 per kW. The upper limit of the range (up to \$1,800/kW) accounts for the risk of cost increases for new gas turbine orders amid a global shortage, which intensified in 2023–2025 due to demand from data centers: according to an independent analysis of market contracts ([GridLab et al., 2025](#)), the actual cost of CCGT projects scheduled for commissioning in 2026–2027 exceeds the 2023 model estimates by an average of 20–55%. This range thus reflects not only the capital intensity of the facility itself, but also the risk associated with the timing of equipment orders.

With a discount rate of 8%, a service life of 25 years, and fixed operating costs of about USD 15/kW-year, this corresponds to an annualized fixed cost of approximately USD 80–185/kW-year (a 10% discount rate and a 20-year life would raise the upper bound to about USD 230/kW-year; see [Appendix B.4](#)). Fuel and variable costs are not included to avoid double-counting with operating savings.

The potential savings from preventing or delaying the construction of backup capacity are estimated at:

- \$25–130 million per year with partial integration;
- \$55–250 million with deeper integration;
- \$100–400 million with an advanced architecture.

This category is the largest and, at the same time, the most uncertain. These values represent the potential economic value of avoided or deferred capacity investment rather than a firm capacity credit. Any capacity contribution used for planning or investment decisions would need to be confirmed through probabilistic resource-adequacy analysis (LOLE, EENS, and ELCC), including peak coincidence, hydrology, fuel availability, forced outages, and transmission deliverability.

Reduction in Curtailment of RE

The most detailed curtailment forecast is available for Uzbekistan. With the commissioning of approximately 11.4 GW of RE, curtailment could reach about 3.5 billion kWh, or about 13.6% of potential generation. This corresponds to approximately 0.30 billion kWh of curtailment per 1 GW of installed RE capacity.

For the remaining countries, scenario-based scaling is used, adjusted for the size of the power system, the structure of RE sources, the availability of balancing capacity, grid interconnections, and the expected commissioning of new capacity.

↓ **Table 8. Scenario-Based Screening Estimate of Potential Curtailment of RE by 2030**

Power system	Assumptions for the estimate	Potential curtailment, billion kWh per year
Uzbekistan	Forecast assuming the commissioning of approximately 11.4 GW of RE	3.3–3.6
Kazakhstan	Large-scale deployment of RE, domestic constraints, weaknesses in North–South transmission and at certain interconnection points	1.8–3.0
Tajikistan	Planned deployment of approximately 2 GW of RE, subject to hydropower regulation and grid constraints	0.2–0.4
Kyrgyzstan	Limited but growing deployment of solar PV plants, subject to hydropower flexibility	0.05–0.15
TOTAL		5.4–7.2

Sources: EDB estimate based on data from CDC Energia, national RE development plans, and regional scaling.

Note: With the exception of Uzbekistan, the estimates are regional screening assumptions based on scaling and system characteristics rather than the results of chronological dispatch modeling. They should therefore be interpreted as indicative ranges of potential exposure to curtailment.

Kazakhstan's estimate is lower than the proportional adjustment of Uzbekistan's indicator because the country's power grid is larger and connected to the Unified Energy System of Russia. At the same time, the risk remains significant due to the concentration of RE sources in specific nodes and to limitations on domestic transmission. For Tajikistan, the coefficient is lower due to hydropower plants and reservoirs, but hydropower flexibility is limited by water availability, irrigation releases, the condition of equipment, and grid delivery capacity.

Regional integration can eliminate only that portion of curtailment caused by a lack of demand in a given area, limited interregional transmission, and a shortage of balancing resources. Constraints within a local node prior to connection to the transmission grid require separate grid reinforcement.

The cost of preserved generation is assumed to range from \$15 to \$35 per MWh. The lower bound corresponds to the most competitive results of regional RE auctions, while the upper bound corresponds to solar PPAs and auction results in southern Kazakhstan, taking into account differences in currency indexation, site preparation, and grid conditions. This figure is not a forecast of PPA compensation: it reflects the economic value of useful low-carbon generation that would otherwise be constrained.

Under these assumptions, the potential effect could amount to:

- \$10–40 million per year with partial integration;
- \$25–100 million with deeper integration;
- \$40–160 million with an advanced architecture.

Reliability and Emergency Support Effect

The reliability effect reflects reductions in costs associated with emergency imports, the operation of inefficient units, unplanned rescheduling, fuel switching, and potential shortfalls in power generation.

It is estimated based on the amount of capacity available during peak hours, the duration of such periods, and the cost of emergency coverage. To avoid double-counting, only the variable costs of peak-load operations are included here, not the cost of building reserve capacity. The ranges below correspond to approximately 0.07–0.11, 0.2–0.3, and 0.4–0.5 billion kWh per year of energy supplied through regional support during stress hours, valued at USD 150–350/MWh ([Appendix B, Table 37](#)).

Under these assumptions, the potential effect is estimated to range from:

- \$10–40 million per year with partial integration;
- \$30–100 million with deeper integration;
- \$60–180 million with an advanced architecture.

The width of the range reflects uncertainty regarding the number of stress hours, the availability of external support, the cost of emergency power, and the probability of an actual power shortfall.

Integration Costs

Costs include more than just new cross-border transmission lines. They also include:

- upgrading internal grids and substations;
- digital monitoring and control tools;
- creation of secure communication channels and cybersecurity;
- tools for improved RE forecasting;
- a settlement platform.

In the case of partial integration, the lion's share is accounted for by digitalization, local upgrades, and operational coordination. The deeper integration scenario requires the implementation of priority network projects. The advanced architecture entails a larger investment package, including internal transit corridors and a complete regional control loop.

Based on these assumptions, the annual costs are estimated to range from:

- \$50–100 million for partial integration;
- \$200–350 million for deeper integration;
- \$450–750 million for an advanced architecture.

These figures are portfolio-level annualized scenario assumptions, not current cost estimates for the individual projects identified elsewhere in the report. As an order of magnitude, at a capital recovery factor of about 0.1, these annual costs are consistent with cumulative investment of up to about USD 1 billion, USD 2–3.5 billion, and USD 4.5–7.5 billion, respectively. The ranges should be refined based on current CAPEX estimates for each project, construction timelines, financing costs, and the allocation of costs among countries.

Final Estimate

The ranges of the individual components described above are positively correlated: they tend to rise and fall together. Trade growth, the reduction in curtailment of RE, and the decrease in the need for national reserve requirements depend on the same set of conditions: grid accessibility, digital observability, payment discipline, and the maturity of market rules. Therefore, the gross-effect ranges are the sums of the lower and of the upper bounds, which correspond to consistent low- and high-realization cases. Integration costs, by contrast, are driven mainly by CAPEX, construction timelines, and financing conditions rather than by benefit realization. [Table 9](#) therefore reports the central case (the midpoint of each range) and the favorable case. Combinations that pair low benefits with high costs are stress cases rather than scenario ranges; they are presented in the sensitivity analysis in [Appendix B.4 \(Table 38a\)](#).

↓ **Table 9. Preliminary Scenario-Based Screening Estimate of the Potential Annual System-Wide Economic Effect in the Central Case, millions of dollars per year (annual values, not lifetime)**

Component	Partial integration	Deeper integration	Advanced regional architecture
Operational savings and trade arbitrage	65	118	170
Avoided or deferred capacity investment	78	153	250
Reduction in curtailment of RE	25	63	100
Reliability and emergency support	25	65	120
Gross system effect	193	398	640
Annualized costs	75	275	600
Net effect, central case (midpoint)	118	123	40
Benefit–cost ratio, central case	2.6	1.4	1.1

Source: EDB experts' calculations.

Note: The estimates represent regional system-wide economic effects rather than financial returns to individual countries, utilities, or investors. Payments among regional participants, including transit revenues, ancillary-service payments, and congestion rents, primarily redistribute benefits within the region and are not treated as additional regional economic benefits. Values are annual steady-state flows, not cumulative or lifetime amounts (lifetime equivalents are given in [Appendix B.4, Table 38b](#)). Central values are the midpoints of the component and cost ranges given in the preceding sections and may not sum exactly because of rounding. Sensitivities are presented in [Appendix B.4 \(Table 38a\)](#). The underlying ranges are: gross system effect of 65–320, 145–650, and 250–1,030, and annualized costs of 50–100, 200–350, and 450–750 for the three scenarios, respectively.

The degree of certainty regarding individual components of the effect varies. Operational savings and trading arbitrage can be estimated most directly, as they are based on observed inter-system exchange volumes, price spread ranges, and estimates of additional trading. Estimates of the reduction in curtailment of RE can also be refined with relative reliability as hourly data on generation, curtailment, and grid system operation become available.

Effects related to reliability and the replacement of reserve capacity are characterized by greater uncertainty. The savings from preventing or delaying the construction of backup capacity are potentially one of the largest sources of the regional effect; however, their magnitude depends on what portion of the resources of neighboring power systems can be considered reliably available specifically during peak hours. For investment justification, this effect must be supported by a probabilistic assessment of resource adequacy, using adequacy metrics (LOLE, EENS, ELCC, etc.) and taking into account grid availability, hydrological and fuel constraints, equipment failure rates, and so on. Similarly, the assessment of emergency support depends on the frequency and duration of stress scenarios and the cost of energy shortfalls. Therefore, the estimates shown in [Table 9](#) and in the sensitivity analysis ([Appendix B.4](#)) should be interpreted as a preliminary estimate of the order of magnitude of the potential system-wide effect, rather than as the results of a detailed study for individual investment projects.

Marginal returns diminish as integration deepens. In the central case, partial integration returns about USD 2.6 of annual benefit per USD 1 of annualized cost. The step from partial to deeper integration adds about USD 205 million of annual benefit for about USD 200 million of additional annual cost (a marginal ratio of about 1.0), and the step

from deeper integration to the advanced architecture adds about USD 240 million for USD 325 million (about 0.7). The lowest-cost measures — monitoring, calculation of available transmission capacity, operational coordination, and the removal of the most binding bottlenecks — are implemented first. Later steps require longer lines, internal corridors, and controllable interconnections, while the benefit streams increasingly overlap, because trade, curtailment relief, and capacity savings draw on the same additional transfer capability, and partly saturate, because hydropower flexibility is finite and price spreads narrow as trade grows. This is a three-point scenario comparison rather than a continuous optimum, and it excludes benefits not quantified here, such as optionality for external corridors and domestic reliability gains. It nevertheless supports a sequenced approach: partial integration as the most robust first step, deeper integration selected project by project according to marginal return, and the advanced architecture only where earlier phases demonstrate that utilization and institutional conditions justify it.

The values in [Table 9](#) are annual flows, not cumulative or lifetime amounts. Over a 25-year horizon discounted at 8%, the central case corresponds to a present value of net benefits of about USD 1.3 billion for both partial and deeper integration and about USD 0.4 billion for the advanced architecture. Lifetime equivalents, including their sensitivity to the discount rate and to the gradual build-up of benefits, are presented in [Appendix B.4 \(Table 38b\)](#).

The results allow us to draw several conclusions.

- Positive effects are possible even at the stage of improving the utilization of existing networks. Digitalization, stability management, calculation of net transfer capacity, and coordination of system operation can yield noticeable results even before major network projects are completed.
- The deeper integration scenario combines priority grid upgrades and initial market mechanisms with lower infrastructure costs and institutional complexity than the advanced architecture, and therefore represents an important intermediate case for further technical and economic appraisal. Its central-case net effect is comparable to that of partial integration, but its upside is substantially larger (up to USD 450 million per year). Partial integration has the highest benefit–cost ratio and the smallest downside, which makes it the most robust first step. At the margin, the step from partial to deeper integration roughly pays for itself in the central case (about USD 1.0 of benefit per USD 1 of additional cost), so individual projects should be selected by their marginal return. The deeper package is also less sensitive to rising infrastructure costs and incomplete market liberalization than full-scale optimization.
- An advanced regional architecture generates the greatest overall impact, but its effectiveness depends more heavily on the implementation of all its elements: internal grid reinforcements, digital control, payment discipline, short-term markets, and access to reserves. Building costly infrastructure without removing commercial and operational barriers may result in significantly lower utilization and returns. In the central case its net effect is close to break-even (the step beyond deeper integration returns about USD 0.7 of benefit per USD 1 of additional cost), so it should be pursued as earlier phases demonstrate results.

The regional net effect does not imply that every participating country experiences a positive financial effect under every scenario. The system-wide estimate does not show how benefits are distributed among countries. A quantitative allocation requires the hourly model described in [Appendix B.7](#), but the main channels can already be identified:

- Uzbekistan: about half or more of the avoided curtailment of RE ([Table 8](#)), access to hydropower flexibility for balancing solar generation, and transit revenues for flows from Turkmenistan and to Kyrgyzstan;
- southern Kazakhstan: lower reliability and emergency costs, lower loading of the North–South corridor through better imbalance control, and transit revenues for Russia–Kyrgyzstan flows;
- Kyrgyzstan: remuneration for hydropower flexibility, more reliable winter imports, and reduced pressure on the Toktogul Reservoir;
- Tajikistan: monetization of summer hydropower, reduced non-generating spill, and future remuneration for balancing services from the Vakhsh Cascade;
- Turkmenistan and Afghanistan: export revenues and more reliable supply, respectively, subject to the interconnection arrangements described in [Chapters 8 and 9](#).

Reserve-sharing savings, the largest and most uncertain component, accrue mainly to importing systems, while the costs of flexibility, transit, and grid reinforcement are often borne by other countries. Benefit-sharing and cost-allocation rules ([Chapter 7](#)) are therefore a precondition for moving to the deeper and advanced scenarios. Country-level distribution of benefits and costs, and the corresponding compensation or cost-allocation mechanisms, require separate project-level assessment.

An aerial photograph of a large dam and hydropower plant situated in a deep, mountainous valley. The river flows from the background towards the foreground, where it cascades over a series of smaller dams or spillways, creating white water and mist. The surrounding mountains are rugged and brownish, with some sparse vegetation. The sky is clear and blue.

6.

HYDROPOWER AS A REMUNERATED RESOURCE FOR SYSTEM FLEXIBILITY

A significant portion of the economic benefits of regional integration stems from the flexibility of the systems: reserves, balancing, reducing curtailment of RE, and replacing costly stress modes. The main source of such flexibility in Central Asia at present is hydropower. It helps maintain reliability, reduce the need for expensive peak thermal generation, integrate RE, and lower the carbon intensity of the electricity sector.

According to estimates by CDC Energia and the USAID program (2024), Kyrgyzstan is capable of exporting up to 0.8 billion kWh of balancing energy, and Tajikistan up to 1.02 billion kWh of balancing energy in 2032. These figures reflect the estimated technical potential under the scenario in question and do not imply guaranteed availability of the resource for the regional market. The actual volume will depend on water availability, domestic demand, reservoir operating conditions, the condition of equipment, and grid delivery capacity.

At the same time, water in the region is a multipurpose resource. It is linked to electricity generation, irrigation, ecological flows, food security, and interstate obligations. Hydropower flexibility can be considered a regional service only if it complies with the national energy security of upstream countries, irrigation regimes, environmental flows, and interstate water management obligations.

The international literature on RE integration shows that dispatchable hydropower is valuable not only as an energy source but also as a source of availability, reserves, regulation, and reliably accessible capacity for low-carbon power systems ([Stark and Brinkman, 2023](#)). In Central Asia, an additional dimension is introduced by water constraints: river flow, irrigation priorities, ecological releases, climate change, and interstate water management agreements ([OECD, 2025](#)).

To assess hydropower flexibility, it is advisable to use a scenario-based approach. Calculations should take into account various river flow scenarios, including the P50/P90 approach, irrigation priorities, ecological releases, the internal energy security of upstream countries, and the regulation needs of neighboring power systems. This approach makes it possible to assess not the nominal capacity of a hydropower plant, but the actual flexibility available during a specific season, hour, and water management regime.

Under the “Middle Path” approach, hydropower becomes part of a more complex regional architecture. Its value is realized when three conditions are met: coordinated water and power management regimes, sufficient grid capacity, and transparent payment for flexibility. This approach helps strengthen the reliability of the CAPS, reduce the cost of integrating RE, and ensure that the national interests of both upstream and downstream countries are taken into account.

Naryn-Syr Darya HPP Cascade

The Naryn-Syr Darya Cascade is the central water and power system for Kyrgyzstan, Uzbekistan, and Kazakhstan. It regulates the flow of the Naryn, Karadarya, Chirchik, and Syr Darya rivers along a stretch of approximately 1,000 km from the Toktogul Reservoir to the Chardara Reservoir. The most important reservoirs include the Toktogul, Charvak, Andijan, Kairakkum, and Chardara reservoirs.

↓ Table 10. Key Reservoirs of the Naryn-Syr Darya Cascade

Reservoir	Country/Region	Capacity, billion m ³	Regulation type
Toktogul	Kyrgyzstan	19.5	Multi-year
Charvak	Uzbekistan	2.0	Seasonal
Andijan	Uzbekistan	1.9	Seasonal
Kairakkum	Tajikistan	4.03	Seasonal
Chardara	Kazakhstan	5.7	Seasonal

Source: CDC Energia.

The Toktogul Reservoir has a design total capacity of 19.5 billion m³ and serves the purpose of long-term water regulation. The Toktogul Hydropower Plant, with a capacity of 1,440 MW (after rehabilitation), provides water releases and covers the most critical part of the load schedule. The practical role of Toktogul consists of three tasks: meeting Kyrgyzstan's domestic demand, providing water releases for downstream countries during the growing season, and supplying balancing capacity to the CAPS during peak hours and periods of imbalance. These tasks do not always coincide in time. The irrigation needs of downstream countries are concentrated in the summer, Kyrgyzstan's energy demand is particularly sensitive in the winter, and the region's need for system flexibility grows throughout the year as RE sources are integrated.

Therefore, the use of the Toktogul Reservoir requires a coordinated operating regime, not merely a commercial schedule for electricity sales. The mechanism for developing this regime involves the water management organizations of the participating countries, the Syr Darya Basin Water Organization (BWO Syr Darya), energy agencies, hydrometeorological services, and CDC Energia. Water requirements are coordinated with the Syr Darya Basin Water Organization; then, based on power system data and water flow forecasts, CDC Energia calculates the expected operating regimes for the growing and non-growing seasons. These calculations are used in the preparation of intergovernmental agreements and protocols.

Rising electricity consumption in Kyrgyzstan is putting greater strain on the system. According to data from CDC Energia, annual electricity consumption in Kyrgyzstan rose from 14.6 billion kWh in 2014 to 19.3 billion kWh in 2025. During the non-growing season, consumption increased from 10 to 11.3 billion kWh, and during the growing season, from 4.6 to 6.9 billion kWh. Even the increase in imports from neighboring power grids in recent years has not been sufficient to sustainably restore water levels in the Toktogul Reservoir.

In this context, the Kambarata HPP-1 is a project aimed at ensuring Kyrgyzstan's winter energy security and preserving the regulatory function of the Toktogul Reservoir. The project's regional significance lies in shifting part of the energy load away from Toktogul and strengthening the water-energy balance of the Naryn-Syr Darya Cascade.

The example of the Naryn–Syr Darya Cascade illustrates a complex situation in which long-term energy prospects must be balanced with water management needs, reservoir sustainability, and the national energy security of the upstream countries.

Vakhsh HPP Cascade

While the Naryn–Syr Darya Cascade is closely linked to the water supply of the Syr Darya River, the Vakhsh Cascade is the basis of Tajikistan’s energy supply and an important source of low-carbon electricity during the summer for neighboring countries. Its importance will grow as construction of the Rogun Hydropower Plant is completed.

The main regulatory asset of the Vakhsh Cascade is the Nurek Reservoir. Its total capacity is 10.5 billion m³ (useful capacity: 4.5 billion m³), and it operates on a seasonal basis. During the fall and winter, the Nurek Hydropower Plant operates primarily in power generation mode, meeting Tajikistan’s domestic energy needs and creating conditions for the intake of floodwaters. During the growing season, the Vakhsh Cascade’s operation also takes into account irrigation water needs, but it has its own specific characteristics, since the Nurek Reservoir is subject to seasonal rather than multi-year regulation.

↓ Table 11. Key Facilities of the Vakhsh Cascade

Facility	Parameter	Type of regulation
Nurek Reservoir	10.5 billion m ³	Seasonal regulation
Nurek Hydropower Plant	Tajikistan’s main power generator	Daily/seasonal contribution to the operating regime
Rogun Reservoir	13.3 billion m ³	Multi-year regulation
Rogun Hydropower Plant	Design capacity: 3,780 MW	Upon completion — a major regulating hydroelectric power plant

Source: CDC Energia.

During the period when Tajikistan operated the Nurek Reservoir in isolation, non-generating spills occurred regularly during the summer months. This was because the reservoir receives floodwaters, while the ability to sell electricity to neighboring systems was limited. After trade with Uzbekistan resumed in 2018, the volume of non-generating spills dropped sharply, but it was not possible to avoid them entirely due to capacity constraints in Tajikistan’s domestic 220 kV grids, which prevent the lower stations in the cascade from operating at full capacity.

Tajikistan’s return to parallel operation with the CAPS has increased the regional value of its hydropower. Summer deliveries to Uzbekistan reduce fuel use, lower non-generating spill, and provide flexibility as solar generation expands. The experience of 2024 nevertheless shows that hydropower availability alone is insufficient: its value depends on power deliverability, and some potential generation remained constrained by the domestic transmission network.

The Rogun Hydropower Plant, with a design capacity of 3,780 MW, could alter the operating regime of the entire Vakhsh Cascade. The Rogun Reservoir, with a volume of 13.3 billion m³, is located upstream of Nurek and is classified as a multi-year regulation reservoir. Regulating the flow will reduce non-generating spill into the Nurek Reservoir and allow water releases to be better aligned with commercial electricity generation volumes.

The contractual terms of future deliveries will be of particular importance. A draft trade agreement outlining the basic principles of cooperation with the Rogun Hydropower Plant is already being worked out in the region. Under this agreement, Uzbekistan and Kazakhstan will be able to purchase agreed-upon volumes of electricity, while the Rogun Hydropower Plant will generate these volumes from May through September as the plant's capacity increases. The agreement specifically stipulates that electricity will be supplied primarily during peak demand hours according to an agreed-upon, uneven daily schedule.

This type of output profile enhances the system-wide value of hydropower. The hydropower industry sells not only energy but also the shape of its output profile. Supply during hours of peak demand is more valuable than a steady baseload supply: it reduces the need for peak thermal generation, helps balance RE sources, and improves the reliability of neighboring systems.

In the future market architecture, products related to ensuring the flexibility of power systems—such as peak capacity, secondary and tertiary reserves, and inertia—may play a key role. Tajikistan could become one of the main suppliers of low-carbon flexibility in the CAPS. This role can be realized through grid development, transparent long-term contracts, consideration of hydrological conditions, and compensation for the system value of flexibility.

Flexible Operation of Hydropower Plants

Hydroelectric power plants and pumped-storage hydropower plants (PSHPPs) offer high operational flexibility. They can rapidly adjust their output, cover peak and semi-peak periods of the load curve, serve as emergency and load reserves, participate in frequency regulation, and provide reactive power (subject to hydrological, irrigation, and technical constraints). As RE sources grow, this role becomes increasingly valuable.

Starting a hydroelectric unit from a standstill in turbine mode, with synchronization and a full power ramp-up, takes 1–2 minutes, while starting from idle takes 15–30 seconds. Adjusting the hydroelectric unit's power output or shutting it down takes a few seconds. Therefore, BESS are suitable for very rapid primary response, while hydropower plants are suitable for secondary regulation, peak shaving, emergency support, and seasonal flexibility.

↓ Figure 9. Ancillary Grid Services Provided by Hydropower Plants

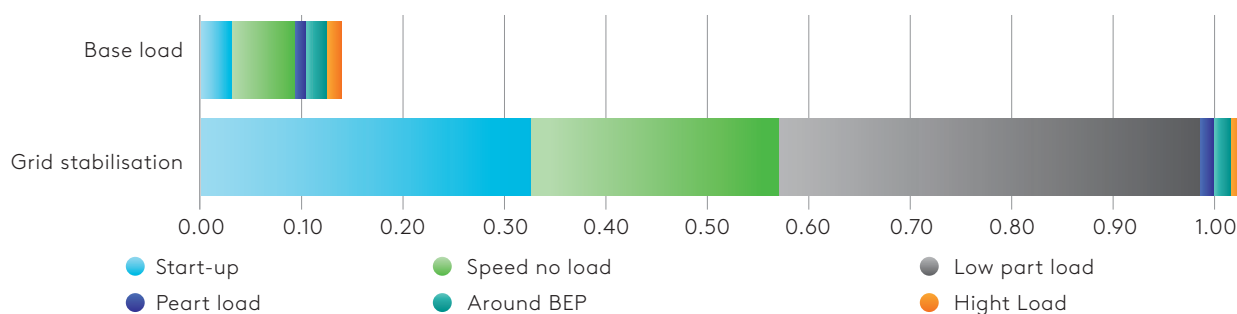
				Hydropower plant type		
				RoR	Reservoir	PSH
Power generation				●	●	●
Balancing			Positive	●	●	●
			Negative	●	●	●
Ancillary	Frequency regulation	Primary	Positive	●	●	●
			Negative	●	●	●
		Secondary	Positive	●	●	●
			Negative	●	●	●
		Tertiary	Positive	●	●	●
			Negative	●	●	●
	Non-frequency regulation	Voltage support		●	●	●
		Active power-loss compensation		●	●	●
		Black start		●	●	●

Source: Adapted from IRENA (2023).

However, operating a hydroelectric power plant in a flexible mode comes at a cost. Frequent starts and stops, operation at partial load, rapid changes in power output, and participation in load regulation increase the operational stress on the equipment. This affects turbines, generators, hydromechanical equipment, control systems, and maintenance cycles. According to an estimate by Seidel et al. (2014), for a Francis turbine, the transition from base-load operation to a grid stabilization scenario reduced the fatigue life by approximately an order of magnitude.

If a hydroelectric power plant is used to provide system flexibility for neighboring power systems, it is important to recognize and compensate for these costs. Hydropower flexibility provides the system not only with kWh, but also with availability, response speed, regulation, a contribution to reserves, and the ability to conserve water for more valuable hours or seasons. Therefore, payment for such a service may take into account the energy actually supplied, availability, operational wear and tear, the opportunity cost of water, lost generation, and water management constraints.

↓ **Figure 10. Relative Wear and Tear of Hydropower Plant Equipment Under Various Operating Conditions**



Source: IRENA (2023).

This approach could help resolve the sensitive issue of the free provision of water resources and regulation by upstream countries. A regional market is sustainable only when the buyer understands what they are paying for—energy, available capacity, response time, and system reliability—and the supplier receives clear compensation.

In current mutual supply arrangements, this value often remains hidden. Whenever possible, the parties utilize the flexibility of Kyrgyzstan’s hydropower plants to ensure that thermal power plants in Uzbekistan and Kazakhstan operate more smoothly. In standard market practice, such regulation services are paid for in accordance with the current “Methodology for Determining Frequency and Active Power Regulation Services,” whereas in mutual supply arrangements, a separate payment for regulation is not typically allocated.

The transition from mutual supply arrangements to a capacity and balancing market does not nullify hydropower agreements; it makes them more transparent. The hydropower sector receives payment for regulation, while recipient countries gain a measurable resource to cover peak demand, reduce curtailment of RE, and provide emergency support.

Energy Storage, Pumped-Storage Hydropower Plants, and Hydropower Plants

Flexibility takes various forms in terms of time horizons and technologies. Rapid initial response, covering the evening peak, daily energy transfer, seasonal water storage, and reserves for years of low water flow require different technologies. Therefore, BESS, hydropower plants, pumped-storage hydropower plants, and reservoir-based hydropower plants perform complementary functions.

BESS are well suited for rapid response. They can deliver or absorb power in milliseconds or seconds, helping to maintain frequency and smooth out short-term dips. Since the metric in MW reflects power and MWh reflects duration of operation, the role of storage systems in covering the evening peak is evaluated based on both parameters.

Hydroelectric power plants are suitable for secondary regulation, peak shaving, and emergency backup. They are faster and more flexible than most thermal power plants; they can adjust their output within seconds or minutes and operate across different parts of the load curve. Their operation is limited by water availability, the tailwater level, environmental permits, equipment condition, and water management agreements.

↓ Table 12. System Flexibility Resources and Their Functions

Resource	Typical function	Time horizon	Key constraint
BESS	Fast frequency response, smoothing of brief dips, local grid support	Milliseconds — hours	Energy capacity in MWh and state of charge
Hydropower plants	Secondary regulation, peaks, emergency reserve	Seconds — hours	Water, tailwater level, reservoir system operation, wear and tear
Pumped-storage hydropower plants	Daily energy transfer, off-peak consumption, and peak-load supply	Hours — days	Capital costs, geography, water, grid
Seasonal regulation reservoirs	Inter-seasonal water and energy transfer	Weeks — season	Irrigation, ecology, water availability forecast
Multi-year regulation reservoirs	Interannual flow regulation	Seasons — years	Low-flow periods and long-term water management rules

Source: Adapted by EDB experts based on CDC Energia.

Pumped-storage hydropower plants are useful for daily energy transfer. They can consume electricity during periods of surplus and supply it during peak hours. This is particularly important in a system with a high share of solar power: the daytime solar surplus can be transferred to the evening peak. Building pumped-storage hydropower plants is capital-intensive and requires suitable topography, water resources, grid infrastructure, and an environmental assessment.

According to an assessment by the Hydroproject Institute commissioned by Uzbekhydroenergo JSC, the potential for pumped-storage hydroelectric power plant construction in Uzbekistan is 5,030 MW.

↓ Table 13. Potential for Pumped-Storage Hydropower Plant Construction by Region in Uzbekistan

Region	Number of potential sites	Total potential, MW
Tashkent Region	8	2,300
Jizzakh Region	3	800
Republic of Karakalpakstan	1	500
Bukhara Region	1	500
Khorezm Region	1	350
Andijan Region	1	330
Kashkadarya Region	1	250
Total	16	5,030

Source: Uzbekhydroenergo JSC.

The greatest potential for pumped-storage hydroelectric power plant (PSHPP) construction is concentrated in the Tashkent region: eight potential sites with a total capacity of 2.3 GW, or 46% of the total estimated potential. Another 0.8 GW is in the Jizzakh region. Collectively, the seven regions comprise a portfolio of 16 potential pumped-storage hydroelectric power plant sites with a total capacity of approximately

5 GW, indicating a significant resource for developing system flexibility, daily balancing, and the integration of RE sources into Uzbekistan’s power grid.

↓ **Table 14. Promising Pumped-Storage Hydroelectric Power Plant Projects Being Developed by Uzbekhydroenergo JSC**

Project	Capacity, MW	Cost, million USD	Generation, million kWh	Useful water volume, million m ³	Implementation period
Verkhnepskenskaya PSHPP	600	1,020	1,050	4.4	2024–2031
Khodzhikent PSHPP	200	320	400	4.4	2024–2029
Karaterenskaya PSHPP	500	477	900	11.0	2024–2030
Aydarkul PSHPP	300	350	450	10.0	2024–2030
Total	1,600	2,167	2,800	29.8	

Source: N. Akhabaev (2024). Prospects for the Development of Pumped-Storage Power Plants in the Republic of Uzbekistan.

Uzbekhydroenergo JSC’s portfolio of PSHPP projects under development includes four facilities with a total capacity of 1.6 GW and a combined estimated cost of approximately \$2.2 billion. The largest project is the 600-MW Verkhnepskenskaya PSHPP in the Tashkent Region. Collectively, these projects could generate up to 2.8 billion kWh of electricity per year and provide a significant resource for daily balancing, energy storage, and the integration of RE sources into Uzbekistan’s power grid.

According to EDB experts, the PSHPP projects under consideration could become part of the system flexibility portfolio; however, their actual value requires confirmation through operational calculations, assessments of round-trip efficiency, grid accessibility, hydrological conditions, and capital costs.

Reservoir-based hydropower plants with seasonal and multi-year regulation perform an important system-wide function. They make it possible to distribute and regulate water resources across seasons and, in some cases, across years. This is particularly important for Central Asia due to the combination of winter electricity demand, summer irrigation needs, dry summers, and the growing share of RE sources.

For Central Asia, a portfolio comprising various sources appears to be the most robust. BESS address rapid and local needs. Hydroelectric power plants in Kyrgyzstan and Tajikistan provide secondary regulation, peak support, and seasonal flexibility. PSHPPs help transfer daytime RE surpluses to the evening hours. Flexible gas-fired units provide reliable, dispatchable capacity during periods of high demand. Well-developed regional interconnections integrate these resources into a single portfolio.

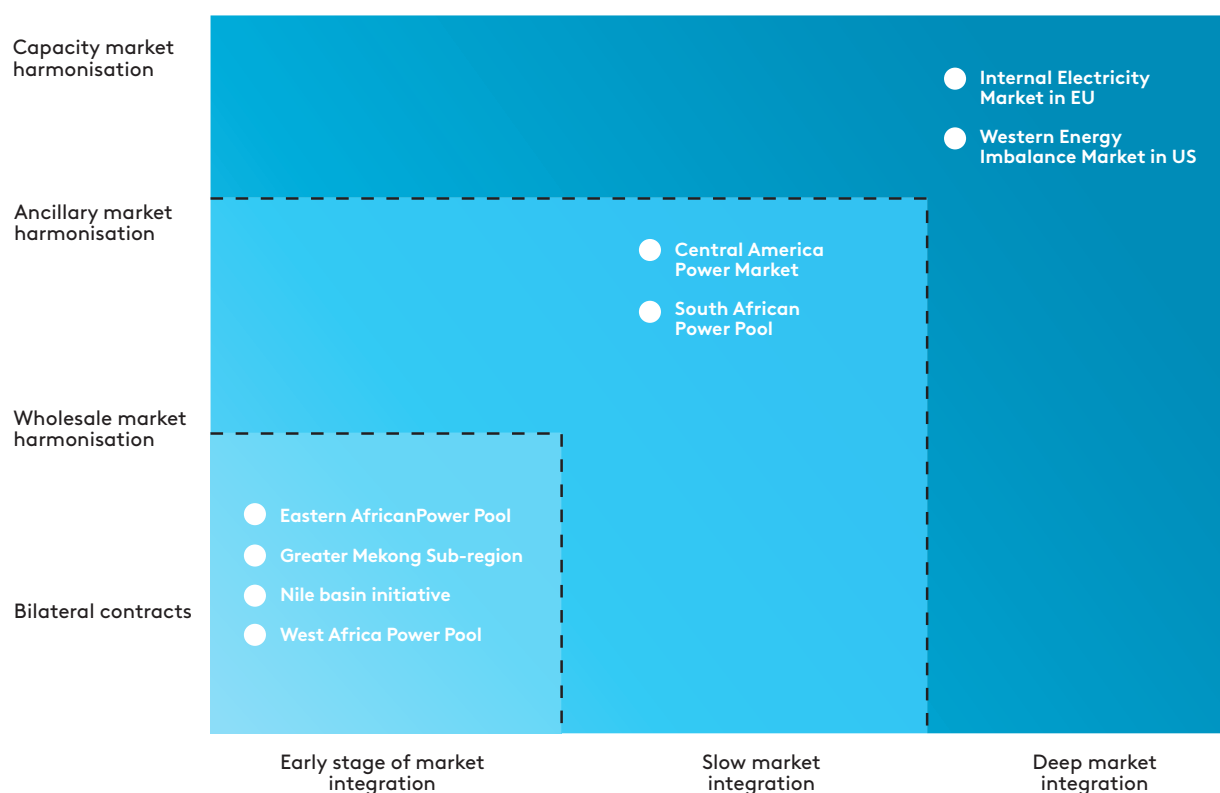
7.

PHASED ARCHITECTURE OF THE REGIONAL ELECTRICITY MARKET

It may be helpful to think of the deepening of regional cooperation in Central Asia's power sector not as a one-time transition to a "common market," but as a phased expansion of functions built upon the existing framework of parallel operation and bilateral trade. As international experience shows (ESMAP, 2025), successful integration is achieved through a combination of "hard" (power lines, transformers, IT systems) and "soft" infrastructure (technical coordination, commercial rules, and institutions), starting with pilot mechanisms and gradually incorporating new participants as the system matures. For Central Asia, this means moving from the task of transforming existing physical interconnections into a more reliable, transparent, and manageable system, toward the gradual formation of a regional market. At the same time, most of the challenges relate specifically to the development of "soft" infrastructure.

The four-stage model is an adaptation of the international logic of phased regional integration. International organizations describe the stages of market development in different ways, but they agree on one thing: integration typically progresses sequentially from bilateral contracts and basic operational coordination to short-term markets, then to balancing and ancillary services, and only then to more complex mechanisms for ensuring long-term resource adequacy. This sequence is particularly important for post-Soviet power systems, where formal market reform without sufficient institutional and operational readiness does not guarantee actual competition and reliability (Mehta, 2007; Skalamera, 2022; IRENA, 2026; ESMAP, 2025; IEA, 2025).

↓ Figure 11. Maturity Levels of Integrated Electricity Markets



Source: IRENA, 2019.

Box 2. International Experience and the Effects of Integration

International experience shows that regional electricity markets rarely emerge immediately as fully fledged single markets. They typically develop in stages: from physical interconnection and emergency support to commercial metering, capacity settlement, short-term trading, balancing, and ancillary services. For Central Asia, the key lesson is that the market usually follows—rather than precedes—technical, institutional, and settlement readiness.

↓ Table 15. International Examples of the Economic Benefits of Integration

Region	Economic Impact	Estimated Impact
Latin America	More efficient use of existing generation capacity and cross-border trade	Up to \$2 billion per year in potential savings by expanding trade without adding new generation capacity
Pan-Arab Electricity Market (PAEM)	Reduction in total system costs through expanded trade and interconnections	\$107–196 billion in aggregate savings from 2018 to 2035; approximately \$35 billion in additional benefits from \$7.5 billion in investment in transmission lines
Southern African Power Pool (SAPP)	Reduced investment and operating costs through coordination	By 2040, a reduction of \$36 billion in CAPEX and \$3 billion in OPEX compared to the sum of national plans
Europe	Reduction in generation costs due to increased transmission capacity and the displacement of more expensive generation	Investments of approximately 2 billion euros per year after 2025 and a reduction in generation costs of up to 5 billion euros per year by 2030.

Source: ESMAP, 2025.

Note: The international estimates provided here apply to markets with varying sizes, income levels, exchange rate regimes, degrees of liberalization, and institutional maturity of regulation. The European market effect arises in a context of well-developed supranational regulation and high liquidity, whereas the effect of the SAPP and a number of other associations reflects a low baseline for cross-system trading. These figures illustrate the possible channels and magnitude of the effect and do not serve as a quantitative benchmark for the CAPS.

The current institutional architecture of the CAPS includes the Coordinating Electric Power Council of Central Asia (CEPC CA), which provides the regional framework for coordinated parallel operation, efficient use of fuel and energy resources, and implementation of intergovernmental agreements and contracts among participating power-sector entities. CDC Energia performs the core technical, dispatch, analytical, and coordination functions and reports to CEPC CA. A pragmatic market architecture can therefore build on a distributed model: national system operators retain responsibility for domestic reliability, CDC Energia provides regional technical coordination and data exchange, and CEPC CA serves as the intergovernmental platform for coordinating rules, operating arrangements, and development priorities.

Since early 2026, work has been underway under the REMIT program to establish, launch, and conduct a pilot operation of a regional electricity market in Central Asia. REMIT can serve as the institutional anchor for the roadmap: the program is designed to facilitate a multi-year, phased transition to a regional market, expand trade, increase transmission capacity, digitize grids, and integrate clean energy. The first phase focuses on Kyrgyzstan, Tajikistan, Uzbekistan, and CDC Energia, which serves as the implementing agency for Components 1 and 3 of the project; within the broader REMIT framework, targets have been set for increasing regional trade, expanding transmission capacity, and creating conditions for the integration of up to 9 GW of clean energy ([World Bank, 2026a](#); [World Bank, 2026c](#)).

↓ **Table 16. Proposal for the Phased Development of the Central Asia Power System Market**

Phase	Objective	Key instruments	Required infrastructure	Expected result
Phase 1	Reliable and transparent bilateral trading	Transaction registry, schedules, settlement metering systems, financial settlements, deviations, emergency support, balancing energy	Settlement metering, secure channels, deviation rules, emergency power protocol	Reduction in unplanned power flows and increased trust
Phase 2	Limited “day-ahead” market on top of bilateral contracts	Pilot “day-ahead” market, ATC/NTC calculation, clearing, payment guarantees	Confirmed transmission capacity, admission rules, settlement discipline	First price signal and utilization of available transmission capacity
Phase 3	Real-time balancing and ancillary services	Real-time market, balancing energy, reserves, frequency control, voltage and reactive power maintenance, ramping capability	AGC, WAMS/WACS, telemetry, grid codes, service performance verification	Flexibility payments and reducing the cost of reliability
Phase 4	Long-term regional resource adequacy	Regional resource adequacy assessment, ELCC, grid deliverability, reliability options, capacity certificates	Capacity adequacy models, resource data, payment discipline, tariff affordability	Coordination of long-term investments and reliability

Sources: EDB experts’ proposals based on materials from CDC Energia, REMIT, and international experience.

The proposed phased architecture is consistent with the evolutionary approach of ESCAP’s Regional Road Map on Power System Connectivity ([ESCAP, 2021](#)), which envisages a transition from bilateral exchanges to multilateral trade and, over time, to more integrated market mechanisms while preserving national competence. For Central Asia, the four levels make this approach more concrete through harmonization of technical and commercial rules, coordination of grid planning and operation, transparent allocation of available transfer capacity, and a gradual transition from bilateral trade to short-term markets, balancing, and ancillary services.

The architecture presented in this chapter is a proposal by EDB experts. It does not reflect a regional market model agreed upon by the countries or an approved reform timeline. The proposals are based on the current technical architecture of the CAPS, materials from CDC Energia, the REMIT project concept, and international experience with the phased development of regional markets.

Overall, the development of a market architecture for Central Asia can be broken down into several stages: first, ensuring reliable data, schedules, settlement metering, deviations, and coordination of emergency support; then, a limited “day-ahead” market; next, real-time balancing and ancillary services; followed by an assessment of regional resource adequacy and more mature long-term reliability tools.

Phase 1 — Refinement of the Existing Base

The first phase builds upon the region’s existing practices. Bilateral contracts, seasonal reciprocal water and energy exchanges, islanded power supplies from Turkmenistan, hydropower imports from Tajikistan and Kyrgyzstan, transit supplies, and emergency support are already part of the CAPS operational practices. Their value will increase if they are accompanied by transparent schedules, verified transmission capacity, commercial metering, and rules for settling deviations.

Bilateral contracts continue to play a central role in the first phase. They are integrated into national models, intergovernmental agreements, water management regimes, and seasonal balances. The market’s role at this stage is to make existing relationships more manageable, measurable, and compatible with future short-term mechanisms.

↓ Table 17. Elements of the First Phase

Element	Function	Expected result
Transaction registry	Registration of participants, volumes, schedules, delivery points, and balance responsibility	Transparency of commercial and dispatch obligations
Settlement metering	Measurement of actual cross-border flows and deviations	Foundation for dispute resolution, payment discipline, and data verification
Settlement of deviations	Comparison of the planned schedule and actual flow	Identification of responsibility for imbalances
Emergency power	Separate accounting for emergency support outside of standard commercial imbalances	Maintaining operational safety under stress conditions
Balancing energy	Inter-operator exchange of regulating energy	Reducing the cost of covering deficits and replenishing reserves
Improved visibility for RE projects	Telemetry and basic forecasting for large-scale RE facilities	Improving system control as inverter-based generation grows

Sources: EDB expert recommendations based on materials from CDC Energia, REMIT, and international experience.

Each cross-border transaction should be accompanied by a minimum set of data: participants, volume, direction, delivery period, hourly or daily schedule, delivery

and withdrawal points, transmission capacity used, the party responsible for balancing, the procedure for settling imbalances, and the applicable emergency support protocol. Such a transaction registry will allow system operators to see in advance which commercial flows overlap with the network's technical constraints.

Commercial metering is the foundation of this stage. Without a reliable settlement metering system, it is impossible to accurately calculate actual power flows, deviations, emergency power, transit, and settlements between parties. CDC Energia notes that the regional settlement metering system has already been purchased and installed; commissioning work, integration with national settlement metering systems, the creation of secure data transmission channels, and staff training are currently underway.

Resolving imbalances is one of the first and most important conditions for market development. Under the current system, uncompensated imbalances can place a burden on already overloaded transit routes—including the North–South corridor in Kazakhstan—and create system-wide risks. In the first stage, it is important to define what constitutes an imbalance, how it is measured, who is responsible, at what price it is compensated, how emergency power is accounted for, and how transit countries are taken into account.

Emergency support can be formalized as a standard operating procedure. In the CAPS, where a number of sections operate with minimal stability margins, emergency mutual assistance should not depend solely on manual decisions made at the moment of a crisis. The protocol specifies who declares an emergency mode, who confirms available resources, what volume can be transferred without threatening the neighboring system, how energy is recorded, and how it is paid for.

At the initial stage, balancing energy may remain an inter-operator product. This is not yet a fully competitive balancing market. However, even at this stage, countries that lack their own balancing resources may be able to obtain balancing energy from their neighbors in the event of a shortage, a schedule disruption, or the need to replenish reserves. Of particular importance are the hydropower plants in Kyrgyzstan and Tajikistan, Uzbekistan's flexible gas-fired units, the potential role of Turkmenistan, and future BESS projects.

By the end of the first phase, the region will not have a market in the full sense of the word, but rather a managed operational and commercial framework. This is consistent with the engineering logic of the CAPS: first, reliable data, schedules, metering, deviations, and emergency support; then, more complex market products.

Phase 2 — The “Day-Ahead” Market (DAM)

The “day-ahead” market could become the first fully fledged market product of regional integration. Its purpose is to utilize available inter-system transmission capacity after accounting for priority bilateral contracts and seasonal agreements. This approach preserves the existing trading framework while simultaneously creating the first transparent price signal.

↓ Table 18. Key Parameters of the “Day-Ahead” Pilot Market

Category	Technical Definition	Role in the “day-ahead” market
TTC	Total transfer capacity under the design operating conditions	Upper technical limit of cross-flow
TRM	Transmission reliability margin	Accounting for operational uncertainty and emergency conditions
NTC	Net transfer capacity, TTC minus TRM	Potential commercial transmission capacity
Committed schedules	Bilateral contracts, seasonal exchanges, transit obligations	Priority commitments prior to allocation of ATC
ATC	Available transfer capacity after accounting for committed schedules	Transmission capacity for DAM

Sources: EDB experts’ proposals based on materials from CDC Energia, REMIT, and international experience.

It is important for a pilot market to have a simple and transparent structure. In the initial phase, a zonal pricing model or allocation by transmission interface is possible without transitioning to a complex nodal model. Participants’ bids include volume, price, delivery period, direction, and confirmation of readiness for settlement. Clearing—the matching of bids and determination of auction results—is performed only within available capacity and after verification of system reliability.

International experience shows that short-term markets work best as a tool for effective dispatch and price signaling, whereas investment and risk management functions require additional long-term mechanisms (IEA, 2025). Therefore, the “day-ahead” market in the CAPS should be launched as a limited, voluntary pilot segment tied to confirmed transmission capacity, in addition to existing bilateral contracts.

The key issue in the “day-ahead” market is available transmission capacity. The existence of a physical line does not imply the availability of commercially available capacity for a transaction; therefore, one should work only with the amount of transmission capacity that has been calculated and confirmed in accordance with the TTC/TRM/NTC/ATC methodology.

Payment guarantees are a key prerequisite for the maturity of the “day-ahead” market. Guarantees, escrow accounts, letters of credit, netting, and a default coverage fund reduce the risk of settlement failure. For international financial institutions and private investors, the existence of such an architecture demonstrates that the market possesses technical and financial discipline.

It is important for transit countries to formalize fees for transit and grid use. If electricity is transmitted through a third country’s grid, it occupies transmission capacity, causes losses, and may require rescheduling. The transmission tariff should be simple for the pilot project, but transparent and predictable. In a more mature model, it may take into account direction, voltage level, losses, line utilization, and the investment component. International practice in regional trade shows that pricing for transmission and the allocation of grid costs are central to building trust among participants and ensuring the bankability of projects (World Bank/ESMAP, 2026).

↓ Table 19. Elements of the “Day-Ahead” Pilot Market

Element	Description	Market Significance
Participants	Eligible generators, buyers, traders, or consolidated buyers from participating countries	Credit and operational risk mitigation
Product	Hourly or block energy for the following day	Simplified initial trading model
Transmission capacity	ATC confirmed after accounting for bilateral contracts	Market compatibility with operational constraints
Clearing	Regional platform based on CDC Energia/ market platform operator	Unified order-matching algorithm
Financial settlements	Legally binding settlements with payment guarantees	Reduced risk of non-payments and settlement disputes
Transit	Transit and network usage fees	Compensation for the transit country’s network resources
Market monitoring	Monitoring of market concentration, market power, and bid manipulation	Confidence in auction results and price signals

Sources: EDB expert projections based on data from CDC Energia, REMIT, IEA (2025), and ESMAP (2026).

The “day-ahead” pilot market has three effects. It reveals actual price differences between systems; it shows where transmission capacity is most valuable; and it creates a practical foundation for future balancing, because participants begin to plan their deliveries not only based on long-term contracts, but also on short-term economic signals.

In this implementation, the “day-ahead” market operates on top of existing bilateral contracts, within the limits of confirmed transmission capacity, and only if the settlement discipline stipulated in the first phase is observed.

Phase 3 — Real-Time Balancing and Ancillary Services

Phase 3 shifts the focus of integration from trading scheduled electricity to trading in balancing energy. This is particularly important for Central Asia due to the growth of RE, limited reserves, fuel risks, hydrological seasonality, and congested transmission sections.

Real-time balancing closes the gap between the plan and actual results. The “day-ahead” market schedules deliveries for the following day; however, actual RE generation, load, outages, and grid constraints may differ from the forecast. The real-time market, or real-time balancing mechanism, allows for payment of actual adjustments and creates incentives for resources that help the system in the moment.

Ancillary services are structured as separate products. In current practice, some of these services are already being provided: frequency and balancing services

from hydropower plants in Kyrgyzstan and Tajikistan, emergency support, transit, and maintenance of operating conditions. Defining them as market products makes flexibility measurable and payable.

AGC is the core control technology for this phase. According to CDC Energia, a fully operational AGC system is already in place within KEGOC JSC, and design and cost-estimate documentation has been prepared for a regional AGC Coordination Center at CDC Energia. The configuration proposed in this report would connect participating generating units across the CAPS and therefore requires both technical and institutional coordination.

WAMS/WACS are also becoming part of the flexibility market. WAMS improves observability, while WACS can increase available transmission capacity through wide-area control. According to CDC Energia, the use of WACS in the KEGOC grid has made it possible to increase allowable power flows on certain monitored transmission interfaces significantly.

↓ Table 20. Key Ancillary Services Products

Product Name	Service
Primary frequency response	Fast frequency deviation response
Secondary control / Automatic frequency control	Restoration of frequency and scheduled interchange
Tertiary reserve	Balance restoration reserve
Balancing energy	Actual energy to close the imbalance
Voltage and reactive power maintenance	Voltage and reactive power maintenance at critical nodes
Rapid power change and emergency support	Rapid power ramp-up/ramp-down and emergency assistance

Source: Adapted by EDB experts based on CDC Energia materials.

For RE sources and BESS, participation in ancillary services is governed by grid codes. New facilities must transmit data from telemetry, forecasts, and dynamic models; provide reactive power; and maintain operational capability within permissible frequency and voltage deviations. This integration reduces the risk of erratic behavior in inverter-based generation and makes RE sources a component of system stability.

The third phase is particularly important for hydropower. Hydropower plants in Kyrgyzstan and Tajikistan can provide secondary regulation, peak power, rapid power adjustment, emergency support, and seasonal balancing. Payment for these services should take into account availability, response time, operational wear and tear, the opportunity cost of water, and water management constraints.

The ancillary services market is a key element in the integration of RE and hydropower flexibility. It allows for payment not only for kWh, but also for availability, response speed, frequency regulation, voltage maintenance, reserve capacity, and emergency support.

Phase 4 — Regional Resource Adequacy Assessment and Reliability Instruments

The fourth stage addresses long-term resource adequacy. For the CAPS, the more robust sequence is to begin with a regional probabilistic resource adequacy assessment, then recognize dependable cross-border resource contributions, introduce reliability options or other transitional instruments where appropriate, and only later consider a comprehensive capacity mechanism.

The capacity market is a complex tool. In a region with regulated rates, vertically integrated structures, price sensitivity among the public, and varying levels of payment discipline, it can quickly become an opaque mechanism for supporting existing generation capacity. Therefore, it is advisable to first demonstrate the need for long-term reliability, then identify the resource that truly reduces the risk of shortages, and only then introduce a payment mechanism.

At this stage, a regional assessment of resource adequacy becomes crucial. It answers the question: Does the region have sufficient reliable resources to meet demand, taking into account outages, low water levels, fuel availability, the growth of RE, seasonality, grid constraints, and external power flows? Such an assessment should be probabilistic, not merely based on a supply–demand balance.

A consistent reliability vocabulary is essential. LOLE (Loss of Load Expectation) measures the expected frequency or duration of periods in which available resources are insufficient to meet demand. EENS (Expected Energy Not Served) measures the expected volume of unserved energy. ELCC (Effective Load Carrying Capability) measures the contribution of a resource to resource adequacy. Grid deliverability captures whether that resource can physically reach the relevant load area, while reliability of power import refers to the cross-border contribution that can be relied upon during critical hours.

The second step is recognizing cross-border capacity contributions. For example, hydropower plants in Tajikistan may make a significant contribution during summer and evening operating conditions, but this contribution must be confirmed through grid deliverability, water release schedules, and contractual agreements. Turkmenistan’s generating capacity can be a valuable external resource, but its availability to the CAPS is currently limited by islanded operation and synchronization issues. BESS can provide rapid reserve capacity, but its contribution depends on its energy capacity (storage duration). RE sources contribute to resource adequacy, but this contribution must be accounted for through ELCC.

The third step involves more flexible reliability mechanisms. A comprehensive capacity mechanism is considered a long-term tool. Interim solutions may include capacity certificates, reliability options, a strategic reserve, reliable import contracts, and agreements on the shared use of reserves. These allow for the formalization of reliability until a mature capacity market emerges.

↓ Table 21. Sequence of Long-Term Reliability Instruments

Instrument	Function	Conditions for application
Regional resource adequacy assessment	Assessment of the risk of shortages based on LOLE, EENS, and capacity reserve	High-quality data on demand, generation, RE, water, fuel, and grids
Cross-border capacity contribution	Recognition of reliable cross-border resource contributions	ELCC, grid deliverability, and ATC certification
Capacity certificates	Confirmation of resource availability	Resource certification and verification
Reliability options	Standby fee with shortfall liability	Financial settlements, credit protection, and activation rules
Strategic reserve/resource sharing	Limited reserve and resource sharing	Agreements between NSOs and verified availability
Capacity mechanism	System-wide payment for long-term reliability	Mature market, tariff affordability, and payment discipline

Sources: Proposals by EDB experts based on [IEA \(2025\)](#).

Tariff affordability is particularly important for Central Asia. Capacity mechanisms create new charges. If they are introduced without explanation, without sharing the benefits, and without a link to reliability, they may increase pressure on tariffs. Therefore, every reliability mechanism must demonstrate: what risk it mitigates, what resource it pays for, why it is cheaper than the alternative, and who benefits.

Long-term resource adequacy must support reliability without causing excessive cost increases. Therefore, the capacity mechanism is a potential final tool, not a starting point.

Responsibilities of the Regional Coordinator and National Operators

The institutional architecture of the regional market requires a politically sensitive allocation of functions. National system operators (NSOs) retain responsibility for internal system operation, reliability, grid access, operational teams, and national balancing. Regional coordination reinforces this work through shared data, calculations, and rules.

In addition to its regional system-operator role, CDC Energia could perform regional coordination, market-platform, and settlement-coordination functions. National system operators would retain sovereign control over domestic dispatch and system security.

To build trust among participants, a set of specified rules is required to formalize each stage of trading and physical operations. These elements form the institutional foundation for the transition from coordinated bilateral transactions to a more mature form of partial integration.

↓ Table 22. Distribution of Functions in the Regional Architecture

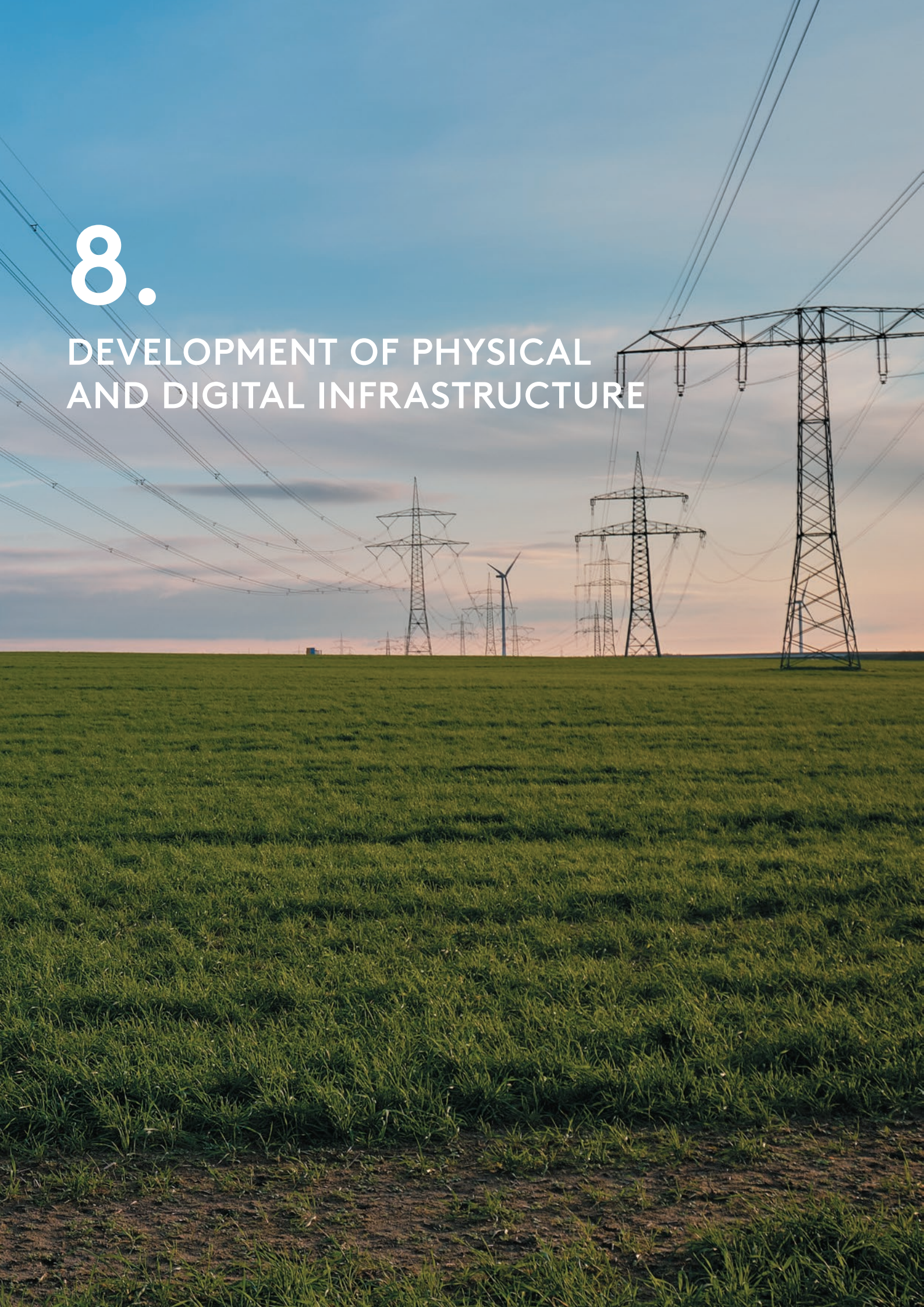
Institution	Possible functions	Principle to be preserved
CDC Energia/Regional Coordinator	Coordination of system operation, calculation of cross-border schedules, AGC Coordination Center, market platform, coordination of financial settlements, data center	Support for national dispatch control
National system operators (NSOs)	Internal operating condition, reliability, grid access, balancing, dispatch instructions	Oversight of the safety of national power systems
National regulators	Tariffs, grid access, licensing, consumer protection	National regulatory responsibility
Market platform operator	Order acceptance, clearing for the “day-ahead” and real-time markets, and publication of results	Transparent operational function free from political interference
Settlement coordinator	Settlements for transactions, deviations, emergency power, and ancillary services	Financial discipline and payment protection
Market monitoring and dispute resolution function	Monitoring of market power and manipulation, and dispute resolution	Participant confidence and reduced risk of politicization of settlements

Sources: Proposals by EDB experts based on data from CDC Energia, the [World Bank \(2026a\)](#), [ESMAP \(2026\)](#), and the REMIT framework.

An important aspect of institutional design is monitoring market transparency. The region has large state-owned and vertically integrated market participants, and certain market segments may be undersupplied. Therefore, even a pilot “day-ahead” market must include monitoring of market concentration, rules of conduct, withholding of generation or transmission capacity, bid manipulation, and abuse of transit status.

To build participant confidence, market-power monitoring and dispute resolution should be institutionally and functionally separate from the regional coordinator, market-platform operator, and settlement coordinator. Possible models include a dedicated oversight function under CEPC CA, an independent market monitor, or coordinated oversight by national regulators under a common regional framework. At the initial stage, the function can remain compact, but it should have access to relevant data, authority to request explanations, and the ability to publish aggregated findings.

Data quality and transparency are of great importance. Market participants and investors need access to information on available transmission capacity, line utilization, rules for curtailment of RE, imbalance prices, day-ahead market results, volumes of ancillary services, and emergency support statistics. Some of this data may be published in aggregated form to avoid disclosing commercially sensitive information.

A landscape photograph featuring a lush green field in the foreground. In the middle ground, several high-voltage power line towers are visible, with power lines stretching across the sky. A single wind turbine stands out among the power lines in the distance. The sky is a clear, pale blue, suggesting a bright day.

8.

DEVELOPMENT OF PHYSICAL AND DIGITAL INFRASTRUCTURE

Regional integration of the CAPS requires two interrelated types of infrastructure. The first layer is physical infrastructure: power lines, substations, transformers, DC links, and protection and emergency-control systems. The second layer consists of “soft” (digital and market-based) infrastructure, as discussed earlier.

These two layers should be viewed as a single investment portfolio. A new line achieves maximum effectiveness when combined with telemetry, transfer-capacity calculations, deviation rules, and commercial metering. A digital system enhances the utility of the existing network, but does not replace the need to reinforce overloaded sections. Therefore, it is advisable to evaluate each project using the following framework: constraint — technical solution — systemic effect — dependency — monitoring indicator.

The development of cross-border connections has already been discussed at the level of the energy ministries of Kazakhstan, Kyrgyzstan, and Uzbekistan; a working group under the CEPC CA has prepared options for strengthening key interfaces. These options cover the routes Turkmenistan–Uzbekistan, Uzbekistan–Kazakhstan, Kazakhstan–Kyrgyzstan, Uzbekistan–Kyrgyzstan, Uzbekistan–Tajikistan, and the North–South transit route through Kazakhstan.

International experience shows that regional electricity integration requires the simultaneous development of interconnection infrastructure, coordinated planning, operational coordination, commercial mechanisms, and institutional architecture (ESMAP, 2025). For Central Asia, this means that the investment portfolio should not be a list of transmission lines, but rather a program to address specific system constraints.

The list of projects was compiled based on data from CDC Energia, national system operators, and other relevant sources. The project status reflects the information from the corresponding primary source. Categories P1, P2, and P3, the description of the system-wide impact, and the proposed KPIs represent the EDB’s expert prioritization and do not imply an approved funding sequence or intergovernmental approval of the projects.

It is advisable to prioritize projects according to the rule “one constraint—one system-wide effect—one project or package of projects.” Priority P1 may include solutions that already have institutional ties, can quickly improve controllability or remove a critical constraint, and support the initial stages of REMIT: metering, deviations, emergency support, the “day-ahead” market, and basic settlement discipline. Priority P2 includes projects with a high system-wide impact that require additional coordination with neighboring grid solutions, feasibility studies, financing, or operational arrangements. P3 consists of strategic options that are important for long-term architecture, external connections, and the managed connectivity of power systems, but require separate technical, financial, and interstate analysis.

↓ Table 23. Indicative Prioritization of Grid Projects

Priority	Project/Package	Main function and system-wide impact	Status/KPI
P1	Kristall–Yulduz, reconstruction and second 220 kV circuit	Uzbekistan–Kyrgyzstan, Fergana power hub; increased transmission capacity and reliability of the interconnection	Planned for Phase 1 of REMIT; indicator: increase in ATC, reduction in Kr-Y constraints
P1	(Option 1) Second 500 kV transmission line Shymkent–Tashkent TPP	Uzbekistan–Kazakhstan; strengthening of the existing interconnection and support for trade with southern Kazakhstan	Included in Phase 2 of REMIT; indicator: reduction in congestion on L-501/L-2-Ch/L-2-D
P1	(Option 2) 500 kV Shymkent–Khalka Substation transmission line	Uzbekistan–Kazakhstan; alternative to the 500 kV Shymkent–Tashkent TPP transmission line	Alternative project proposed by the Ministry of Energy of Uzbekistan
P1	AGC Coordination Center + settlement metering + secure channels	Control of net flows, financial settlements, balancing, and foundation for the REMIT pilot	Design, installation, and commissioning based at CDC Energia; metric: reduction in deviations, coverage of metering points
P1	Frunze–Kemin/Bishkek-500	Kyrgyzstan’s internal reliability and stability of hydropower output	Planned for Phase 3 of REMIT; indicator: reduction in internal grid constraints
P2	Kemin–Almaty	Kazakhstan–Kyrgyzstan; support for seasonal mutual supply and hydropower flexibility	Proposal by CDC Energia; indicator: relief of L-514, increase in ATC
P2	Datka–Sughd in transit mode + tie-in at Lochin Substation/Uzbekistan Substation	Fergana power hub, CASA-1000, northern Tajikistan; increasing the transfer limit	Proposal by CDC Energia; indicator: increase in transmission to the Fergana power hub
P2	Syr Darya/ACWA–Sughd	Uzbekistan–Tajikistan; reliability of the Sughd Region and connection to Uzbekistan	Based on CDC Energia, funded by the ADB; indicator: reduction of constraints in northern Tajikistan
P2	Muruntau–Shymkent	Uzbekistan–Kazakhstan, southwestern Uzbekistan; rerouting of flows to the Shymkent power hub	Proposal by the Research and Development Center and JSC NES of Uzbekistan; indicator: relief of congestion in southwestern sections
P3	Atamyrat–Guzar	Turkmenistan–Uzbekistan/CAPS; increased output of Turkmen capacity	Option in the event of parallel operation with Turkmenistan; indicator: increase in available thermal capacity
P3	Dashoguz–Muruntau–Kyzylorda	Turkmenistan–Kazakhstan via Uzbekistan; power supply to southern Kazakhstan	KEGOC proposal; indicator: bypassing some Uzbek bottlenecks and supporting southern Kazakhstan
P3	Back-to-back HVDC (B2B) at the border between the CAPS and the Unified Energy System of Kazakhstan	Controlled northern interface; reduction of uncontrolled power flows from north to south in Kazakhstan	Subject of a separate feasibility study; indicator: controllability of power exchange and reduction of emergency risks

Sources: Compilation by EDB experts based on CDC Energia and REMIT.

Several criteria should be used to select projects: increased transmission capacity, reduced curtailment of RE, reduced risk of outages, improved monitoring capabilities, readiness for financial analysis, and a realistic path toward a feasibility study, environmental and social assessments, and financing. These indicators link investments to measurable system-wide effects and enhance the bankability of projects for international financial institutions.

Uzbekistan — Kazakhstan

The Uzbekistan–Kazakhstan interconnection is one of the key corridors for regional trade. It connects the CAPS’s largest power grid to southern Kazakhstan, where the reliability of supply depends on the status of North–South transit within Kazakhstan and external power flows.

The main constraint in this direction is related to the transmission capacity of the L-501, L-2-Ch, and L-2-D transmission lines. The primary solution under consideration is the construction of a second 500 kV transmission line between the Shymkent Substation and Tashkent TPP. This project is already included in the second phase of REMIT, which enhances its institutional readiness and significance for the pilot architecture of the regional market. The project is expected to improve the stability of the Uzbekistan–Kazakhstan interconnection, expand available transmission capacity, and reduce the risk of congestion in trade between Uzbekistan and southern Kazakhstan.

At the same time, it is important to note that, based on a proposal from the Ministry of Energy of the Republic of Uzbekistan, the 500 kV transmission line from the Khalka substation to the Shymkent Substation should be considered the preferred option for the second phase of REMIT, rather than the aforementioned route from the Tashkent Thermal Power Plant to the Shymkent Substation. This configuration takes into account the limitations on expanding the 500 kV switchyard at the Tashkent Thermal Power Plant and the expected concentration of power flows toward the Khalka substation.

A complementary solution is the 500 kV overhead line between the Muruntau substation and the Shymkent Substation. This proposal by the State Institution “Research and Development Center” and JSC NES of Uzbekistan involves feeding power from the surplus-energy region of Uzbekistan directly into the Shymkent power hub, which is experiencing a power shortage. Calculations show that such a scheme could relieve congestion in problematic sections of the southwestern part of Uzbekistan’s power system and mitigate the problem of Turkmen power being locked out of the CAPS.

These two projects can be compared in a single techno-economic analysis. The second power line, Tashkent TPP–Shymkent Substation, reinforces the existing interconnection. The Muruntau–Shymkent line can reroute power flows and have a broader impact on Uzbekistan’s internal grids, including the delivery of power from Turkmenistan and the alleviation of constraints in the southwest. When determining priorities, it is important to consider not only capital costs but also the increase in transmission capacity, the impact on curtailment of RE, support for southern Kazakhstan, the reduction of accident risk, and readiness for financing.

Kazakhstan — Kyrgyzstan

The Kazakhstan–Kyrgyzstan interface is important for seasonal water and energy exchanges, the reliability of southern Kazakhstan, and the utilization of Kyrgyzstan’s hydropower flexibility. Its limitations are directly linked to Kyrgyzstan’s role as a provider of regulation and to the sensitivity of southern Kazakhstan to cross-border flows.

There are two related tasks in this area: relieving the load on L-514 and strengthening the internal connection between the Frunze Substation and the Kemin Substation. To relieve the overload on L-514, it is proposed to consider the construction of a 500 kV transmission line between the Kemin Substation and the Almaty Substation. To strengthen Kyrgyzstan’s internal connectivity, it is proposed to accelerate the construction of the 500 kV transmission line between the Frunze and Kemin substations, with a subsequent connection to the future Bishkek-500 Substation. The project is included in the third phase of REMIT; to accelerate its implementation, it is proposed to divide the Frunze–Bishkek–Kemin transit route into two sections.

The 500 kV Kemin–Almaty transmission line primarily addresses an interstate issue. It strengthens the connection between Kyrgyzstan and Kazakhstan, reduces the risk of congestion, and increases the capacity to transfer power between the grids. This is important for seasonal mutual power exchanges: in the summer, Kazakhstan can receive electricity from Kyrgyzstan as part of hydropower management, and during other periods, it can support Kyrgyzstan with power supplies.

The Frunze–Kemin/Bishkek-500 project addresses a domestic need in Kyrgyzstan, but has a significant regional impact. Without strengthening Kyrgyzstan’s domestic grid, even the existence of a cross-border line does not guarantee a stable supply of power. The project enhances the reliability of the domestic grid, improves the utilization of the Naryn Cascade, supports the integration of AGC-participating generating units into the AGC, and creates a more stable foundation for power supplies to Kazakhstan and Uzbekistan.

Kyrgyzstan’s hydropower flexibility can become a marketable product only if it is physically deliverable and digitally controllable. Therefore, the investment rationale for this interface must include not only transmission lines, but also automated control systems, telemetry, commercial metering, and payment rules for ancillary services.

Fergana power hub

The Fergana power hub is one of the most critical sections of the CAPS. It is connected to Uzbekistan, Kyrgyzstan, Tajikistan, and the CASA-1000 systems. Constraints in this hub affect regional trade, power supply to Kyrgyzstan, power supply to northern Tajikistan, and the stability of Uzbekistan’s internal power grids.

The first component of the package is the reconstruction of the Kristall–Yulduz line and the construction of a second 220 kV transmission line. This project addresses the limited transmission capacity of the Kr-Y line at the Uzbekistan–Kyrgyzstan border.

The project is included in the first phase of REMIT and could yield rapid benefits for bilateral trade, emergency support, and imbalance settlement.

The second element is the Datka–Sughd line’s operating condition. The transit mode of this line could increase the transmission capacity to the Fergana power hub. At the same time, the operating regime for supplying a dedicated load in northern Tajikistan envisaged by CASA-1000 requires coordination of Uzbekistan’s internal system operation, metering, and the line’s mode during the winter.

The third element involves connecting the Datka–Sughd line to the Lochin substation and/or the Uzbekistan substation, or expanding the system via the Saykhun substation. These options could improve reliability, voltage levels, and transmission capacity to the Fergana power hub.

The development of these projects could help resolve the conflict between CASA-1000, Uzbekistan’s domestic operating conditions, and the supply of northern Tajikistan and Kyrgyzstan. Such a package would enhance not only the transmission capacity, but also the controllability of one of the most complex nodes in the CAPS.

Uzbekistan — Tajikistan

The Uzbekistan–Tajikistan connection has become particularly important following the restoration of the Tajik power system’s parallel operation with the CAPS. Tajikistan can provide the region with low-carbon electricity and balancing capacity during the summer, but its potential is limited by generation capacity and grid delivery capabilities.

One of the key projects is the new 500 kV Syr Darya Thermal Power Plant (or ACWA Syr Darya) — Sughd Substation transmission line, which is being constructed to connect to the existing 500 kV SDTES — Uzbekistan Substation line at the Sughd Substation. According to CDC Energia, the project is financed by the Asian Development Bank (ADB) and is expected to significantly improve the reliability of the power supply in northern Tajikistan.

This project could forge stronger ties with Uzbekistan, support future hydropower supplies, and strengthen the foundation for balancing power and ancillary services. However, there is a significant operational risk: once the interconnection is implemented, the left branch from the Sughd Substation will have a strong connection to the Syr Darya Thermal Power Plant via two 500 kV transmission lines, while the right branch toward the Uzbekistan Substation will remain a bottleneck. Furthermore, part of the Sughd Substation’s consumption could be reallocated to be supplied by the Syr Darya TPP, which could overload the already congested transmission route between the southwestern and central parts of Uzbekistan’s power system.

Therefore, the Syr Darya/ACWA–Sughd project cannot be evaluated in isolation. Its system-wide value increases when linked to the Datka–Sughd project, the Saykhun project, the connection to the Uzbekistan Substation, and future projects to strengthen the right branch. This is a typical example of a project where local reliability and regional trade are closely intertwined.

For the region, the project is important as a way to transform Tajikistan's hydropower potential into a more accessible resource. Its impact should be assessed not only in terms of the reliability of northern Tajikistan's power supply, but also in terms of its ability to reduce curtailment of RE, provide balancing support (for example, for Uzbekistan's solar generation), and expand the future ancillary services market.

The Turkmenistan Route

The Turkmenistan route could expand access to surplus gas-fired capacity. In the current configuration, power is transmitted to the CAPS via the 500 kV Mary–Serdar–Karakul transmission line and the 220 kV Lebap–Karakul transmission line. The condition of the cross-border L-512 transmission line limits further increases in power output.

The 500 kV Atamyrat–Guzar transmission line enables direct power delivery to the Guzar substation. This configuration is linked to Turkmenistan's transition to parallel operation with the CAPS, as the island operation of the isolated generators at the Mary Thermal Power Plant is no longer feasible in this setup. Key conditions include emergency protection systems, synchronization, a contractual framework, and confirmed transmission capacity through Uzbekistan's internal transmission lines.

The 500 kV Dashoguz TPP–Muruntau–Kyzylorda transmission line, proposed by KEGOC, would enable power to be transmitted from northern Turkmenistan through Uzbekistan to the southern region of Kazakhstan. The potential benefit lies in supporting the Shymkent power hub and bypassing some of the congested sections of the Uzbek grid. The scalability of this route also depends on the progress of Turkmenistan's parallel operation with the CAPS.

The Turkmenistan route is a strategic option for enhancing regional flexibility and thermal generation reserves. It can improve reliability during periods of stress, but requires careful planning of the technical interconnection scheme, emergency-control systems, financial projections, transit arrangements, and Turkmenistan's role in the future architecture of the CAPS.

North–South Transit in Kazakhstan and Back-to-Back HVDC (B2B)

The North–South transit corridor in Kazakhstan is one of the region's most significant systemic constraints. It supplies Kazakhstan's southern load centers, while also affecting CAPS stability. Large CAPS imbalances can drive unscheduled flows onto this corridor and increase overload risk.

The L-530, L-532, and L-539 transmission lines form a critical interface between the CAPS, the Kazakhstan UES, and the wider CIS interconnection. They are among the key bottlenecks affecting both Kazakhstan's internal transfers and CAPS stability. KEGOC is examining an approximately 1,500-km, 2,000-MW HVDC link from Ekibastuz GRES-1 to the Zhambyl or Shymkent area. CDC Energia has also proposed assessing a back-to-back HVDC interconnection at the CAPS–Kazakhstan interface, which could

enable controlled power exchange between synchronous areas without opening the existing 500 kV CAPS ring.

This issue goes beyond conventional grid reinforcement because it changes the operating relationship among Kazakhstan's UES, the CAPS, and Russia's UES. An internal HVDC link in Kazakhstan would reinforce north-to-south transfer capability within the country. A back-to-back HVDC interconnection at the CAPS–Kazakhstan interface would instead create a controllable boundary between synchronous areas and could reduce the risk of uncontrolled power swings on Kazakhstan's north–south corridor.

Both options involve large-scale systemic solutions and require a separate preliminary feasibility study.

Digital Tools

Digital grid solutions are one of the most important elements of the program. Their implementation is cheaper and faster than building large-scale transmission lines, and they directly enhance the utility of the existing grid. Within the CAPS, digital infrastructure is necessary for critical functions: monitoring balance flows, calculating deviations, automatic control, improving observability, financial settlements, and reducing conservative transmission interface constraints.

SCADA provides near-real-time monitoring and control of power system facilities: telemetry collection, parameter monitoring, command issuance, and event logging. WAMS/WACS, based on synchronized phasor measurements, extends observability to the inter-system level, enables monitoring of angles, frequency, power fluctuations, and early signs of instability, and, in a more mature configuration, supports automated control actions. AGC is used for automatic regulation of frequency and scheduled interchange, which is particularly important with the growth of cross-border trade, RE, and balancing energy. Settlement metering forms a commercially significant measurement base for accounting for actual power flows, calculating deviations, and paying for ancillary services. Secure communication channels are of particular importance, as they ensure the reliable and cybersecurity-compliant exchange of dispatch, commercial, and emergency data between national operators and the regional coordinator.

The current status of these systems, together with the data management requirements, is described in [Chapter 4](#); [Table 24](#) summarizes their functions, system effects, and KPIs.

Digital infrastructure is at least as important for integration as physical transmission infrastructure. A day-ahead market depends on settlement-grade metering and transparent transfer-capacity calculations. An ancillary services market depends on AGC, telemetry, and verification of service delivery. High shares of renewable generation require fit-for-purpose grid codes, forecasting, and validated dynamic models. Digital systems therefore have investment value in their own right.

↓ Table 24. Description of Digital Network Tools

Element	Function	System effect	KPI
AGC Coordination Center, CDC Energia	Frequency and scheduled-interchange control	Reduction of uncompensated imbalances and support for the ancillary services market	Number of connected stations, reduction in deviations
WAMS/PMU	Extended stability observability	Early detection of hazardous operating conditions and justification of permissible transfer limits	Coverage of critical transmission interfaces
WACS	Wide-area control	Increased net transmission capacity and reduced risk of accidents	Increase in allowable transfer limits
Regional automated settlement metering system	Commercial metering of cross-border flows	Financial settlements, charges for deviations, accounting for emergency power	Percentage of metering points covered
Secure data exchange channels	Secure exchange of dispatch and commercial data	Increased trust and cyber resilience of the regional architecture	Channel availability, transmission latency, number of incidents
Development of RE forecasting systems	Generation forecasts for the "day-ahead" market, real-time market, and dispatch operations	Reduction in "just-in-case" reserves and curtailment of RE	Forecasting error, extent of curtailment of RE

Source: Compilation by EDB experts based on CDC Energia.

Priority projects form several packages: Uzbekistan–Kazakhstan, Kazakhstan–Kyrgyzstan, the Fergana power hub, Uzbekistan–Tajikistan, the Turkmenistan corridor, the northern loop, and digital architecture. Their overall function is to reduce the total cost of reliability and improve the controllability of the energy transition.

These investments can help the region not only build more generation capacity, but also use existing and new capacity more efficiently, safely, and with greater investment predictability. A project is highly attractive when it removes a specific constraint, delivers a measurable system-wide effect, supports the market architecture, and enhances the reliability of the CAPS.

9.

EXTERNAL INTERCONNECTIONS



External interconnections can enhance Central Asia's strategic value. They expand markets, create new investment opportunities, attract external partners, and help countries in the region diversify their energy ties. However, their practical impact depends on the state of the internal core of the CAPS.

If the domestic system operates with overloaded transmission lines, limited digital monitoring, incomplete commercial metering, and a shortage of reserves, external projects begin to compete for grid capacity, water, available power, and management attention. With a well-managed internal loop, external initiatives become a source of additional resilience: they provide markets for new electricity, channels for green exports, access to capital and technology, reserve capacity, and a broader portfolio of commercial options.

External vectors should be viewed as a portfolio of opportunities at various stages of maturity. The southern CASA-1000 route already has a design and infrastructure foundation. The northern vector through Kazakhstan, Russia, and the broader Eurasian synchronous area serves to ensure reliability, frequency stability, and redundancy. The eastern route to China is linked to a large potential market, capital, and technology, but requires verification of a confirmed buyer, standards, and a contractual framework. The Trans-Caspian Green Energy Corridor is a long-term strategic option for green energy exports. The southwestern route from Turkmenistan to Iran involves grid synchronization, the possible use of a direct current interconnector, and Turkmenistan's future role as a regional energy hub.

↓ **Figure 12. Map of External Interconnections**



Sources: EDB, CDC Energia.

Among the external corridors, the Russia–Kazakhstan interface is already operationally significant and provides the CAPS with an indirect connection to Russia’s UES through Kazakhstan. Unlike the southern, eastern, and Trans-Caspian routes, which remain at different stages of implementation or feasibility assessment, the Russia–Kazakhstan interface already contributes to frequency stability, reserves, and emergency support for the joint system. Its value to the CAPS depends not only on the availability of Russian capacity but also on control of scheduled and unscheduled interchanges at the Russia–Kazakhstan border, the security of Kazakhstan’s North–South corridor, and the ability of the Kazakhstan UES to deliver support to its southern zone and onward to the CAPS interface. The northern route should therefore be viewed as an existing reliability and reserve interface whose value depends on stronger AGC coordination, clear imbalance-settlement rules, and reinforcement of critical transmission interfaces within Kazakhstan.

External connectivity does not replace internal regional cooperation; rather, it serves as an extension of it. As the internal regional market develops, external markets gain a more stable technical and commercial foundation. This approach reduces risks and enhances the bankability of projects.

Southern Corridor — CASA-1000

CASA-1000 is a Central Asian external energy corridor with a high degree of readiness. Its primary function is to transmit summer hydropower from Kyrgyzstan and Tajikistan to South Asia via Afghanistan to Pakistan. The project allows upstream countries to monetize a portion of their seasonal hydropower resources, while enabling receiving markets to obtain additional electricity during periods of high demand.

The project involves the construction of a 500 kV transmission line from the Datka Substation to the Sughd Substation, with a total length of approximately 485 km, 450 km of which run through Kyrgyzstan, followed by a 260-km 500 kV transmission line from Sughd to Sangtuda, a 1,300 MW converter substation in Sangtuda, a high-voltage direct-current line from Sangtuda to Nowshera in Pakistan with a length of approximately 750 km, and a 1,300 MW inverter substation in Nowshera. The Kyrgyz and Tajik sections were completed in 2026, and commissioning work is underway; the Afghan section remains a key condition for the project’s launch.

The World Bank notes that work in Afghanistan was suspended following the political changes in August 2021 and resumed in December 2024 after safeguards were put in place. As of December 2025, contractors were continuing their work, and the project is expected to be fully completed by the end of 2027. Kyrgyzstan, Tajikistan, and Pakistan have largely completed construction of their facilities and are awaiting the completion of the Afghan section for final testing of the HVDC system and the start of operations ([World Bank, 2026b](#)).

The system-wide importance of CASA-1000 is linked to three conditions. The first condition is seasonality. CASA-1000 is designed to supply surplus electricity during the summer growing season. The project must be coordinated with the water and energy management regimes of Kyrgyzstan and Tajikistan, domestic demand, reservoir management, and obligations to downstream countries. In years of low water flow

or high domestic demand, the amount of electricity available for export may be lower than projected.

At the same time, the original CASA-1000 resource model needs to be updated. The project was developed on the assumption that the existing hydropower plants in Kyrgyzstan and Tajikistan would generate a sufficient summer surplus after meeting domestic demand, and did not require the construction of new generating capacity. However, over the past decade, domestic demand has grown significantly; Kyrgyzstan has become a consistent net importer of electricity, and Tajikistan's available export capacity is already being used in trade with neighboring countries. Therefore, the mere existence of a physically completed transmission line does not in itself guarantee that it will operate at its design capacity: the determining factor is the residual summer export capacity remaining after meeting domestic demand, existing export obligations, and water management constraints.

The second condition is the Datka–Sughd mode. The CASA-1000 project's plan to operate the Datka–Sughd line in dead-end mode to supply a dedicated load in northern Tajikistan could increase the load on existing, already heavily loaded sections of Uzbekistan's power grid if the shortfall in Kyrgyzstan is covered by transit through Uzbek networks. Therefore, it is advisable to discuss the line's operating condition, the method of electricity metering, and the operation of the Datka–Sughd line during the winter in coordination with the CAPS.

Box 3. Key Risks Associated with the CASA-1000 Project

The rivers of Central Asia are transboundary in nature, and the supply of electricity outside the region inevitably relies on a closed watershed with limited water reserves that are subject to significant seasonal fluctuations. Therefore, an assessment of the CASA-1000 project cannot be limited to grid and commercial considerations—it must explicitly account for the following cumulative risks.

Schedule risk. According to the initial feasibility study, the CASA-1000 project was supposed to be commissioned in 2017; the actual completion date has been pushed back to 2027, in part due to political instability in Afghanistan. The project is already about 10 years behind schedule.

The risk of a mismatch between the corridor's readiness and export capacity.

The original CASA-1000 model assumed the export of the existing summer hydropower surplus from Kyrgyzstan and Tajikistan and was not directly tied to the construction of new large-scale hydropower plants. However, by the time the corridor is expected to become operational in 2027, this assumption has become less reliable. Kyrgyzstan is currently a net importer of electricity, while Tajikistan's available summer export capacity is simultaneously in demand by the domestic market and existing regional supply routes. Therefore, during the period between the commissioning of CASA-1000 and the emergence of new large-scale generating capacity (tentatively in 2033), the actual utilization of the corridor will depend on water availability, the growth rate of domestic demand, and the volume of the remaining summer surplus available after other obligations have been met.

Financial and construction risks. Completing both Kambarata-1 and Rogun HPPs will require significant direct investments. International experience with large-scale dam projects shows that, on average, the cost of major hydropower projects has exceeded the initial estimate by 96 percent, with a median overrun of approximately 30 percent; the average schedule delay was 44 percent ([Ansar et al., 2014](#)); that is, the risk of a further delay beyond 2033 should be considered the baseline scenario, not an exception.

Capacity utilization and payback risk. The CASA-1000 lines are designed to transmit seasonal surpluses of electricity generated during the summer irrigation season. For the rest of the year, the lines remain significantly underutilized, which poses risks to the reliability of the grid infrastructure, increases operating costs, and will likely require subsidies for national operators—an additional burden on the budgets of participating countries with limited fiscal flexibility. Given these circumstances, the project's stated payback period remains uncertain.

Risk of a change in the project's strategic function. One possible solution to the load issue is to integrate power grids from outside the region (such as Russia) into the project. In this case, CASA-1000 would transform from a southern export corridor for Central Asian countries into an interregional transit line, thereby altering its original strategic rationale.

A risk not accounted for in the initial feasibility study. The CASA-1000 calculations did not take into account the Kosh-Tepa Canal (Afghanistan) with its water intake from the Amu Darya, which is expected to reach its design capacity by 2028–2030—virtually simultaneously with the filling period of the Rogun HPP reservoir. The temporal overlap of these processes creates a cumulative risk to the region's water and energy security, which requires a joint—rather than isolated—assessment.

The third condition is Afghanistan as the central link. The World Bank explicitly notes that CASA-1000 cannot operate without the completion of the Afghan section, as it connects all four participating countries. Failure to complete the project creates the risk of underutilization or depreciation of infrastructure assets valued at approximately \$1 billion. To mitigate these risks, the project in Afghanistan has been resumed through a separate implementation framework: construction payments and future revenues are managed outside of Afghan government systems, utilizing external monitoring, offshore accounts, and separate control procedures ([World Bank, 2026b](#)).

Afghanistan's northeastern power grid is not yet a stable transit circuit for the CAPS. It operates in island mode: in winter, primarily from Uzbekistan via the Surkhan–Puli-Khumri–Kabul route; in summer, from Tajikistan via the Sangtuda–Puli-Khumri–Kabul route. The inclusion of these lines in the transit route via the Puli-Khumri substation is limited by the requirements for stable parallel operation, which leads to the separation of busbar systems at most NEPS substations.

↓ Table 25. CASA-1000 Project Parameters

Parameter	Description	Value for the CAPS
Participating countries	Kyrgyzstan, Tajikistan, Afghanistan, Pakistan	Southern interregional corridor: Central Asia–South Asia
Basic function	Seasonal export of summer hydropower	Monetization of the hydropower surplus of upstream countries
Technical configuration	AC interconnections in Central Asia and HVDC transmission toward Pakistan	Controlled transmission through weak and non-synchronous sections of the grid
Critical section	Afghan transit segment	Key prerequisite for the full corridor’s actual operability
Financial protection	A separate implementation and settlement framework for the Afghan segment	Reduction of payment, operational, and political-financial risks
Connection to the internal CAPS	Datka–Sughd, Fergana power hub, NEPS, water and power regimes	Need to coordinate external exports with domestic power flows and hydrological regimes
Key constraints	Seasonality of supply, transit security, line operating conditions, commercial metering, payment model	Requirements for operational protocols, settlement, and risk allocation

Sources: Adapted by EDB experts based on CDC Energia, [World Bank \(2026b\)](#).

CASA-1000 creates a high-capacity seasonal export channel, but the actual annual volume of supplies will depend on water availability, the readiness of the Afghan section, operating conditions, and contractual terms. Electricity transmission under the CASA-1000 project is scheduled to begin in 2027 following the completion of construction work in Afghanistan.

CASA-1000 is significant as a practical example of an external interconnection that requires internal coordination. Southern exports become sustainable when the CAPS is able to simultaneously manage hydropower resources, the grid, peak loads, internal electricity shortages, and commercial obligations.

Northern Vector — Russia and the EAEU

The northern vector serves a different purpose. Unlike CASA-1000, it is not primarily an export route. Its importance lies in reliability, frequency stability, redundancy, and the CAPS’s integration with the broader synchronous area via the Kazakhstan and Russian power grids.

The southern part of Kazakhstan is part of the CAPS, but its connection to northern Kazakhstan is critical for meeting demand. The southern region of Kazakhstan covers approximately half of its energy balance with its own generation and the other half with power flows from northern Kazakhstan via three 500 kV transmission lines. This transmission capacity is used almost entirely to serve domestic consumers

in Kazakhstan, and uncompensated imbalances in the CAPS can place an additional load on the North–South transmission line. In the event of an emergency shutdown of this transmission line, the southern regions of Kazakhstan lose approximately 2,000 MW of power flow, which complicates the emergency response process in the CAPS.

The northern vector is also important for frequency stability. Currently, the CAPS is effectively interconnected with a broader area via Kazakhstan. This provides system stability but also makes the region sensitive to power swings, deviations in net power flows, and the status of Kazakh transit. The L-530, L-532, and L-539 interconnections, which link the CAPS to the Kazakhstan and Russian power grids, represent one of the most significant bottlenecks and affect the stability of the entire CAPS.

There are two major conceptual solutions for the northern route. The first is the KEGOC project to build a high-voltage direct-current transmission line from Ekibastuz State Power Plant No. 1 to the Zhambyl or Shymkent substation, approximately 1,500 km long and with a transmission capacity of 2,000 MW. The second is a proposal by CDC Energia to consider a back-to-back HVDC (B2B) connection at the border between the CAPS and the UES of Kazakhstan, in order to transition from parallel operation to controlled joint operation via DC interconnections without breaking the 500 kV CAPS loop.

↓ **Table 26. Parameters of the Northern Vector**

Element	System function	Critical parameters
Kazakhstan's UES/ Russia's UES	Frequency stability, redundancy, external synchronous reference	Commercial rules, balance-flow modes, cost of deviations, emergency support conditions
North–South Transit in Kazakhstan	Load coverage for the southern zone of Kazakhstan and indirect support for the CAPS	Interconnection capacity, N-1 criterion, demand growth in the southern zone, risk of overload due to imbalances in the CAPS
HVDC EGRES-1 — Zhambyl/Shymkent	Controlled expansion of Kazakhstan's domestic transmission	CAPEX, system-wide benefits for the southern zone, impact on the CAPS's net flows, integration with the existing grid
Back-to-back HVDC (B2B) at the border between Kazakhstan's UES and the CAPS	Controlled interface between synchronous zones	Frequency control of the CAPS, AGC Coordination Center, cost of the B2B HVDC interconnection, operational stability, liability allocation rules
AGC Coordination Center, CDC Energia	Regulation of frequency, power, and net power flows	Funding, implementation timelines, connection of AGC-participating generating units, requirements for telemetry and communication channels

Sources: Adapted by EDB experts based on CDC Energia.

The Northern Vector is a reliability and redundancy loop. Its future architecture should reduce the load on the North–South transit corridor in Kazakhstan and improve the controllability of power flows between the CAPS and the Kazakhstan UES.

The northern vector helps improve reliability without excessive national redundancy. Its value increases with the development of the additional digital tools discussed earlier. Without these elements, external synchronous support may mask internal controllability issues rather than resolve them.

Eastern Vector — China (XUAR)

China is the largest energy and technology market, with extensive experience in HVDC, RE, grid construction, battery energy storage systems, and industrial manufacturing of power equipment. For Central Asia, this means potential access to capital, technology, and long-term demand.

At present, the eastern route should be viewed as a strategic project option rather than an established export corridor. The publicly available materials cited in this report do not provide confirmed details regarding the buyer, the volume of supply, the route, the technical design, the business model, or the allocation of risks.

The Chinese market is heterogeneous. The Xinjiang Uyghur Autonomous Region (XUAR) is geographically close to Central Asia, but proximity does not automatically translate into demand for imported electricity. China is actively developing its own power generation capacity, ultra-high-voltage grids, RE sources, and interregional transmission lines. Therefore, the key question must be framed in practical terms: Is there a specific creditworthy offtaker, a connection point, a pricing formula, and a long-term contractual model?

Technically, the eastward transmission route will likely require HVDC or another controllable interconnection scheme. This is due to the distances involved, differences in standards, and the need to control power flows and mitigate risks to system stability. For Central Asia, this technology may be an advantage: HVDC allows for the management of exports without strict system synchronization. However, this technology is capital-intensive and requires a large guaranteed volume of supply.

↓ Table 27. Parameters of the Eastern Vector

Criterion	Required conditions	Comments
Destination market	A verified buyer in the XUAR or another region of China	A large market does not guarantee demand for imports.
Technical configuration	HVDC or other managed connectivity	Controlled transmission without strict synchronization and reduced risks for the CAPS
Technical standards	Compatibility of requirements for connection, protection, telemetry, data exchange, and emergency modes	Reduced risk of project cost overruns, delays, and operational constraints
Business model	Price, PPA term, currency terms, transit payments, losses, curtailment provisions	Investment feasibility only with a confirmed payment and contractual framework

Resource base	Defined export portfolio: RE, hydropower, thermal capacity, or a hybrid scheme	Preventing a decline in internal reliability and competition for scarce resources
Regulatory framework	Cross-border licenses, guarantees of origin, network access, settlement rules, and dispute resolution	Predictability of access, tariffs, and the parties' liabilities
Goeconomic profile	Balancing access to markets, capital, and technology with the protection of national interests	Reducing the risk of asymmetric dependence on a single external source

Source: EDB.

The eastern vector is particularly sensitive to the structure of benefits. If a project focuses solely on exports from individual large power plants, it may do little to benefit the CAPS. If it is integrated into the regional architecture, however, it can increase the value of RE, generate new external demand, support HVDC capabilities, and attract capital.

The eastern vector with China is a long-term strategic option. Its implementation requires a separate preliminary feasibility study, a confirmed buyer, an assessment of standards, and an analysis of the impact on the internal reliability of the CAPS.

China could become a source of technology and capital, but internal regional coordination remains an essential foundation. A strong CAPS strengthens the region's negotiating position and makes potential exports less dependent on a single external buyer.

Western Vector — Trans-Caspian Green Corridor

The Trans-Caspian Green Energy Corridor is a strategic priority and, at the same time, one of the most complex foreign policy priorities. Its purpose is to establish a route for exporting RE from Central Asia through the Caspian Sea and Azerbaijan, and onward to the Black Sea and European energy markets.

Until the feasibility study is completed, this corridor should be viewed as a strategic option rather than a confirmed route for implementation. In March 2026, a kick-off workshop on the first phase of the feasibility study was held in Baku, with participation from Azerbaijan, Kazakhstan, Uzbekistan, transmission operators, regulators, the Asian Development Bank, the Asian Infrastructure Investment Bank, and other stakeholders. Following the meeting, key technical prerequisites, data requirements, and next steps were agreed upon to complete the first phase of the feasibility study and prepare for the second phase.

CESI, appointed by the Asian Development Bank to carry out the first phase of the feasibility study, states that the study should assess the technical, economic, regulatory, and environmental viability of the proposed infrastructure. CESI's mandate includes modeling cross-border exchanges, conducting system studies, selecting optimal routes for onshore and subsea cable sections, performing conceptual design of the HVDC infrastructure, and defining the commercial framework and business model. CESI also notes that the corridor is designed to integrate up to 5 GW of RE by 2030 ([Azerbaijan Ministry of Energy, 2026](#); [CESI, 2026](#)).

↓ Table 28. Parameters of the Trans-Caspian Green Corridor

Criterion	Necessary conditions	Comments
Technical configuration	Caspian cable, onshore converter stations, HVDC infrastructure, interconnection with the grids of Kazakhstan, Uzbekistan, and Azerbaijan	Technical feasibility, losses, reliability, and capital costs
Resource base	RE export portfolio, generation profile, additionality of projects, availability of reserves	Confirmation that exports are based on additional net generation, rather than on the redistribution of scarce energy
Grid readiness	Domestic grids of Kazakhstan and Uzbekistan, RE output, interconnection with Azerbaijan and subsequent transit systems	Preventing the blocking of internal corridors and an increase in curtailment
Regulatory framework	Grid access, cross-border trade, certification of electricity origin, accounting for losses and curtailments	Verifiability of green origin and compatibility with target market requirements
Business model	Confirmed buyer, PPA/CfD, transmission tariff, loss allocation, payment guarantees	Project bankability and allocation of commercial risks
Operational coordination	HVDC dispatch, emergency modes, ramp-rate limits, balancing, curtailment rules	Safe operation of the corridor without compromising the stability of the CAPS
ESG and permitting framework	Offshore section, environmental constraints, land acquisition, approval procedures, and safeguards	Mitigation of environmental, social, and permitting risks
Institutional model	Allocation of roles among TSOs, regulators, market operators, investors, and customers	Manageability of a multilateral project structure

Sources: Compiled by EDB experts based on data from the Ministry of Energy of Azerbaijan and CESI/ADB.

The Trans-Caspian Corridor should be viewed as a strategic, long-term option for green exports. Its priority will depend on the results of the feasibility study, a confirmed buyer, certification of electricity origin, capital costs, and the capacity of the CAPS to support exports without compromising reliability.

This corridor is closely linked to the “Middle Path” strategy. It can enhance the investment appeal of RE, provide an export market, stimulate the certification of green electricity, and support the technological modernization of power grids. If the domestic grid and market architecture develop ahead of schedule, it could become a source of sustainable export revenue. If domestic infrastructure lags behind, there will be a risk of competition for transmission capacity, flexibility, and investment.

A separate risk is the lack of harmonization in guarantees of electricity origin. Green exports require uniform certification rules, a registry for tracking origin, audit reports,

and rules on “additionality” and volume reconciliation. Without these, it will be more difficult to verify the green status of a supply to buyers, European regulators, and international financial institutions.

Southwestern Vector — Turkmenistan–Iran

The southwestern vector involves Turkmenistan, Iran, Afghanistan, and Turkmenistan’s potential parallel operation with the CAPS. This direction differs from the others in that the main issue here relates primarily to the synchronization scheme.

Currently, Turkmenistan operates in parallel with Iran’s power grid and supplies electricity to the CAPS via islanded configurations. This model has made it possible to increase supplies to Uzbekistan and Kyrgyzstan, but it has its limitations. CDC Energia notes that the “island” mode reduces the reliability of the Turkmen power grid, since it requires the allocation not only of generators, but also of the 500 kV and 220 kV transmission lines. If the current configuration remains in place, the potential for expanding supplies is limited.

A critical issue concerns the 500/400 kV interconnections toward Iran currently under construction and in the planning stages. The interconnection of power lines via a 500/400 kV transformer link has not been sufficiently studied and does not ensure stable parallel operation of the power systems of Iran and Turkmenistan, on the one hand, and the CAPS, on the other. It is proposed to install a DC interconnector instead of the transformer link. Such a configuration would allow Turkmenistan to resume parallel operation with the CAPS, while simultaneously connecting to Iran via a controlled DC interconnector.

This proposal is of regional significance. With a DC interconnector, Turkmenistan could become a hub for electricity exchange between Iran, the CAPS, Kazakhstan’s UES, and Russia’s UES. CDC Energia specifically notes the potential value of daily exchanges, taking into account time zones and possible seasonal variations.

The southwestern vector could strengthen the regional portfolio of options, but its development depends on the choice of a technical scheme for interconnecting Turkmenistan with Iran and the CAPS. A controlled scheme via back-to-back HVDC appears to be the most promising for further analysis. It requires a separate feasibility study, an assessment of capital costs, stability, a business model, and intergovernmental agreements.

Turkmenistan could provide the region with additional gas-fired power generation capacity, reserves, and operational flexibility. This resource must be integrated into a managed, technically stable, and contractually transparent framework.

↓ Table 29. Turkmenistan–Iran Interconnection Options

Option	What this means	Potential Impact	Main Risk
Continuation of islanded configurations	Turkmen power plants and grids are designated to supply the CAPS	Maintenance of current supply levels	Limited scalability and lower reliability
500/400 kV transformer interconnection with Iran	Synchronous interconnection without a B2B HVDC	Theoretically simplifies grid interconnection	According to CDC Energia's assessment, does not ensure a stable configuration with the CAPS and Iran
Turkmenistan–Iran HVDC	Controlled DC interconnection between Turkmenistan and Iran	Ability for Turkmenistan to operate in parallel with the CAPS and exchange power with Iran via the HVDC interconnector	Capital costs, feasibility study, contractual framework
Turkmenistan as a hub	Turkmenistan connects the CAPS, Iran, Afghanistan, and potentially the northern loop	Daily and seasonal arbitrage, additional reserve	Requires political, technical, and commercial solutions

Sources: Adapted by EDB experts based on CDC Energia.

Comparative Matrix

A comparative assessment of external markets must go beyond the scope of potential export volumes. For the CAPS, it is of fundamental importance to determine the system-wide function that each vector fulfills: reliability, seasonal exports, access to external demand, green certification, managed connectivity, or transit. Therefore, the matrix compares the routes based on their degree of maturity, technical conditions, requirements for internal grids, payment models, operational stability, and bankability. This approach allows for the evaluation of external corridors not as competing export routes, but as a portfolio of options, the value of which depends on the controllability of the CAPS's internal core.

The feasibility of external connections is determined by the degree of readiness of the CAPS to manage exports, transit, and interconnection with external power systems. Critical conditions include confirmed available transmission capacity, the stability of key sections, operational coordination of hydropower resources, emergency response systems, commercial metering, secure communication channels, agreed-upon rules for deviations, as well as a creditworthy offtaker and a contractual risk-sharing model. Therefore, external corridors should be viewed not as standalone export projects, but as derivatives of the region's internal controllability: the higher the technical and design maturity of the CAPS, the greater its system-wide and investment value.

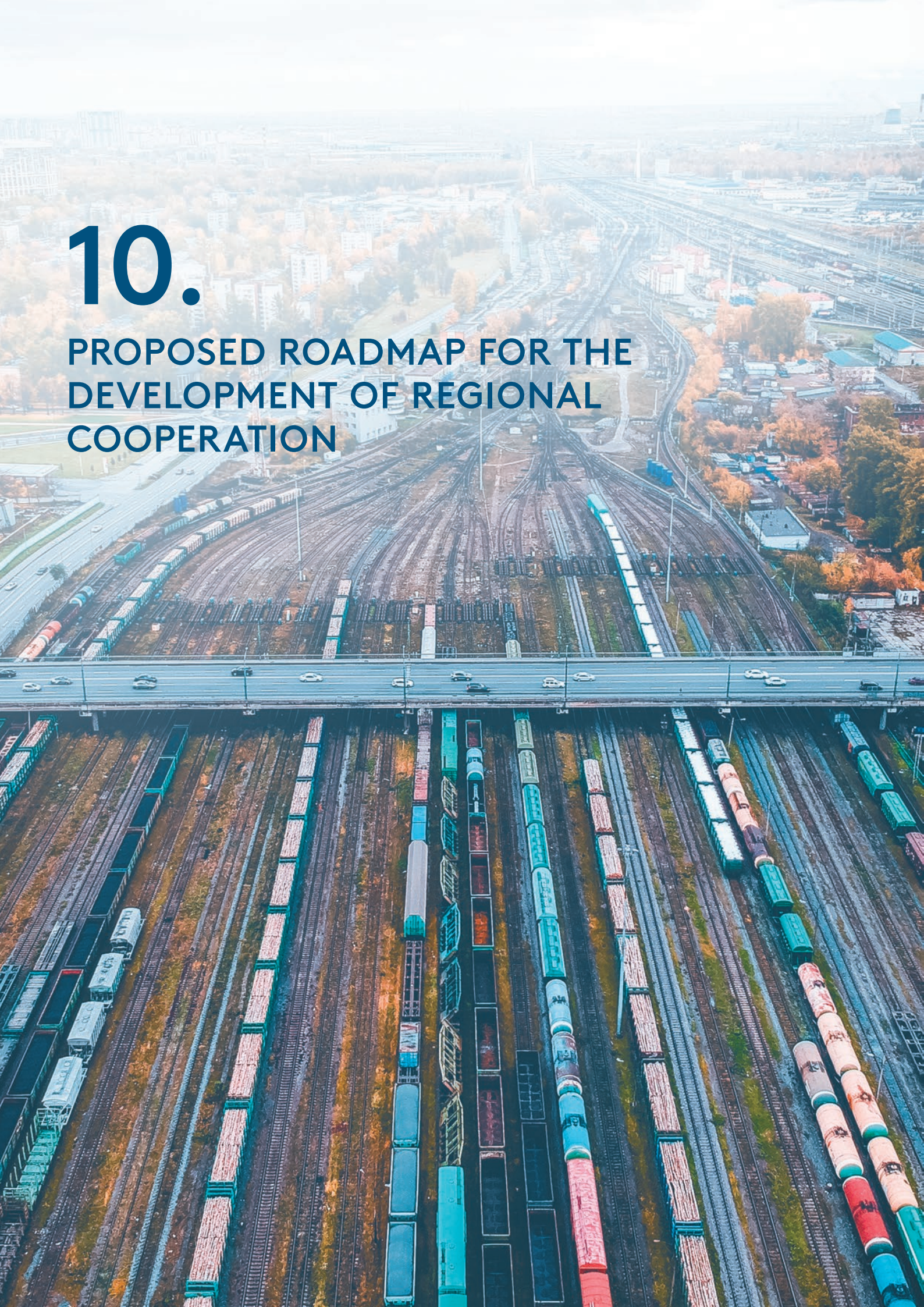
↓ Table 30. EDB's Expert Assessment of Central Asia's External Energy Corridors

Vector	Maturity	System function	Main risk
CASA-1000	Current project implementation	Seasonal hydropower exports to South Asia	Seasonality, security, Datka–Sughd, metering, payment model
Northern Vector	Current vector; expansion may require a feasibility study	Reliability, frequency, redundancy	Transit load on Kazakhstan's North–South grid, imbalances, regulatory and sanctions-related restrictions
China/XUAR	Concept	Potential market, capital, HVDC	Confirmed buyer, standards, bargaining asymmetry
Trans-Caspian Corridor	Feasibility study stage	Green exports and certification of origin	Capital expenditures, ESG, buyer, grid readiness
Turkmenistan–Iran	Infrastructure is in place; synchronization scheme requires a solution	Gas capacity, southwestern hub, exchanges with Iran	B2B HVDC, contracts, parallel operation, emergency control
Afghanistan as a southern extension	Limited under the current NEPS	Destination market and potential transit	Stability, payments, security

Sources: Compilation by EDB experts based on data from CDC Energia, the [World Bank \(2026b\)](#), the Ministry of Energy of Azerbaijan, and CESI/ADB.

Central Asia can develop external corridors as an extension of its internal modernization. A strong CAPS enhances reliability, reduces the cost of integrating RE, improves the region's negotiating position, and makes external projects more bankable. In this context, external corridors become an extension of the "Middle Path" strategy: they help diversify markets, attract capital, enhance reliability, and reduce the cost of the energy transition.

The main conclusion of this chapter is that Central Asia's external connectivity will be sustainable only if it has a strong internal core. External corridors must be supported by a managed network, verified available transmission capacity, commercial metering, financial settlements, hydropower coordination, rules for deviations, ancillary services, and an investment portfolio that addresses the actual constraints of the CAPS. Only then will external connections enhance regional reliability rather than create new competing demands on the grid, water resources, and available capacity.

An aerial photograph of a vast railway yard. In the foreground, numerous freight trains are parked on parallel tracks, featuring various colored containers and cargo. A multi-lane highway bridge spans across the middle of the yard. Beyond the tracks, a cityscape is visible under a hazy sky, with buildings and trees showing autumnal colors.

10.

PROPOSED ROADMAP FOR THE DEVELOPMENT OF REGIONAL COOPERATION

The roadmap presented here is an analytical proposal by the EDB and does not reflect a reform schedule agreed upon by the countries or commitments by national authorities. Its timeframes are indicative. The transition between stages should be determined not only by calendar deadlines but, above all, by the readiness of data, metering systems, networks, settlement mechanisms, and institutions.

Thus, the roadmap should be viewed not as a rigid timeline for market launch, but as a sequence of readiness levels. Progression to each subsequent level is possible only upon fulfillment of the basic conditions of the previous stage (maturity-based roadmap): observability of the operating condition, settlement metering, deviation rules, calculation of available transfer capacity, payment discipline, and operational coordination.

This approach is consistent with the logic of the “Middle Path” strategy. Regional cooperation must simultaneously improve reliability, maintain energy affordability, and ensure the managed integration of RE sources. First, the system must be able to monitor and measure operating conditions. Only then is it possible to safely allocate limited transmission capacity and launch short-term trading. After that, flexibility, reserves, and ancillary services can become measurable and marketable products. At a more mature stage, the foundation is laid for regional resource adequacy assessments, recognition of reliable cross-border resource contributions, and more sustainable access to external energy corridors.

The technical infrastructure for this roadmap is already being established. The regional settlement metering system has been purchased and is being installed; the design and cost estimate documentation for the central coordinating system of the AGC has been prepared; WAMS has been integrated into KEGOC’s SCADA using a limited set of sensors, the KEGOC WACS has increased transmission capacity by 250 MW, and since 2026, the REMIT program has been working to supplement bilateral agreements with pilot short-term trading. The World Bank describes REMIT as a 10-year, three-phase program focused on increasing regional trade, expanding transmission capacity, digitizing grids, and integrating clean energy ([World Bank, 2026a](#); [World Bank, 2026c](#)).

Short-Term Horizon (2026–2028)

The first horizon establishes the operational and commercial foundation. At this stage, the priority is the reliable measurement and management of existing cross-border flows: AGC, secure channels, telemetry, the transaction registry, imbalance settlement rules, emergency power, inter-operator exchange of balancing energy, and preparation for a pilot market.

This phase could result in a system in which every delivery is visible to the system operator, every transaction has a schedule, every deviation is measured, emergency support is documented in a separate protocol, and actual flows are confirmed by settlement metering. This reduces the risk of uncompensated imbalances, increases trust among participants, and lays the foundation for future financial settlements.

↓ Table 31. Necessary Components in the Short Term

Area	Stage description	Responsible functions	Result
Settlement metering	Commissioning of the regional settlement metering system and integration with national systems	CDC Energia, national system operators, grid companies	Unified database for inter-system power flows
Secure channels	Secure exchange of dispatch and commercial data	CDC Energia, NSOs, IT departments	Reliable exchange of operational and billing information
Data management regulations	Uniform rules governing the composition, frequency, accuracy, access, auditing, and use of data	CDC Energia, NSOs, regulators	Data forms the foundation of the market, ancillary services, and post-incident analysis
Transaction registry	Register of cross-border contracts, schedules, delivery points, and balance responsible parties	NSOs, CDC Energia, market platform operator	Visibility of commercial flows for dispatch
Imbalance settlement	Basic rules for imbalance settlement	NSOs, regulators, CDC Energia	Responsibility for discrepancies between the schedule and actual flows
Emergency power	Emergency support protocol and separate accounting for emergency power	NSOs, CDC Energia, regulators	Emergency assistance without billing disputes
Balancing energy	Inter-operator exchange of balancing energy	NSOs, CDC Energia	First level of the flexibility market
RE telemetry	Connecting large-scale RE sources to telemetry and forecasting	NSOs, RE plant operators	RE growth without loss of observability

Sources: Proposals from EDB experts, based on materials from CDC Energia, REMIT, and international experience.

A key component of the first horizon is a clear division of roles. CDC Energia can serve as a coordinator, a platform operator, or a coordinator of financial settlements. National system operators retain control over internal system operation and the operational security of their power systems. This model reduces political sensitivity and makes regional coordination compatible with national responsibility for the reliability of energy supply.

Medium-Term Horizon (2028–2030)

The second horizon transitions basic operational control into a limited market architecture. The region is moving from a transaction registry and deviation accounting to the calculation of available transmission capacity, a “day-ahead” pilot market, transit rules, payment mechanisms, and stricter requirements for RE and BESS.

The central requirement of this phase is the TTC/TRM/NTC/ATC methodology. The “day-ahead” pilot market must operate with confirmed available transmission capacity after accounting for bilateral contracts, seasonal water-power agreements, and mandatory operational constraints. This approach aligns the market with the physics of the grid and reduces the risk of overloads.

↓ Table 32. Necessary Components in the Medium Term

Area	Stage description	Dependency	Result	KPI
NTC/ATC	Methodology for calculating net and available transfer capacity	SCADA, WAMS, operational calculations, N-1 criterion	Link between the market and grid physics	Share of transactions with confirmed ATC
Pilot DAM	Limited “day-ahead” market on top of bilateral contracts	Settlement metering, financial settlements, payment guarantees	First price signal	DAM transaction volume
Transit and network usage fees	Transparent rules for payment for transmission via a third-party network	Grid tariffs, losses, access rules	Protection of transit countries’ interests	Transit volume with settlements
Payment guarantees	Guarantees, escrow accounts, letters of credit, netting, default coverage fund	Financial market rules	Credit risk mitigation	Percentage of transactions with payment guarantees
Priority lines	Preparation and implementation of P1/P2 projects in the investment portfolio	Feasibility studies, financing, intergovernmental decisions	Increase in net transfer capacity	Increase in NTC/ATC
AGC Coordination Center	AGC Coordination Center, CDC Energia, and interconnection with national AGC systems	Funding, telemetry, AGC-participating generating units	Automatic control of scheduled interchange	Number of connected control stations
WAMS/WACS	Expansion of PMU and wide-area control	Critical sections, IT infrastructure	Improved observability and stability	Coverage of critical PMU sections
RE/BESS requirements	Requirements for fault behavior, models, telemetry, and controllability	Regulators, TSOs, investors	Safe connection of inverter-based generation	Share of RE/BESS with verified dynamic models
RE forecasting	Nationally integrated or regional forecasting center	RE data, meteorological data, market rules	Reduction in “just-in-case” reserves and RE curtailment	RE forecasting error, extent of RE curtailment
Green electricity certification	Register of guarantees of origin, additionality rules, and audit trail	External corridors, RE data, metering	Verifiability of green exports	Share of export shipments covered by guarantees of origin

Sources: Proposals by EDB experts, based on materials from CDC Energia, REMIT, and international experience, as well as data from the [IEA \(2024; 2025\)](#) and [ESMAP \(2026\)](#).

At this stage, grid projects take on market significance. The grid projects—the second 500 kV Shymkent–Tashkent TPP line, Muruntau–Shymkent, Kemin–Almaty, Frunze–Kemin/Bishkek-500, Kristall–Yulduz, Datka–Sughd, Syr Darya/ACWA–Sughd, and the digital package—are evaluated based on increases in net transfer capacity, reductions in congestion, decreases in curtailment of RE, improved observability, and support for DAM.

For regulators and international financial institutions, this horizon is particularly important. It demonstrates that an investment project is linked not only to line voltage or installed capacity, but also to measurable system-wide effects: transmission capacity, reduction of constraints, payment discipline, market transparency, and bankability.

Long-Term Horizon (2030+)

The third phase begins once reliable data, commercial metering, verified transmission capacity, digital control, and initial experience with market trading are in place. Integration shifts from trading electricity volume to trading services and reliability.

The key elements of this phase are the balancing market, ancillary services, regional resource adequacy assessments, recognition of reliable cross-border capacity contributions, and the development of external corridors. A fully fledged capacity mechanism can be considered after verifying payment discipline, tariff affordability, grid deliverability, ELCC, and the actual availability of fuel, water, BESS, and hydropower resources.

At this stage, the investment and system-wide value of RE and hydropower increases. RE sources become more bankable when the system reduces curtailment and compensates for operational flexibility. Hydropower plants gain the ability to monetize not only kWh but also balancing capacity, reserve capacity, and other services. This transforms hydropower agreements into the foundation of the future ancillary services market.

↓ Table 33. Necessary Components in the Long Term

Area	Phase description	Dependency	Result	KPI
Balancing market	A formalized balancing market on top of the inter-operator exchange	AGC, settlement metering, real-time data	Market-based payment for balancing energy	Volume of balancing energy
Ancillary services	Ancillary service products	Technical requirements, telemetry, performance verification	Payment for frequency, reserves, voltage, and rapid power changes	Volume of ancillary services, number of suppliers
Hydropower flexibility	Peak power, reserve, ramping capability, and seasonal flexibility	Hydropower agreements, AGC, water accounting	Monetization of hydropower flexibility	Volume of remunerated hydropower flexibility
BESS participation	BESS certification for rapid frequency response, frequency support, and balancing	MW/MWh, grid-forming mode, telemetry	Rapid system flexibility	Certified BESS capacity
Resource adequacy assessment	Regional probabilistic resource adequacy assessment	Data on demand, fuel, water, RE, and grids	Understanding the long-term risk of shortages	LOLE, EENS, capacity reserve
Reliable cross-border capacity contribution	Recognition of a reliable contribution from a neighboring resource	ELCC, grid deliverability, contracts	Shared use of reserves	Ability to reliably import capacity
Reliability options	Soft mechanisms for long-term reliability	Financial settlements, credit support, regulation	Resource readiness without a premature capacity market	Volume of reliability contracts
External energy corridors	CASA-1000, Northern Vector, China, Trans-Caspian Corridor, Turkmenistan–Iran	Domestic grids, confirmed buyer, HVDC/B2B, ESG	Diversification of markets and reserves	Actual deliveries and investment feasibility

Sources: EDB experts' proposals, based on materials from CDC Energia, REMIT, and international experience.

Potential Risks

Electricity integration is sensitive to technical, water-related, fuel-related, financial, institutional, and external factors. Taking these factors into account makes the sequence of actions more realistic and reduces the risk of unrealistic expectations regarding individual projects.

The main risk to implementation stems from a lag in institutional and digital readiness. If the market develops faster than the data, the network, payment discipline, and trust among participants, it could exacerbate tensions. Therefore, the roadmap is structured from simple to complex: metering, deviations, emergency support, capacity calculation, the “day-ahead” market, the balancing market, ancillary services, and resource adequacy assessment.

↓ Table 34. Register of Risks in Regional Cooperation

Risk	How it manifests	Impact	Mitigation measures
Hydrology	Low water levels reduce the availability of hydropower plants, summer exports, and the amount of hydropower flexibility.	High	P50/P90 water availability scenarios, low-flow protocols, seasonal contracts, data sharing
Fuel	Gas constraints during the fall and winter reduce available capacity.	High	Fuel planning, flexible units, emergency support protocols
Grid delays	Transmission lines are commissioned later than RE sources, demand, and external commitments.	High	P1 projects, project preparation mechanism, feasibility studies, IFI portfolio
Insufficient digital readiness	Incomplete telemetry and varying accounting methods undermine confidence in calculations.	High	Data management regulations, settlement metering, PMU, unified reporting
Unverified RE/BESS models	Incorrect inverter behavior during faults and increased risk of outages	High	Verification of RMS/EMT models, compliance testing, post-fault analysis
Payment discipline	Non-payments undermine confidence in DAM, curtailment, and ancillary services.	High	Guarantees, escrow accounts, letters of credit, netting, default coverage fund
Cybersecurity	Threats to SCADA, smart metering, market platforms, and data channels	High	Secure channels, cybersecurity standards, incident response
Market power	Major participants or bottlenecks affect price and access to transmission capacity.	Medium/High	Market monitoring, transparency, rules against withholding of generation or transmission capacity
Water disputes	Conflicting water and energy interests	High	Basin water organizations, intergovernmental agreements and protocols, payment for hydropower flexibility, dispute resolution mechanism

Risk	How it manifests	Impact	Mitigation measures
Tariff acceptability	Investments and payments for capacity availability increase tariff pressure	High	Phased implementation, targeted support, distribution of benefits
Currency risk	Capital expenditures and PPAs are denominated in foreign currency, while tariffs are set in local currencies.	Medium/High	Currency risk hedging, IFI guarantees, indexation rules
ESG and land issues	Power lines, substations, cables, and hydropower plants require ESIA and stakeholder engagement.	Medium	ESIA, stakeholder engagement, compensation plans
External corridors	Confirmed buyer, security, transit, and synchronization affect bankability.	High	Preliminary feasibility study, phased approach, risk allocation
Green electricity certification	Uncoordinated guarantees of origin reduce the value of green exports.	Medium/High	Register of guarantees of origin, additionality rules, audit trail, volume matching rules
Institutional delay	Market rules are not keeping pace with the grid, RE, and external projects.	High	Political mandate, REMIT roadmap, regular monitoring, mechanism for amending rules

Sources: Compiled by EDB experts based on [IEA \(2024\)](#), [OECD \(2025\)](#), [ENTSO-E Expert Panel \(2026\)](#), [ESMAP \(2026\)](#), and REMIT.

CONCLUSION

Central Asia already possesses assets that many regions have spent decades building: interconnected power systems, experience with cross-border flows, seasonal resource complementarity, and an institutional memory of parallel operation. Those advantages are no longer sufficient on their own. Rising demand, aging assets, tight reserve margins, rapid renewable deployment, water-energy constraints, and external corridors are changing the nature of the regional power agenda. The question is no longer whether the systems are connected, but whether that connectivity can be reliable, controllable, financially sustainable, and acceptable to all participants.

Regional cooperation is not a substitute for national energy security; it is one of its instruments. Governments and national operators remain responsible for domestic system operation, tariffs, security of supply, and investment. But a growing share of power-sector risks is inherently regional: shortages propagate across borders, transmission constraints reduce the value of new generation, inadequate reserves increase outage risk, and poorly coordinated water-energy operation erodes the value of hydropower. Stronger national energy security therefore increasingly depends on stronger regional coordination.

The economic value of integration extends well beyond the sale of electricity across a border. The region can use its assets as a shared reliability portfolio: grids deliver capacity, hydropower provides flexibility, digital infrastructure creates trust in data, market rules allocate responsibility, and investment removes specific system constraints. This changes project appraisal. Value should be measured not only by physical asset parameters, but also by additional transfer capability, avoided shortages, lower curtailment of RE, stronger settlement discipline, and greater future trading opportunities.

Central Asia should avoid two extremes. The first is to preserve integration largely through informal and ad hoc arrangements in which physical flows exist but economic value, risk, and responsibility remain opaque. The second is to introduce sophisticated market mechanisms before grids, metering, data, payment discipline, and institutions are ready. A more durable sequence moves from operational transparency and settlement discipline to short-term trading, then balancing and ancillary services, and finally regional resource adequacy and longer-term reliability instruments. This sequence also follows the economics: in the central case, the additional benefit per dollar of additional cost falls from about 2.6 for partial integration to about 1.0 for deeper integration and about 0.7 for the advanced architecture ([Chapter 5](#)).

Political economy is central to implementation. A project may generate positive net benefits for the CAPS while distributing those benefits unevenly: one country may reduce shortages, another earn transit revenue, another receive remuneration for flexibility, and another lower curtailment of RE. Regional architecture therefore needs explicit rules for benefit sharing, cost allocation, imbalance settlement, payment security, and dispute resolution alongside the physical and digital infrastructure. This is the practical meaning of “an architecture of trust.”

The water–energy nexus makes this particularly sensitive. Hydropower in Kyrgyzstan and Tajikistan can provide some of the region’s most valuable low-carbon flexibility, but it cannot be treated as a free reserve for neighboring systems. Water carries energy, irrigation, environmental, social, and interstate value. A mature regional model must therefore remunerate hydropower flexibility as a measurable service, while respecting water-management obligations and the interests of both upstream and downstream countries.

The development of external energy corridors underscores the importance of internal controllability within the CAPS. The southern, northern, eastern, western, and southwestern directions open up various opportunities: exports, reserve capacity, access to new markets, technological integration, and diversification of partnerships. However, external connections cannot compensate for the weakness of the internal core. Without robust grids, digital monitoring, settlement discipline, water–energy coordination, and transparent business models, external corridors will compete for the region’s limited resources. With a well-developed internal infrastructure, on the other hand, they can serve as an extension of modernization and a source of additional investment value.

In line with Strategy 9 of ESCAP’s Regional Road Map, regional power-connectivity projects should be assessed not only by their technical and economic outcomes, but also by their contribution to sustainable development. Project-selection criteria should therefore include energy security, energy affordability, RE integration, climate resilience, environmental and social impacts, and the equitable allocation of costs and benefits.

The report’s central conclusion is that Central Asia should convert inherited interconnection into a managed regional asset. Doing so requires continuous observability, disciplined system operation, coordinated rules, clear allocation of responsibilities, and an investment strategy focused on measurable system-wide benefits. Integration does not imply surrendering national control. Properly designed, it strengthens national energy security by giving each country access to a broader portfolio of resources, reserves, networks, and reliability instruments.

The proposed approach is deliberately incremental. It does not require the immediate creation of a fully fledged regional market or the replacement of national market models. Each step is conditional on the verifiable readiness of the previous one: data, settlement metering, schedules, accountability, available transfer capacity, payment security, balancing, ancillary services, and long-term resource adequacy. This reduces the risk of premature reform and allows countries to progress at different speeds, while preserving a common direction.

For the Eurasian Development Bank, this agenda translates directly into project opportunities. Regional cooperation creates investments whose benefits cross borders and therefore require system analysis, project preparation, benefit-sharing arrangements, comparable KPIs, and financing structures that recognize regional value. The EDB can bridge technical diagnosis, economic appraisal, project preparation, financing, and intergovernmental dialogue. In practical terms, this could include

financing project preparation (feasibility studies, ESIA, and system studies) for the P1–P2 grid packages in [Table 23](#); co-financing priority interconnections and the digital package (the AGC Coordination Center, WAMS/WACS, and secure communications) alongside REMIT; and supporting the design of benefit-sharing and payment-security mechanisms, including, where eligible, through the Eurasian Fund for Stabilization and Development managed by the EDB.

Central Asia can either preserve connectivity as a limited set of transmission lines, emergency protocols, and bilateral arrangements, or develop it into the foundation of a modern regional power architecture. The second path is more demanding, but it offers the stronger route to higher reliability, lower total system costs, deeper renewable integration, monetized hydropower flexibility, and more sustainable participation in external power markets. Managed regional connectivity is therefore not an end in itself; it is an enabling condition for the next stage of Central Asia’s power-sector development.

APPENDIX A.

ASSUMPTIONS REGARDING EXISTING AND ADDITIONAL CAPACITY

The CAPS lacks a single published regional ATC indicator that could be used directly as a baseline. It is incorrect to sum the allowable power flows of individual monitored transmission interfaces, since many of them overlap, belong to the same transmission chain, and cannot be operated at full capacity simultaneously. With the operating conditions under consideration, the allowable power flows through individual critical sections range primarily from 0.8 to 2.8 GW; moreover, during the 2024/25 winter operating period, a number of sections were already operating at or above their allowable limits.

Therefore, the equivalent utilized transfer capacity is used to calibrate the scenarios. It is determined by converting the actual volume of regional trade in 2024—12.1 billion kWh—into nominal capacity, taking into account 5,500–6,500 hours of grid usage and losses of approximately 6%. The resulting range is 2.0–2.3 GW, with a central value of approximately 2.15 GW. This is the calculated energy equivalent of the observed trade volume, not an engineering estimate of the CAPS's transmission capacity. It is not a TTC, NTC, or ATC and cannot be used to assess the physical feasibility of power transmission over a specific transmission line section.

The REMIT indicator (up to 16 GW) refers to the total rated capacity of interconnections (TTC) and is not directly comparable to the equivalent utilized transfer capacity (2.0–2.3 GW) used in the report to calibrate the scenarios: the gap between them reflects precisely the operational and digital controllability that this report aims to enhance.

The additional trading volume is calculated as follows:

$$\Delta E_s = \Delta ATC_s \times H_s \times k_s^{use} \times (1 - L_s)$$

where:

ΔATC_s denotes the increase in effectively available capacity;

H_s amounts to approximately 6,000 hours per year;

k_s^{use} reflects the dispatchers' utilization of the available resource;

L_s takes network losses into account (6%).

Partial Integration Scenario

The partial integration scenario assumes an increase in the effectively available transmission capacity of the CAPS's interconnections by 1.0 GW—from 2.15 to approximately 3.15 GW. This increase is achieved without constructing a full set of large interconnection lines and is realized through a combination of digital, operational, and local physical measures.

It is of fundamental importance that the four components of the increase differ not only in magnitude, but also in terms of their availability. Part of the increase is fixed and is constantly present in the system; the other part is contingent and is realized only under favorable grid conditions. This distinction determines both the reliability of the estimate and the subsequent conversion of capacity into energy.

Conditional (operating-mode-dependent) component (0.6–0.7 GW)

0.25 GW — digital control and refinement of stability limits. Implementation of WAMS/WACS, expansion of the PMU network, improvement of the emergency control system, and transition from conservative deterministic limits to calculated estimates that take into account the actual state of the system. The improvement is observed under full-network conditions and normal system operation; in maintenance configurations and under severe operating conditions, the limits revert to conservative values.

0.20–0.25 GW — coordination of maintenance, topology optimization, and coordinated NTC/ATC calculations. Synchronization of maintenance campaigns among national operators, optimization of the grid configuration, and a transition from separate to coordinated determination of the transmission capacity of monitored transmission interfaces. The gain depends on the degree of institutional coordination and is lost when maintenance schedules are out of sync.

0.15–0.20 GW — AGC, reserve coordination, and lower operational uncertainty. Automatic generation control, mutual recognition of reserves, and improved forecasting can reduce the margin held against uncertainty. The benefit is available only where dispatch centers have effective coordination arrangements and participating units are technically capable of following AGC signals.

Hard (physical) component (0.35–0.45 GW)

Local grid reinforcements. Substation upgrades, transformer replacements, installation of reactive power compensation equipment, modernization of protection systems, and upgrades to individual sections of power lines. The increase is sustained and decreases only when equipment is undergoing maintenance.

The total range is 0.95–1.15 GW; 1.0 GW is taken as the central estimate.

Based on the central assumption of a 1 GW increase in equivalent utilized transfer capacity, its energy equivalent is approximately 4.8 billion kWh per year (6,000 hours of utilization, an 85% utilization rate, and 6% losses). Part of this increase is achieved through operating-mode-dependent digital and operational measures, the availability

of which varies depending on the grid configuration, maintenance schedules, and the condition of the power systems. A conservative estimate using separate utilization factors for physical and operating-mode-dependent gains yields 2.3–3.1 billion kWh per year. Refining this estimate requires an hourly analysis of the alignment between export capacity, import demand, and available directed transmission capacity.

Deeper Integration Scenario

The total increase in equivalent utilized transfer capacity is assumed to be 1.88 GW, bringing the total to approximately 4.0 GW relative to the existing base. In addition to the digital and operational measures outlined in the first scenario, an additional effect of approximately 0.8–1.0 GW is factored in from priority physical upgrades:

- Kristall–Yulduz;
- Frunze–Kemin;
- the second Shymkent–Tashkent TPP transmission line or an alternative Murantau–Shymkent configuration;
- reconstruction of critical substations;
- removal of constraints within the Fergana power hub;
- strengthening of internal corridors that limit cross-border power flows.

The Shymkent–Tashkent TPP and Murantau–Shymkent projects should be considered as alternative or complementary options for alleviating a single set of constraints, rather than automatically being added together.

The 1.88 GW increase corresponds to approximately 9.0 billion kWh of additional annual trade.

Advanced Regional Architecture Scenario

The total increase in effectively available capacity is estimated at 2.75 GW, bringing the total to approximately 4.9 GW. The additional benefit relative to the “deeper” scenario stems from:

- Kemin–Almaty;
- Datka–Sughd in transit mode and the strengthening of northern Tajikistan;
- further strengthening of ties between Uzbekistan and Tajikistan;
- strengthening the Turkmen route;
- full regional coverage of WAMS/WACS and AGC;
- DAM and RTM, which allow for the redistribution of ATC among routes and time slots;
- coordinated use of reserves and corrective control actions.

The 2.75 GW increase corresponds to approximately 13.2 billion kWh of additional trade per year.

↓ Table 35. Assumptions for Scenarios of Increased Regional Trade

Indicator	Partial integration	Deeper integration	Advanced architecture
Additional trade, billion kWh	4.8	9.0	13.2
Net trading spread, \$/MWh	5–18	5–18	5–18
Cost of retained RE generation, \$/MWh	15–35	15–35	15–35
Avoided curtailment, billion kWh	0.9	2.2	3.5

Source: EDB expert estimates.

Thus, the scenario volumes of 4.8, 9.0, and 13.2 billion kWh represent the energy equivalent of utilized transmission capacity, rather than the difference between annual surpluses and deficits. Country balances are used solely to verify the availability of resources and demand. The actual ATC increment for each project must be verified by steady-state, N-1, dynamic stability, and cascade constraint analyses.

APPENDIX B.

METHODOLOGY FOR SCENARIO-BASED ASSESSMENT OF THE ECONOMIC BENEFITS OF INTEGRATION

This appendix details the assumptions, sources of parameters, and calculation methods used in [Chapter 5](#). This assessment is a preliminary analysis intended to determine the order of magnitude of the potential effect. All monetary figures are expressed in U.S. dollars at constant 2026 prices and refer to a steady-state annual regime following the implementation of the relevant package of measures. Taxes, subsidies, and other intra-regional transfers are not considered net economic benefits.

B.1. Baseline Scenario

The baseline scenario describes the development of power systems through 2030 based on the implementation of national plans and projects that have already been adopted, but without the additional regional grid reinforcements, digital platforms, and market mechanisms envisaged in the integration scenarios. The actual trade volume for 2024 is used to calibrate the existing equivalent utilized transfer capacity, but is not interpreted as a fixed forecast for 2030. Benefits are calculated as the difference between the integration and baseline scenarios under identical assumptions regarding demand, fuel, hydrology, and new generation capacity.

↓ Table 36. Baseline Scenario and Levels of Regional Integration

Scenario	Network and digital configuration	Market configuration	Increase in effectively available capacity, GW	Additional trade, billion kWh/year
2030 Baseline scenario	Approved national projects; existing constraints on domestic and cross-border transmission capacity	Bilateral contracts and existing procedures	0	0
Partial integration	WAMS/WACS, AGC, settlement metering, maintenance coordination, local reinforcements	Formalized schedules, deviations, emergency and balancing power	0.7–1.2	3.5–6.0
Deeper integration	Priority lines and substations, removal of some internal constraints	“Day-Ahead” pilot market, payment guarantees, limited set of ancillary services	1.5–2.2	7–11
Advanced architecture	Comprehensive reinforcement of internal and inter-system corridors, fully digital loop	DAM/RTM, balancing, ancillary services, and reserve sharing	2.2–3.3	10.5–16

Source: EDB experts’ scenario assumptions and calculations.

B.2. Parameters and Data Sources

The parameters are specified as ranges because there is no single set of public hourly data covering all power systems in the region. The lower bounds reflect limited realization of trading and reliability benefits, while the upper bounds reflect fuller utilization of the grid and coordinated rules. The ranges are not independent: coordinated combinations of assumptions are used when deriving the final assessment. Price and capital parameters are calibrated, where possible, against competitive RE procurements and new thermal generation projects in Central Asia, while international indicators are used only to verify the order of magnitude.

↓ **Table 37. Key Parameters of the Scenario Assessment**

Parameter	Working range	Source/Method
Regional trade in 2024	12.1 billion kWh	CDC Energia; national balances
Equivalent utilized transfer capacity	2.0–2.3 GW	Back-calculation based on trade, hours of use, and losses
Hours of use	5,500–6,500 hours	EDB scenario assumption
Transmission losses	6%	Technical assumption for the inter-system chain
Net trading spread	\$5–18/MWh	Difference between avoided and incremental variable costs
Reliable contribution from cross-border resources	0.3–2.2 GW	Share of ATC increase, accounting for peak overlap and N-1
Annualized cost of firm capacity	\$80–185/kW-year	CAPEX: \$700–1,800/kW; 8%; 25 years; fixed O&M ≈ \$15/kW-year
Potential regional curtailment of RE	5.4–7.2 billion kWh/year	Forecast for Uzbekistan and scaling by country
Avoided curtailment	0.6–4.5 billion kWh/year	Share of curtailment mitigated by grids and balancing
Value of preserved RE generation	\$15–35/MWh	Conservative resource cost
Cost of stress energy	\$150–350/MWh	Emergency imports, rescheduling, and risk of shortfall
Discount rate and time horizon	8–10%; 20–25 years	EDB scenario assumption
Annualized integration costs	\$50–750 million/year	Portfolio of grid, digital, and institutional measures

Sources: Compiled by EDB experts based on data from CDC Energia, national plans, international benchmarks, and the report's project portfolio.

B.3. Calculation Formulas

Total Net Effect:

$$NB_s = B_s^{trade} + B_s^{capacity} + B_s^{curt} + B_s^{reliability} - C_s^{integration}$$

The four groups of benefits are evaluated separately and then reduced by the annualized integration costs.

Equivalent existing transmission capacity:

$$ATC^{eq} = \frac{E^{trade}}{H \times k^{use} \times (1 - L)}$$

This metric is used solely to calibrate the existing baseline based on actual trade volumes.

Additional trade volume:

$$\Delta E_s = \Delta ATC_s \times H_s \times k_s^{use} \times (1 - L_s)$$

The increase in ATC is converted to an annual volume, taking into account hours of use, actual dispatch execution, and losses.

Operating savings:

$$B_s^{trade} = \Delta E_s \times \Delta MC_s^{net}$$

The net spread accounts for the importer's avoided costs, net of the exporter's variable costs, losses, and transmission costs.

Avoided capacity investments:

$$B_s^{capacity} = P_s^{avoided} \times AC^{firm}$$

Only reliably available and grid-deliverable capacity confirmed for peak hours is taken into account.

Effect of reducing curtailment of RE:

$$B_s^{curt} = E_s^{curt,avoided} \times V^{RE}$$

Only that portion of curtailments that can be eliminated through regional coordination and grid reinforcements is assessed.

Reliability effect:

$$B_s^{reliability} = P_s^{support} \times H_s^{stress} \times k_s^{availability} \times V_s^{stress}$$

Includes variable costs under stress scenarios; the cost of building reserve capacity is accounted for separately.

Annualized integration costs:

$$C_s^{integration} = CAPEX_s \times CRF(r, n) \times FOM_s \times C_s^{digital} \times C_s^{market} \times C_s^{security}$$

CAPEX is annualized using the capital recovery factor (CRF), and then operating and institutional costs are added.

$$NPV_s = \sum_{t=0}^n \frac{B_{s,t} - C_{s,t}}{(1+r)^t}$$

For project analysis, benefits and costs are calculated on an annual basis, taking into account the construction schedule and the gradual realization of benefits. For the screening in [Chapter 5](#), lifetime equivalents are calculated as annuities: the present value equals the annual central-case effect multiplied by the annuity factor $(1 - (1+r)^{-n}) / r$, which is about 10.7 for $r = 8\%$ and $n = 25$ years and about 8.5 for $r = 10\%$ and $n = 20$ years ([Table 38b](#)).

The calculated volume cannot exceed the simultaneously available export capacity, import demand, and the physical capacity of the grid.

B.4. Sensitivity Analysis

[Chapter 5](#) reports central-case values (the midpoints of the ranges) and a favorable case. The sensitivities based on varying key parameters, the stress cases, and the lifetime equivalents are presented below ([Tables 38a](#) and [38b](#)). Both single-parameter and combined stress tests are necessary for making an investment decision. The actual benefit realization factor is of particular importance: a technically available network does not produce its full effect if administrative restrictions, non-payments, opaque ATC/NTC calculations, or insufficient coordination of system operation persist.

↓ **Table 38. Sensitivity Analysis Framework**

Parameter	Conservative check	Main range	Upper-bound test
Additional trade	2.3–3.1 billion kWh per 1 GW (35–50% below the main range)	Ranges in Table 7	10–15% above the upper bound with confirmed ATC
Net trading spread	25% below	\$5–18/MWh	25% higher
Reliable capacity contribution	30% lower	0.3–2.2 GW	20% higher with confirmed ELCC
Avoided curtailment	30% lower	0.6–4.5 billion kWh	20% higher with grid reinforcement
CAPEX and annual costs	30% higher	Ranges in Chapter 5	15% lower
Actual realization of gross benefits	70%	85%	100%
Discount rate	10%	8–10%	8%

Source: EDB experts' assumptions.

The lower and upper gross estimates correspond to consistent low- and high-realization cases rather than to independent combinations of parameters. Trade growth, the reduction of curtailment of RE, and the contribution of cross-border capacity are correlated through common drivers: grid condition, digital observability, market rules, and payment discipline. An internally consistent set of assumptions is applied for each scenario. Net-effect extremes that pair the lowest benefits with the highest costs (Table 38a) are stress cases rather than scenarios.

Sensitivity of the net effect. Table 38a shows how the annual central-case net effect responds to lower benefit realization and to extreme combinations of benefits and costs. Partial integration remains positive in almost all cases and needs about 40% of the central gross effect to cover its costs; deeper integration needs about 70%; and the advanced architecture needs about 94%, which is why its central-case result is close to break-even and why it should follow, not precede, the demonstration of results under the earlier phases.

↓ Table 38a. Sensitivity of the Annual Net Effect, millions of dollars per year

Case	Partial integration	Deeper integration	Advanced regional architecture
Central case	118	123	40
Benefits 25% below central (central costs)	70	25	-120
Benefits 50% below central (central costs)	20	-75	-280
Favorable case (highest benefits, lowest costs)	270	450	580
Stress case (lowest benefits, highest costs)	-35	-205	-500
Benefit realization needed to break even, % of central gross effect	39%	69%	94%

Source: EDB experts' calculations.

Note: The favorable case combines the upper benefit bounds with the lower cost bounds. The stress case combines the lower benefit bounds with the upper cost bounds; it is an extreme combination, not a forecast. Break-even benefit realization is the share of the central gross effect needed to cover the central annualized costs. Costs are counted for the full integration portfolio. To the extent that some components, such as internal grid reinforcements, would be required under national plans in any case, only their integration-attributable share belongs in this comparison, but the benefits linked to those components would then also be partly attributable to the baseline. Such attribution requires project-level CAPEX data and is left to the next modeling phase (Appendix B.7).

Lifetime equivalents. The values in Chapter 5 are annual flows, not cumulative or lifetime amounts. Table 38b converts the central case into lifetime equivalents over a 25-year horizon at an 8% discount rate, the same assumptions used to annualize costs. The present value of net benefits is about USD 1.3 billion for both partial and deeper integration and about USD 0.4 billion for the advanced architecture; undiscounted, net benefits over 25 years are about USD 3.0, 3.1, and 1.0 billion, respectively. The lifetime view reinforces the sequencing: if benefits build up gradually over five years rather than starting at the full level, the present value of the advanced architecture turns negative (about USD -0.7 billion), while partial and deeper integration remain positive (about USD 0.9 billion and USD 0.6 billion).

↓ Table 38b. Lifetime Equivalents of the Central-Case Effect, billions of dollars

Indicator	Partial integration	Deeper integration	Advanced regional architecture
Present value of gross benefits (8%, 25 years)	2.1	4.2	6.8
Present value of annualized integration costs (8%, 25 years)	0.8	2.9	6.4
Present value of net benefits (8%, 25 years)	1.3	1.3	0.4
Present value of net benefits (10%, 20 years)	1.0	1.0	0.3
Present value of net benefits with a five-year ramp-up of benefits (8%, 25 years)	0.9	0.6	-0.7
Undiscounted net benefits over 25 years	3.0	3.1	1.0

Source: EDB experts' calculations.

Note: Present values equal the central-case annual values multiplied by the annuity factor (about 10.7 for 8% and 25 years; about 8.5 for 10% and 20 years). Because costs are annualized at the same discount rate and horizon, the present value of costs approximates capital outlays plus operating costs over the horizon. The calculation does not include growth in benefits, inflation, residual value, or differences in asset lifetimes (digital systems are shorter-lived and transmission lines longer-lived). The ramp-up case assumes that benefits rise linearly from 20% to 100% of the central level over the first five years, while costs are unchanged.

B.5. Checking for Double Counting and Accounting for Transfers

↓ Table 39. Rules for Allocating Economic Effects

Potential Intersection	Accounting Rule
Operating savings and avoided capacity investments	The trading spread includes only variable costs; the capital and fixed costs of reliable capacity are accounted for separately.
Operating savings and reliability benefits	Emergency and stress power are included in the reliability benefit only to the extent not accounted for in the standard trading spread.
Trading and reduction of curtailment of RE	The same MWh is not counted simultaneously at both the full value of saved generation and the full trading spread. If the energy is sold, the trading benefit is calculated as an additional net spread beyond the already accounted-for value of the RE.
Reserve capacity and emergency support	The cost of building reserve capacity is attributed to the capacity benefit; the variable costs of its use are attributed to the reliability benefit.
Transit tariffs, congestion rent, and payments for ancillary services	Payments between participants in a region represent a distribution of the effect, not an additional net benefit. The net effect includes actual costs, losses, and investments.
Climate impact	Emissions reductions are expressed in physical units and are not monetized in the baseline benefit amount if the cost of carbon is already reflected in marginal costs.
Taxes, subsidies, and government transfers	These are excluded from the regional net effect but are taken into account when distributing benefits among countries and analyzing fiscal implications.

Source: EDB experts' methodological framework.

B.6. Conditions for Revising the Scenario-Based Assessment

The scenario assessment must be revised if one or more of the following conditions are met: a sustained deviation of actual net spreads from the range of \$5–18/MWh by more than 30%; a deviation of actual RE and BESS capacity additions in Uzbekistan and Kazakhstan by more than 20% from the projections used; a delay of more than two years in priority P1 grid projects; an actual increase in ATC following digital and grid measures that differs by more than 20% from the scenario; the capital intensity of new CCGTs or grid facilities exceeding accepted regional ranges; or a significant change in the institutional status or funding of REMIT. The review should include updating the baseline data, recalibrating prices and costs, and verifying the distribution of benefits across countries.

B.7. Requirements for the Next Simulation Phase

To move from a preliminary screening assessment to project-level analysis, a unified hourly CAPS model is required, incorporating unit commitment, hydrological scenarios, VRE, BESS, forced-outage rates, internal and cross-border transmission constraints, and probabilistic adequacy metrics including LOLE, EENS, and ELCC. The modeling package should include a dated source-data register, machine-readable scenario assumptions, the methodology for determining trade and ATC, project-level CAPEX, sensitivity results, and the distribution of benefits by country. Independent technical validation should be completed before results are used for government commitments, tariff decisions, or investment approval.

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ABBREVIATIONS

ADB	Asian Development Bank
AGC	Automatic Generation Control
ATC	Available Transfer Capacity
BESS	Battery Energy Storage System
BWO	Basin Water Organization
CAPEX	Capital Expenditure
CAPS	Central Asia Power System
CCGT	combined-cycle gas turbine
CDC Enerгия	Coordinating Dispatch Center Enerгия
CEPC CA	Coordinating Electric Power Council of Central Asia
DAM	Day-Ahead Market
DC	direct current
EAEU	Eurasian Economic Union
EDB	Eurasian Development Bank
EENS	Expected Energy Not Served
ELCC	Effective Load Carrying Capability
GT	gas turbine unit
GWh	gigawatt-hour
HPP	hydropower plant
HVDC	High-Voltage Direct Current
KEGOC JSC	Kazakhstan Electricity Grid Operating Company
KPI	key performance indicator
kWh	kilowatt-hour
LOLE	Loss of Load Expectation
MW	megawatt
MWh	megawatt-hour
NEPS	Northeast Power System, Afghanistan
NSO	national system operator
NTC	Net Transfer Capacity
OHL	overhead transmission line
PMU	Phasor Measurement Unit
PSHPP	pumped-storage hydropower plant
REMIT	Regional Electricity Market Interconnectivity and Trade
RES	renewable energy sources
RGE	reciprocating gas engine
RTM	Real-Time Market
SCADA	Supervisory Control and Data Acquisition
SPP	solar PV plant
SS	substation
TPP	thermal power plant
TRM	Transmission Reliability Margin
TTC	Total Transfer Capacity
UES	Unified Energy System
USD	U.S. dollar
VRE	variable renewable energy
WACS	Wide-Area Control System
WAMS	Wide-Area Monitoring System

GLOSSARY

Additionality	Extent to which a claim or transaction supports renewable generation beyond what would otherwise occur.
AGC	Automatic Generation Control; automated control of frequency and scheduled interchange through participating generating units.
Availability	Ability of a resource to be in service and capable of delivering its committed output when required.
Back-to-back HVDC (B2B)	Controllable HVDC interconnection between asynchronous AC systems without a long DC transmission line.
Bankability	Ability of a project or contractual structure to attract financing on acceptable terms.
Benefit sharing	Allocation of project or integration benefits among participating countries or entities.
Capacity mechanism	Market or administrative mechanism that remunerates dependable capacity or other contributions to long-term reliability.
Central Asia Power System (CAPS)	Regional synchronous power system linking Uzbekistan, Kyrgyzstan, Tajikistan, and southern Kazakhstan; selected external units connect in islanded configurations.
Collateral	Assets, cash, guarantees, or other security provided against contractual obligations.
Cost allocation	Allocation of investment and operating costs among participating countries or entities.
Curtailement	Forced reduction of available generation below its unconstrained output because of system, grid, or market constraints.
Default fund	Fund used to cover defined settlement shortfalls or participant defaults.
Deliverability	Ability of the transmission grid to deliver a resource to the relevant load area under defined security criteria.
Dispute resolution	Formal process for resolving contractual, operational, or market disputes.
EENS	Expected Energy Not Served; expected volume of electricity demand that cannot be supplied.
ELCC	Effective Load Carrying Capability; the contribution of a resource to resource adequacy.
Escrow account	Account in which funds are held subject to predefined release conditions.
ESIA	Environmental and Social Impact Assessment.
Feasibility Study (FS)	Detailed technical, economic, environmental, and financial assessment of a proposed project.
Firm capacity	Capacity that can be relied upon under defined system conditions.
FX hedging	Financial or contractual mitigation of foreign-exchange risk.
Green Energy Corridor	Transmission and market arrangement enabling trade in electricity meeting defined green attributes.
Grid code	Technical rules governing connection and operation of generation, networks, storage, and other power-system users.
Guarantee of Origin (GO)	Certificate tracking the renewable origin of electricity.
Hydropower flexibility	Ability of hydropower to adjust output, provide reserves, shift energy across time, and support system balancing subject to water constraints.
HVDC	High-Voltage Direct Current transmission.
Letter of credit (LC)	Bank instrument supporting payment obligations under specified conditions.

Additionality	Extent to which a claim or transaction supports renewable generation beyond what would otherwise occur.
LOLE	Loss of Load Expectation; expected frequency or duration of periods in which resources are insufficient to meet demand.
Market monitoring	Oversight of market conduct, concentration, bidding behavior, and potential manipulation.
Market power	Ability of a market participant to influence prices or market outcomes materially.
Middle Path	EDB framework balancing reliability, energy affordability, and environmental sustainability.
Netting	Offsetting reciprocal payment obligations to arrive at a net settlement amount.
Offtake / offtaker	Offtake: contracted purchase arrangement; offtaker: purchasing counterparty.
Opportunity cost	Value of the best alternative use forgone when a resource is committed to a particular service.
Payment security	Contractual and financial arrangements that reduce settlement and counterparty risk.
PMU	Phasor Measurement Unit, providing time-synchronized voltage and current phasors.
Pre-Feasibility Study (Pre-FS)	Early-stage assessment used to screen project options before a full feasibility study.
Ramping	Ability of a resource to change active-power output over time.
Reliability options	Contracts that remunerate dependable capacity while imposing settlement obligations during scarcity conditions.
Resource adequacy	Ability of a power system to meet demand with an acceptable reliability level, accounting for outages, variability, fuel and water constraints, storage, imports, and grid deliverability.
Ring-fenced approach	Organizationally, financially, or operationally segregated arrangement designed to isolate specific functions or risks.
Risk register	Structured record of material risks, impacts, owners, and mitigation measures.
Settlement metering	Revenue-grade metering used for commercial settlement of cross-border flows and imbalances.
Stakeholder engagement	Structured consultation and communication with affected and interested parties.
Stranded assets	Assets at risk of underutilization, impairment, or early retirement because of changing market, policy, or system conditions.
Take-or-pay	Contractual payment obligation that may apply irrespective of actual consumption or dispatch, subject to the specific contract terms.
WACS	Wide-Area Control System for coordinated wide-area corrective actions.
WAMS	Wide-Area Monitoring System using synchronized phasor measurements.
Wear and tear	Incremental equipment degradation associated with operation, cycling, starts, stops, or frequent output changes.
Wheeling charges	Charges for use of a third-party transmission network.



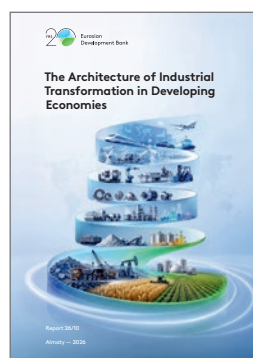
Research at the EDB website



Macroeconomic Outlook (RU/EN)

Macroeconomic Outlook 2026–2028

The analysis reviews economic development of the Bank's member states in early 2026 and outlines key macroeconomic forecasts for late 2026 and for 2027–2028.



Report 26/10 (RU/EN)

The Architecture of Industrial Transformation in Developing Economies

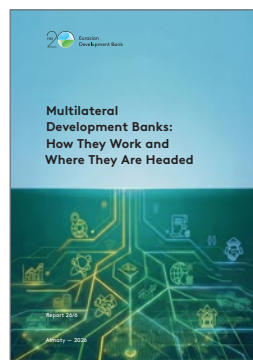
Based on global experience and the approaches of leading institutions, using the Eurasian region as an example, a modular three-stage architecture for industrial development is proposed: from a basic manufacturing foundation through an industrial platform to a knowledge economy and technological sophistication. This flexible toolkit is applicable to most developing economies.



Report 26/9 (RU/EN)

Transport Corridors Infrastructure: The Observatory and an Interactive Map of Eurasian Transport Network Projects — 2026

This Working paper presents the results of a review of investment in the development of transport corridors in the Eurasian region in 2025, as well as an analysis of projects under implementation or in the planning stage for the period up to 2035. The report provides an assessment of China's involvement in the development of transport infrastructure in Central Asia.



Report 26/6 (RU/EN)

Multilateral Development Banks: How They Work and Where They Are Headed

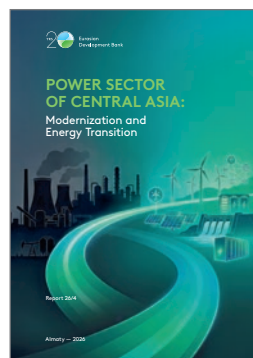
This report is the first comprehensive 'encyclopedia' of the MDB system. It examines the criteria for classifying institutions as MDBs, their formation stages, geographic scope of operations, governance structures, mandates, instruments, key performance indicators, and the system's development outlook for the next decade.



Report 26/5 (RU/EN)

Waves of Investment Megahype. Digital, ESG, AI: What's Next?

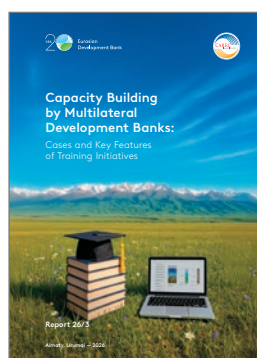
The report analyzes technological investment booms and potential new waves over a 20-year horizon: biotech, robotics, space, VR, energy storage, and climate adaptation. Special focus is placed on investments in biotech and longevity as a response to labor market challenges.



Report 26/4 (RU/EN)

Power Sector of Central Asia: Modernization and Energy Transition

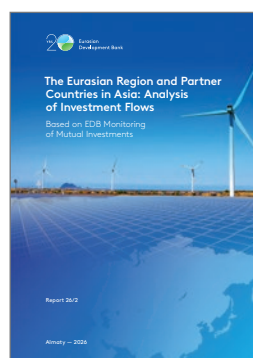
How can Central Asia secure a reliable and clean energy future? The answer lies in the «Middle Path» strategy. The report substantiates a balanced modernization model, integrating renewable energy potential with the stability of traditional generation and the synergies of regional cooperation.



Report 26/3 (RU/EN)

Capacity Building by Multilateral Development Banks: Cases and Key Features of Training Initiatives

The report provides an overview of MDBs training initiatives (academies, institutes, training programs), analyzes their goals, governance and financing models, thematic areas, and other characteristics, outlines the long-term outlook for the development of the MDB training initiatives.



Report 26/2 (RU/EN)

The Eurasian Region and Partner Countries in Asia: Analysis of Investment Flows based on EDB Monitoring of Mutual Investments

The report provides detailed information on the scale, dynamics, geographical and sectoral structure of mutual foreign direct investment stock between Asian countries and countries in the Eurasian region for the period from 2016 to the first half of 2025.



Report 26/1 (RU/EN)

Cooperation of Multilateral Development Banks in Emerging Markets and Developing Countries: Untapped Opportunities

The report examines seven promising areas for MDB cooperation: 1) mobilizing capital, 2) capital markets, 3) local currencies, 4) project expertise, 5) pooling knowledge, 6) technical assistance, 7) cross-border projects.



Report 25/15 (RU/EN)

China and the Eurasian Region: Analysis of Investment flows based on EDB Monitoring of Mutual Investments

The report provides detailed information on the scale, dynamics, geographical and sectoral structure of mutual foreign direct investment stock between China and countries in the Eurasian region for the period from 2016 to the first half of 2025.



Report 25/14 (RU/EN)

Investment Cooperation in the Eurasian Region based on EDB Monitoring of Mutual Investments

The report provides comprehensive insights into the scale, dynamics, geographical and sectoral structure of mutual foreign direct investments in the Eurasian region from 2016 to the first half of 2025, as well as key trends in investment cooperation.



Working Paper 25/13 (RU)

Arab Gulf: Macroeconomic and Financial Monitoring

The EDB's monitoring provides an analysis of the economies of six Gulf countries and assesses medium-term trends, including GDP growth, inflation, debt sustainability, and fiscal and monetary policies.



Report 25/12 (RU/EN)

Warehouse Infrastructure in Eurasia: Opportunity of the Decade

The report presents an analysis of the current state of the warehouse logistics and storage sector in the Eurasian region, examines the main factors influencing its development, and provides a detailed forecast of demand for warehouse infrastructure in the region up to 2040.



Report 25/11 (RU/EN)

Advanced Manufacturing Potential in Eurasia: Sectoral Niches for Growth

The transition to high value-added production could become a powerful driver of economic growth in the region. The study identifies priority industries and niche markets for each country, and provides estimates of export potential and import substitution potential.



Working Paper 25/9 (RU/EN)

The Middle-Income Trap: Navigating the Ambiguity of the Concept

The study shows that diversity of interpretations of the "middle-income trap" makes it difficult to understand whether an economy is in it. The paper also identifies the factors of transition to a higher income: stable macroeconomics, ability to innovate, strong institutions and demographics.



Report 25/8 (RU/EN)

Investing in the future: projects of international financial organizations in Eurasia

The report analyzes 10 fundamental trends in non-sovereign financing by international financial institutions in the Eurasian region and formulates a number of proposals for more active and diversified IFI investments in development projects.



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