WHITE PAPER 1

Unlocking Grid Capacity Through Risk-Based Operation

A practical framework for coordinated deployment of PRA, DSA, and grid-enhancing technologies

THIS IS NOT ABOUT INCREASING RISK, BUT ABOUT MEASURING AND MANAGING RISK EXPLICITLY.

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As Energy Commissioner Dan Jørgensen put it in a recent podcast:

“We need 200 roads, we have 100 roads, but we only use 50 of them.”

In reality, the situation is even more constrained. The roads that are in use are not fully utilized, typically operating below their theoretical capacity due to unquantified security margins.

This means that the system effectively makes use of on average corresponding to ~35–43 fully loaded equivalents [DERIVED – based on IEA system utilisation discussion].

— **underscoring that unlocking existing capacity is as critical as building new infrastructure.**

Illustrative interpretation (non-analytical)

Table of Contents

Glossary of Acronyms

Acronym	Definition
CSAM	Coordinated Security Assessment Methodology (ENTSO-E)
DLR	Dynamic Line Rating
DSA	Dynamic Security Assessment (DSA) – used in this paper to denote dynamic evaluation of system stability across voltage, transient, and frequency domains.
DTR	Dynamic Transformer Rating
EC	European Commission
EENS	Expected Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
GDP	Gross Domestic Product
GET	Grid Enhancing Technologies
GW	Gigawatt
IEA	International Energy Agency
KPI	Key Performance Indicator
N-1	Single-contingency operational criterion (system operates safely with one element out)
N-k	Multi-contingency state (k elements out of service simultaneously)
NRA	National Regulatory Authority
PRA	Probabilistic Risk Assessment
TSO	Transmission System Operator
AC-OPF	Alternating Current Optimal Power Flow
DC-OPF	Direct Current Optimal Power Flow (linear approximation)
SMS	System Minutes (used as aggregated operational system risk indicator)
CENS	Cost of Energy Not Supplied
AI	Artificial Intelligence

Source attribution

Unless otherwise stated, quantitative estimates of global grid capacity potential (1,200–1,600 GW, including 750–900 GW from non-firm access and 450–700 GW from grid-enhancing technologies) are based on IEA (2026).

Percentage-based system interpretations (e.g. 15–30%) represent derived system-level interpretations presented in this paper. This estimate should be interpreted as indicative and dependent on system conditions and requires validation through operational implementation.

Throughout this paper, a distinction is made between:

- “IEA estimates” referring to quantitative values and findings directly reported in IEA (2026),
- “Authors’ interpretation” referring to system-level interpretations derived from these findings,
- and “Operational experience” referring to results observed in practical implementations.

Unless otherwise stated, percentage-based estimates (e.g. 15–30%) represent authors’ interpretations rather than directly reported IEA results.

Executive Summary — Context and Challenge

The electricity grid is now the primary constraint on the energy transition. Generation capacity continues to expand, new demand from electrification, data centres and AI is growing faster than anticipated, and a consistent finding across international assessments — including the IEA Electricity 2026 report — **is that grids, not generation, are the binding bottleneck** (IEA, 2026).

The IEA estimates that **1,200–1,600 GW of additional capacity** could be unlocked globally through operational measures applied to existing infrastructure — without building new lines. This is not a marginal adjustment. It is a structural opportunity of the same order of magnitude as the capacity shortfall driving today's connection queues and congestion costs.

That opportunity is not being realised at scale. This paper examines why and proposes a practical framework for changing that.

The core gap

Current approaches to unlocking grid capacity primarily focus on **individual technologies or local interventions**, including dynamic line rating, topology optimisation, advanced power flow control, flexibility and market mechanisms. These solutions demonstrate clear benefits in isolation, but their impact at system level remains **non-additive**, **situation-dependent**, and **difficult to quantify consistently**.

A recurring challenge — also reflected in IEA analysis — is the absence of:

- a **common baseline for system operation**,
- **consistent system-level KPIs**, and
- **quantified, operational measures of system risk**.

As a result, many promising solutions are deployed in a fragmented manner, limiting their scalability and overall impact.

A system-level interpretation

This paper proposes that the capacity identified by the IEA is not distributed across a set of independent technologies waiting to be deployed. It resides, in large part, in a shared, **implicit security and capacity margin embedded in current deterministic operational practice — conservatively defined, statically maintained, and largely invisible to the operators and regulators who must act on it.**

Making this margin accessible requires three things in combination: **the ability to quantify it continuously and in common units**; **the ability to coordinate operational measures against it across technologies and timescales**; and — critically — the ability to represent it in a form that operators in a control room can perceive and act on in real time. All three are prerequisites. None is sufficient alone.

A practical three-layer framework

To unlock this potential in a consistent and scalable way, the paper introduces a **three-layer operational framework**:

1. Decision Layer (PRA + DSA)
Provides near-real-time quantification of system risk through the integration of probabilistic risk assessment and dynamic security assessment, enabling:

- explicit baseline definition,
- dynamic security margins,
- and auditable operational decision-making.

2. Physical Layer (GET)
Improves the utilisation of network assets through:

- dynamic ratings,
- topology optimisation, and
- power flow control.

3. Security Layer (Flexibility and markets)
Manages residual risk and enables further utilisation through:

- demand response,
- storage,
- redispatch, and non-firm access.

These layers are complementary but not interchangeable and must be **deployed** in a **coordinated sequence**. Their **combined effect** is **not additive**. It is multiplicative in the sense that each layer depends on the others to deliver system-level value.

From technology stacking to system potential

A key implication of this framework is that **capacity gains should not be understood as additive contributions from individual technologies**. Instead, the achievable system-level improvement reflects the extent to which the **underlying security margin can be accessed and managed in a controlled manner**.

Based on this interpretation, **an indicative aggregate potential of 15–30%** increase in utilisable grid capacity can be derived, consistent in order of magnitude with IEA's global estimates. The 15–30% range should not be interpreted as a forecast or a generally applicable capacity uplift. It is an indicative hypothesis derived from the order of magnitude of IEA's global estimates and intended to guide system-specific validation.

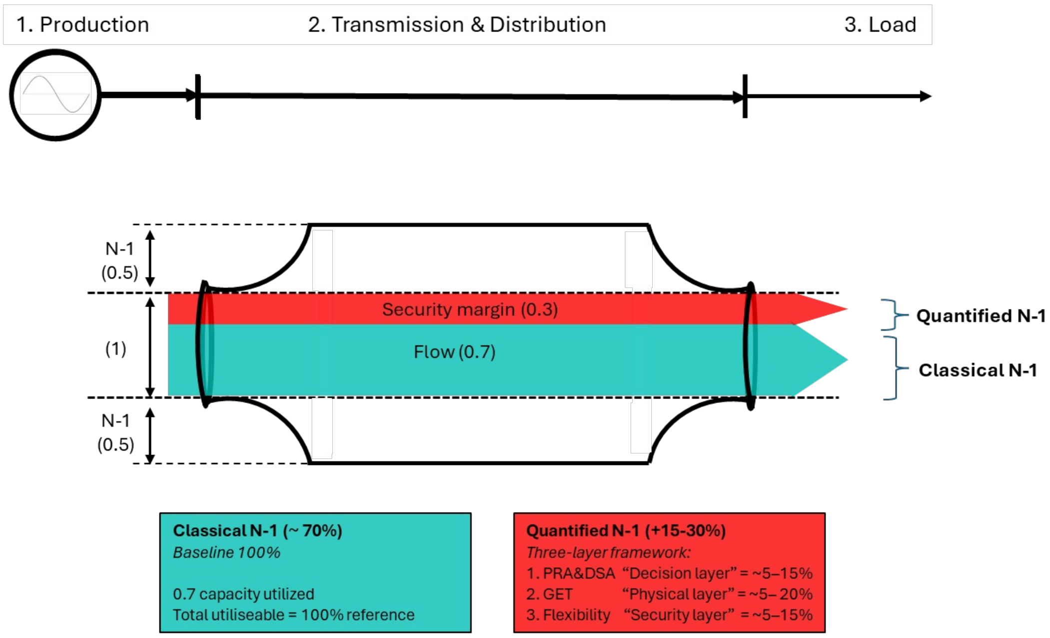


Figure 1 The “double bottleneck” capacity problem - Capacity gains do not stack linearly — unlocking value requires addressing the layers in the right order, with dynamic risk-based operation as the foundation. Conceptual illustration of overlapping contributions across system layers. Values are indicative and should not be interpreted as additive or independently realisable.

Implications for policy and implementation

In many systems, the challenge is not only a lack of physical capacity, but also a limited ability to access and manage latent capacity within existing infrastructure. Unlocking this potential requires a shift from **deterministic, rule-based operation** to **risk-informed, metric-driven system management**. Core elements of this approach have already been demonstrated in operational environments.

Key enablers include:

- development of **common risk-based KPIs** (e.g. expected energy not supplied, time-at-risk),
- integration of **near-real-time probabilistic assessment** into operations,
- and regulatory frameworks that enable **auditable, risk-based decision-making**.

While the **framework** is primarily **illustrated** at **transmission system level**, the underlying principles are **equally** applicable to **distribution systems**, where increasing levels of distributed generation and flexibility introduce similar challenges in terms of system state visibility and risk-based operation.

Conclusion

The IEA has identified a significant operational potential to increase grid capacity using existing infrastructure. This paper provides a **practical system-level interpretation of that potential**, demonstrating that:

- a significant share of this value appears to reside in **implicit, shared security margins**
- these margins can only be accessed safely through **quantified, dynamic risk management approaches,**
- and that a structured approach — combining **PRA/DSA, GET, and flexibility** — is required to unlock this potential at scale.

This represents a **shift from deploying technologies in isolation to designing grid operation as an integrated, risk-based system**, enabling faster, more efficient electrification while maintaining operational security.

Importantly, this **approach does not reduce security standards** but makes existing security margins explicit and measurable through quantified risk metrics.

1. Introduction

This paper addresses one of the most pressing structural challenges facing electricity systems today: the gap between the operational capacity that technically exists in transmission networks and the capacity that is reliably available to system users. As electrification accelerates and connection queues grow, the cost of leaving latent grid capacity unused — measured in delayed projects, curtailed renewables and slower decarbonisation — has become substantial (IEA, 2026). The challenge is not a lack of capacity, but limited ability to access and manage the capacity that already exists.

Section 3 onward of this paper diagnoses the structural reasons for this gap and proposes a **three-layer operational framework** that combines **probabilistic risk assessment, grid-enhancing technologies**, and **flexibility** within a **single decision architecture**. The argument rests on a single, testable premise: that the various operational measures highlighted by the IEA, the European Commission and ENTSO-E do not represent independent sources of capacity, but rather different mechanisms for accessing the same underlying security and capacity margin embedded in current grid operation.

Before developing that argument, **Section 2** sets out the operational and **methodological basis** from which the framework is derived. The Decision Layer described in this paper is not a theoretical proposal: it builds on more than **two decades of methodological development**, peer-reviewed publications, and operational deployment in European transmission- and distribution system operators. The paper is therefore best read not as a forward-looking concept, but as a **generalisation of an approach** that has already been **demonstrated in selected operational environments**.

The remainder of the paper is structured as follows. **Section 3 examines the core gap** between identified potential and realised system impact. **Section 4 introduces the three-layer framework**. **Section 5 explains** why technology contributions are **non-additive at system level**. **Section 6 quantifies the opportunity**. **Section 7 outlines** an **implementation pathway**. **Section 8 discusses regulatory and policy implications**, and **Section 9 sets out specific recommendations** for TSOs, regulators, ENTSO-E and the European Commission.

2. Background and Operational Basis

The **methodology** that underpins the **Decision Layer described in Section 4** originates in research conducted in the early 2000s, when a Norwegian transmission system context identified the need for reliability calculation tools capable of operating on large, meshed power grids in near real time. The **mathematical foundation combines Markov / Kolmogorov** component models with Kronecker matrix operators, an approach developed by Tørris Digernes (MathConsult) and first applied at scale in a master thesis by Arne Brufladt Svendsen (NTNU, 2002). **The technique reduces the otherwise intractable combinatorial probability state space for large-meshed power grids, into a form that can be solved within minutes on a national grid.**

From this foundation, an online reliability and risk assessment capability was **developed in cooperation** between **MathConsult, Landsnet, Goodtech Project & Services, and Statnett SF**. The capability has been tested in operational use at Statnett, the Norwegian transmission system operator 2013-2015, generating near real-time risk metrics for control-room operators and forecast for the coming hours. Near real-time risk metrics include: 1. reliability calculations of all primary and secondary equipment including weather impact, 2. combined calculations for all equipment types aggregated for all branches and 3. Reliability analysis for the system assets as a whole. This represents the **reliability analysis <u>on</u> the system as step 1**. The risk calculation combines the reliability analysis with power flow analysis producing risk metrics in near real-time, such as risk adjusted contingency list from 1-N (probability for contingency, expected energy not served (EENS) and loss of load consequence), risk graph in EENS in MWh/h and risk speedometer (system minutes (SMS) and availability). This represents the **risk analysis <u>through</u> the system as step 2**.

Furthermore, the risk and reliability capabilities provided snap-shot analysis for maintenance- and preparedness planning. In total the reliability and risk assessment capability mention has a **combined operational run-time of over 20 years** (**through several TSOs and DSOs in Norway and Iceland).** Operational implementations of probabilistic risk assessment in Nordic systems have demonstrated the ability to identify elevated system risk several hours ahead of disturbances, providing operators with actionable decision support.

The methodology has been documented in a series of **peer-reviewed publications** across the **PMAPS**, **ESREL** and **AR2TS** communities between 2004 and 2018, including treatments of online reliability assessment (PMAPS 2012), the integration of forecasted and real-time weather influence (ESREL 2015), and the publication of a model for weather-dependent online reliability assessment in the **Journal of Risk and Reliability** (2017). Earlier work addressed the benefits of probabilistic methods in primary and secondary equipment maintenance (**CIRED 2003**), analysis including reliability, income and cost (PMAPS 2004), delivery reliability analysis (ESREL 2007), and the regularity challenges of electrifying large-scale offshore installations from land (ESREL 2009). The mathematical solution discovered by Tørris Digernes and applied in Arne Brufladt Svendsen's master thesis in 2002 was later included in **Marvin Rausand** renowned textbook "**System Reliability Theory" Second Edition 2004, Chapter 8.8 Complex system**.

Operationally, the approach has been recognised through two consecutive nominations for "**Norway's Smartest Industrial Enterprise**" (2014 and 2017) and a nomination for the national **S.P.I.R. prize for climate technology and renewable energy** in 2017. The approach received the **RGI Grid Award for Good Practice of the year 2025**, at the PCI in Brussels.

Although the operational deployment described above is European, the underlying methodological challenges are global. The **IEA's identification of 1,200–1,600 GW of unlockable capacity worldwide** is itself an explicitly global figure, and parallel **concerns** about **deterministic operation, congestion management and the integration of variable renewables are being raised** by transmission operators and regulators across North America, Asia-Pacific and Latin America. What follows in this paper, from **Section 3 onward, can therefore be read as a generalisation of a demonstrated operational capability, presented in a form intended to be relevant to any electricity system facing the same structural pressures.**

Dynamic Security Assessment (DSA) has been studied and implemented in both academic and industrial contexts for several decades. Early industrial implementations developed by Siemens demonstrate the capability to evaluate system stability under large sets of contingencies in near real time, supporting operator decision-making in highly stressed system conditions (Lerch & Rühle, Siemens AG).
These systems integrate assessments of **voltage, transient and frequency stability**, enabling operators to identify and rank critical contingencies and **assess system stability margins during operation**. As power systems are increasingly operated closer to their technical limits, DSA has become a key tool to prevent cascading failures and large-scale blackouts (Heyde & Krebs, Siemens AG).

More recent work combining steady-state and dynamic security assessment shows that coordinated analysis of multiple stability domains enables **increased utilisation of existing infrastructure** while **maintaining system security**. Such approaches introduce the concept of curative operation and demonstrate that improved coordination between static and dynamic assessments can reduce redispatch and improve overall system efficiency (Raab et al.).

2.1 Positioning within existing literature

Dynamic Security Assessment (DSA) has been extensively studied as a tool for evaluating power system stability under contingency conditions. Academic and industrial work has demonstrated the capability of DSA to assess voltage stability, transient stability, and frequency behaviour in near real time, supporting secure system operation and blackout prevention (Lerch & Rühle, n.d) and (Heyde & Krebs, n.d).

Industrial implementations further show that such tools enable operators to analyse **large numbers of contingencies** and **operate systems closer to technical limits**, particularly in highly interconnected and heavily loaded transmission networks. Recent work has also explored the integration of steady-state and dynamic assessments introducing the concept of curative operation and highlighting the potential for improved utilisation of grid infrastructure (Raab, n.d).

However, existing literature and implementations primarily focus on *stability assessment as an isolated function*. They do not provide a consistent system-level framework for:

- integrating stability assessment with probabilistic risk metrics
- coordinating multiple operational measures (GET, flexibility, non-firm access)
- defining a common baseline for system operation
- enabling auditable, risk-based decision-making

At the same time, international analyses (IEA, 2026) identify substantial latent capacity in existing grids and emphasise that multiple operational measures interact in a non-additive manner. This indicates that the primary challenge is not the availability of technologies, but the absence of a unified operational framework linking system state, risk, and operational decisions.

The contribution of this paper is to bridge this gap by introducing a structured, **three-layer operational framework that integrates probabilistic risk assessment, dynamic security assessment**, and **grid-enhancing technologies** into a **coherent decision architecture.** In this context, **PRA and DSA** is positioned as a **key enabling capability** within a broader system-level approach to managing shared security margins rather than as a standalone analytical tool.

2.2 Emerging AI-based computational capabilities

Recent advances in machine learning provide important new capabilities that can significantly enhance both probabilistic risk assessment (PRA) and dynamic security assessment (DSA).

In particular, recent work by **Google DeepMind** demonstrates that **deep learning** models can approximate full AC optimal power flow (AC-OPF) solutions with **near-optimal accuracy (within ~1%)** while achieving execution times on the order of tens of milliseconds, even for large-scale systems (up to 10,000 buses). Furthermore, these models show **robustness to N-1 topological perturbations**, a key requirement for security-constrained analysis (Piloto et al., 2024).

This represents a significant shift compared to traditional approaches, where operators rely on **simplified DC approximations** or **limited scenario analysis due** to **computational constraints**. The ability to rapidly evaluate **near-AC-feasible operating points** enables a **much larger set of scenarios** to be analysed **in near real time.**

From a system perspective, this development **does not replace existing PRA or DSA methodologies**, but rather **strengthens them** by enabling:

- faster evaluation of operating states across a wide range of contingencies
- improved integration between steady-state optimisation and dynamic assessment
- more realistic representation of system constraints compared to DC approximations

In the context of the framework proposed in this paper, **such AI-based solvers** can be **understood as computational enablers within the Decision Layer**, supporting the transition from static, deterministic operating limits towards dynamic and risk-informed system operation.

While these approaches are still emerging, they provide a credible pathway for scaling both PRA and DSA methodologies to the complexity and speed required in future power system operation.

This aligns with industrial developments such as **real-time probabilistic risk analysis**, **real-time dynamic security assessment** platforms, indicating a **convergence between advanced analytics, AI-based optimisation, and operational decision support.**

3. The Core Gap — From Technology Potential to System Reality

3.1 A consistent observation across initiatives

Across recent analyses and policy initiatives — including the IEA *Electricity 2026* report and ongoing European Commission efforts — there is broad agreement on three key points (IEA, 2026):

- Significant additional grid capacity can be unlocked through operational measures.
- A range of technologies and mechanisms are already available, including Grid Enhancing Technologies (GET), non-firm access, and flexibility solutions.
- Accelerating their deployment is critical to support electrification, renewable integration, and emerging demand sources such as AI and data centres.

Despite this alignment, a consistent gap remains between **identified potential** and **realised system impact**. While individual solutions continue to demonstrate value in pilots and local applications, their contribution at **system level remains limited and difficult to scale**.

3.2 From local optimisation to system-level complexity

A key reason for this gap is that most current approaches are inherently **local in nature**, addressing:

- individual transmission corridors,
- specific constraints or bottlenecks,
- or isolated operational use cases.

Examples include:

- increasing line ratings through dynamic line rating (DLR),
- redistributing flows through topology optimisation,
- or managing congestion through redispatch and flexibility.

While such measures can be highly effective in specific contexts, their overall impact on system performance is constrained by three characteristics:

- **Non-additivity** – multiple measures often affect the same underlying constraint or margin (IEA, 2026)
- **Interdependence** – applying one measure changes the conditions under which others operate
- **Situational variability** – effectiveness depends on weather, topology, and system conditions

As a result, improvements achieved locally do not translate linearly into **system-wide capacity gains**.

3.3 The role of implicit security margins

Underlying this challenge is a more fundamental characteristic of current grid operation: **A significant share of available capacity is embedded in implicit, conservative security margins** (IEA, 2026).

In deterministic N-1 operation, system security is ensured by applying:

- worst-case assumptions,
- static operating limits,
- and predefined contingency criteria.

These approaches are robust and well-established, but they also imply that margins are **not dynamically adjusted to actual system conditions**, the distance between the current operating point and critical system states (N-k) is **not explicitly quantified** and available capacity is often constrained by **assumed rather than measured risk**.

This results in a situation where:

- the system may operate safely far below its critical limits,
- while still being unable to utilise available capacity due to static constraints.

3.4 The absence of a common operational reference frame

A further consequence is the absence of a **shared, system-level reference frame** for evaluating the impact of different measures. Today: **operators** manage system security, but largely through implicit margins, **technology providers** demonstrate improvements using local or asset-level metrics and **regulators and planners** require consistent, auditable indicators of system performance.

However, these perspectives are not consistently aligned.

There is a lack of:

- **quantified system-level risk metrics,**
- **common baselines for operation**,
- and **comparable KPIs across technologies and interventions**

Without such a reference frame, it becomes difficult to evaluate the combined impact of multiple measures, compare digital solutions to traditional grid investments or justify operational changes within regulatory frameworks.

3.5 Fragmentation as a structural outcome

In the absence of a common framework, the system naturally evolves toward **a fragmented landscape of solutions, each optimising a specific aspect of system performance.** This can lead to: parallel deployment of technologies targeting the same constraints, limited visibility of overall system impact and increased hesitation among system operators to rely on such measures in critical operation.

In practice, this fragmentation results in a form of **"patchwork digitalisation"**, where individual solutions are technically sound but collectively do not deliver the expected system-level gains.

3.6 A gap between potential and operability

The combined effect of these factors is a structural gap between **what is technically possible**, and **what is operationally and regulatorily deployable at scale.**

IEA estimates show that substantial capacity can be unlocked, but:

- the mechanisms for doing so remain **partially defined**,
- the interaction between technologies is **insufficiently structured**,
- and the operational conditions under which capacity can be safely utilised are **not consistently quantified**.

3.7 Implication: the need for a system-level operational structure

The preceding analysis points to a structural conclusion. The challenge facing electricity systems today is not a shortage of technologies capable of improving grid utilisation. A substantial range of tools already exists — probabilistic risk assessment, dynamic security assessment, dynamic line rating, topology optimisation, power flow control, flexibility, and non-firm access. Each has demonstrated value in specific contexts. The problem is that they are deployed into a system that lacks the operational structure needed to use them coherently.

What is missing is not another technology. It is a **common operational reference frame**: a **consistent way of defining system state**, **quantifying risk**, and **evaluating the impact of decisions across different measures**, **time horizons**, and **system conditions**. Without this, individual technologies continue to deliver local improvements that do not aggregate into system-level gains. **Fragmentation is not a consequence of poor implementation — it is a structural outcome of the absence of a unifying framework.**

Such a **structure** would need to **fulfil three functions**. **First**, it must provide a **common baseline** — a consistent, quantified description of the current system state against which the effect of any operational measure can be evaluated. **Second**, it must **express risk in a form that is operationally usable**: not as a binary pass/fail against a deterministic criterion, but as a continuous metric that can be monitored, compared, and acted upon in near real time. **Third**, it must enable coordination — the **ability to evaluate how different measures interact**, and to sequence or combine them in a way that produces genuine system-level improvement rather than local optimisation that cancels or displaces elsewhere.

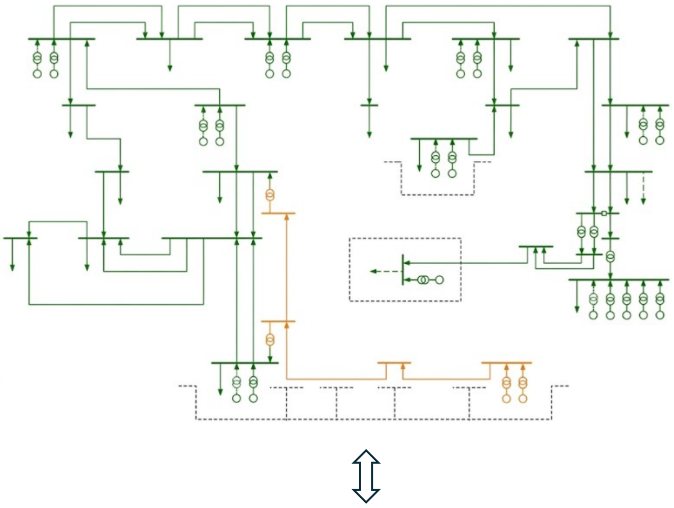
This is what motivates the framework presented in Section 4. Before developing that framework, however, it is necessary to address a prior question that the analysis in this section has surfaced but not yet resolved: if the operational structure described above is to function in a control room environment, what kind of representational capability does it require from the tools that operators actually use?

This is not a peripheral implementation detail. It is central to whether risk-based operation can be made to work in practice — and it is the subject of the following section.

3.8 System-Level Complexity and the Need for a New Operational Representation

3.8.1 The operator’s problem

Traditional representations of **power systems are based** on **graph structures**, where nodes and edges represent buses and transmission lines. While this representation is well suited for physical network modelling, it does **not fully capture the multi-dimensional dependencies** that characterize real system operation.



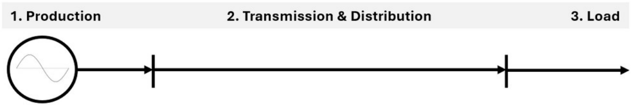


Figure 2 Conventional graph-based representation of the power system & simplified representation. Conventional graph-based representation, where nodes and edges represent buses and transmission lines, emphasizing pairwise physical connections emphasizing pairwise and independent relationships.

This structure is not imposed on the power system from outside. It reflects the actual nature of the constraints that risk-based operation must manage. The hypergraph representation makes explicit what the conventional graph conceals: that the binding constraints on system operation are often multi-element, state-dependent, and coupled in ways that cannot be decomposed into independent pairwise relationships without loss of critical information.

The transition to risk-based operation described in the preceding section places a qualitatively different demand on the operator. Under a deterministic N-1 regime, the relevant question at any moment is bounded and binary: does a single contingency cause a violation, or does it not? The representational tools available in most control rooms were designed for precisely this question — two-dimensional network diagrams showing buses, lines, and substations, typically for a sub-region of the system at a time. For deterministic operation, this is adequate. Each constraint can, in principle, be traced to a specific line, node, or contingency.

Risk-based operation changes the nature of the question fundamentally. An operator working within the Decision Layer described in this paper must assess — in near real time — how probabilistic contingency ranking, dynamic stability limits, weather-dependent asset ratings, and active flexibility resources interact to define the current risk level of the system as a whole. The constraints are no longer pairwise. A single operational decision may be influenced by combinations of system elements that have no simple geographic or topological relationship to one another. These are not independent constraints acting in parallel. They are overlapping, coupled system states that must be understood as a whole.

3.8.2 From graph to hypergraph representation

The standard representational basis for power systems is a graph: nodes represent buses, edges represent physical connections. This captures network topology accurately and supports a wide range of analytical tasks. Its limitation is structural — a conventional graph edge connects exactly two nodes and therefore represents only pairwise relationships. It cannot natively express constraints that involve three or more system elements simultaneously, or operational limits that emerge from combinations of system states rather than from individual components.

A hypergraph generalises this structure. A hyperedge can connect any number of nodes simultaneously, allowing a single representational element to capture:

- shared security constraints affecting multiple corridors or regions concurrently,
- contingency interactions where the consequence of one outage depends on the combined state of several other components,
- stability limits that are functions of loading patterns across a sub-system rather than of any single line,
- and the non-additive nature of capacity contributions from different operational measures — the same underlying system margin expressing itself through different physical mechanisms in different parts of the network.

A two-dimensional representation of a sub-network cannot convey this. The risk of misinterpretation — and consequently of either excessive conservatism or unsafe decisions — increases precisely as the system is operated closer to its limits, which is the condition under which risk-based operation is most needed. This is not a secondary concern to be addressed in a later phase of implementation. It is a prerequisite for the Decision Layer to function as intended in operational practice.

3.8.3 Independent convergence: the Norwegian power system in three dimensions

This representational approach is not derived from theoretical considerations alone. Work on abstract representation of power system networks as a function of system properties — including reliability and regularity characteristics — was developed in a Norwegian transmission system context and presented at ESREL 2014 (Svendsen et al., 2014). That work produced a three-dimensional representation of the Norwegian power system in which the position and connectivity of network elements are determined not by geographic layout, but by their system-level properties — how they behave under stress, how they contribute to or relieve system risk, and how they interact with one another as a function of system state.

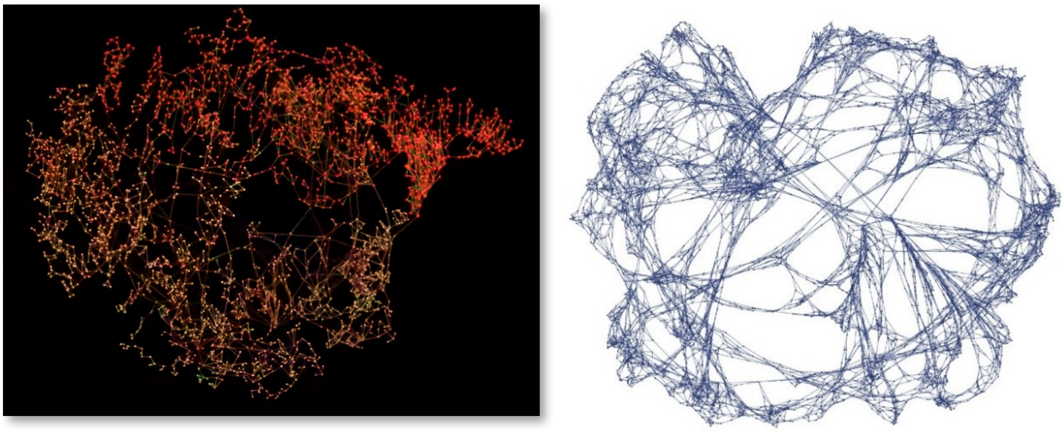


Figure 3 Left — three-dimensional representation of the Norwegian power system organised as a function of system properties (Svendsen et al., ESREL 2014). Right — example hypergraph structure (Wolfram, 2020). The two representations emerged independently from different fields. Their structural similarity reflects a shared underlying property: when the relevant interactions of a complex system are multi-dimensional and non-pairwise, conventional graph representations are inadequate, and hypergraph-like structures emerge naturally from representing the system as a function of state rather than physical topology.].

The structural similarity between the Norwegian system representation and the hypergraph structures described by Wolfram (2020) in the context of fundamental physics and complex systems modelling was not the product of a common methodology. It emerged independently, from the same mathematical necessity. When the properties of a system are non-pairwise and state-dependent, a conventional graph is an inadequate basis for representation — regardless of the domain. The convergence from two independent directions lends weight to the claim that this representational shift is not a modelling choice but a structural requirement.

3.8.4 Implication for the double bottleneck

The simplified power system illustration introduced earlier in this paper depicts what appears, in a conventional two-dimensional representation, to be two distinct capacity bottlenecks — two separate problems likely to be addressed by separate measures. Viewed through a hypergraph structure, a different interpretation becomes available. The two constraints may be understood as two manifestations of the same underlying system margin: the same shared security limit expressing itself at different locations under different loading conditions.

An operator working with a two-dimensional diagram will tend to treat them as independent problems, because the representation provides no basis for seeing their common origin. An operator working with a system-state representation — one in which the position and connectivity of elements reflect their risk properties rather than their geographic location — can recognise the coupling and act on it.

This distinction bears directly on the 15–30% capacity uplift hypothesis developed in Section 6. A material share of that potential does not reside behind a single identifiable constraint that a specific technology can release. It is distributed across overlapping margins whose common origin is only visible at the system level. Accessing it requires that operators can perceive the system state at that level of abstraction and make decisions accordingly. The representational question and the capacity question are not separable: one is a precondition for realising the other.

3.8.5 Implications for control room tools and interface development

The operational consequence is that realising the potential described in this paper will require control room tools and decision support interfaces that go beyond the current paradigm of network diagram visualisation. Geographic and topological representations remain essential for many operational tasks and are not made redundant by this framework. They must, however, be complemented by system-state representations capable of conveying the information that risk-based operation actually requires:

- the current risk level of the system as a whole, expressed as a quantified and continuously updated metric,
- the sensitivity of that risk level to specific candidate operational decisions,
- the interactions between constraints across different parts of the system, including constraints with no simple pairwise topological relationship,
- and the contribution of individual technologies and measures to the overall system margin, expressed in common risk units rather than asset-level performance indicators.

Meeting these informational requirements is as much a representational and interface challenge as it is a computational one. It is a challenge that any implementation of the three-layer framework must address explicitly — not as a future aspiration, but as a design requirement from the outset.

4. A Three-Layer Framework for Risk-Based Grid Operation

4.1 From fragmented solutions to operational architecture

The preceding analysis has established three things. First, that a substantial and quantifiable capacity potential exists within current transmission infrastructure — one that cannot be released by adding technologies incrementally within a deterministic operational regime. Second, that realising this potential requires a common operational reference frame: a consistent basis for defining system state, quantifying risk, and evaluating how different measures interact across time horizons and system conditions. Third, that this reference frame must be legible to the operators who act on it — which requires representational tools capable of conveying multi-element, state-dependent system constraints in a form that supports real-time decision-making.

These three requirements are not independent. A risk quantification methodology that cannot be expressed in operational terms remains an analytical exercise. A decision support interface that is not grounded in a coherent risk metric provides visualisation without meaning. And a set of operational measures — however individually capable — that lack a common reference frame will continue to produce local improvements that do not aggregate into system-level gains.

The central challenge, in other words, is not the availability of individual technologies. It is the **absence** of a **coherent operational structure** that allows those technologies to be applied in a coordinated and scalable manner. Current approaches tend to focus on optimising specific assets, addressing individual constraints, or deploying isolated digital and flexibility solutions. While effective in isolation, such approaches lack a system-level integration mechanism, leading to fragmentation and limited scalability. This suggests a need to move from **technology-centric deployment** to **system-level operational architecture** — building on ongoing work in probabilistic security assessment and coordinated security methodologies (IEA, 2026).

4.2 Overview of the three-layer model

To address this gap, this paper proposes a **three-layer framework** for grid operation, structured around distinct but interconnected functions:

1. **The Decision Layer** — quantifying and managing system risk in near real time, establishing the common baseline against which all operational actions are evaluated.
2. **The Physical Layer** — improving utilization of existing network assets through Grid Enhancing Technologies, evaluated and coordinated against the system-level risk baseline.
3. **The Security Layer** — managing residual risk through flexibility and market-based mechanisms, activated in response to identified system conditions.

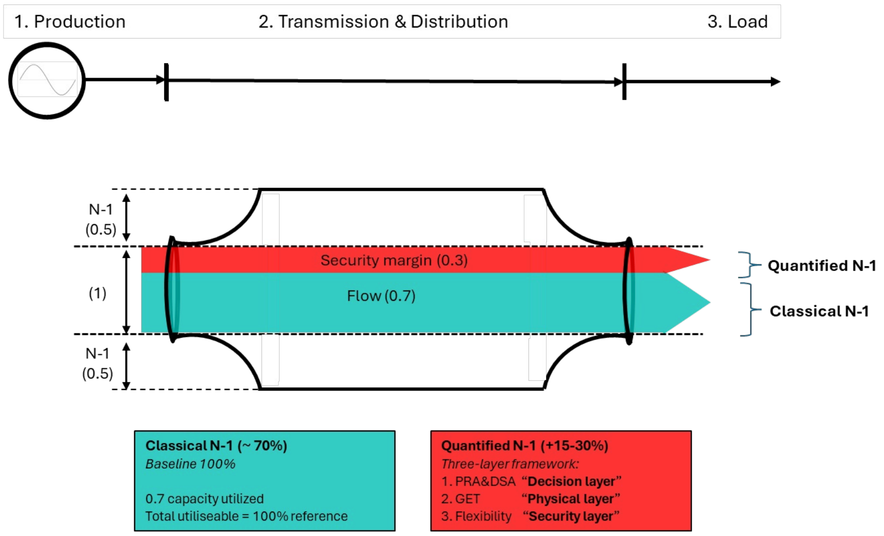


Figure 4 The "double bottleneck" capacity problem and opportunity (simplified representation)

These layers are **functionally different**, operate on **different timescales**, and require **coordinated interaction** to achieve system-level impact. They are not interchangeable, and their effectiveness depends on correct sequencing and integration.

One further requirement cut across all three layers and is a direct consequence of the analysis in Section 3.8: the outputs of the framework must be representable in operational environments in a form that operators can perceive and act on. A risk metric that exists only in the assessment system and cannot be conveyed to the operator in the control room is operationally inert. The representational question is therefore embedded in the design of each layer, not deferred to implementation.

4.3 Layer 1 – Decision Layer (PRA + DSA)

The **Decision Layer** provides the foundational capability required to operate the grid in a **risk-informed and adaptive manner**. Its primary role is to quantify system-level risk in **near real time**, establish a **common baseline for system state** and provide **decision support** for operational actions. This is achieved through the integration of **Probabilistic Risk Assessment (PRA)** and **Dynamic security assessment (DSA).** The operational interaction between PRA and DSA is further illustrated in **Appendix A.**

Industrial implementations of Dynamic Security Assessment, such as Siemens' Gridscale X DSA platform, demonstrate how dynamic stability analysis can be integrated into real-time operational environments. These solutions provide automated stability assessment, contingency ranking, and operator decision support based on large-scale simulations executed in parallel.

They enable continuous evaluation of system stability across voltage, transient, and oscillatory domains, providing operators with actionable insights into system security margins. By supporting operation closer to *stability limits while maintaining situational awareness, such tools illustrate the practical feasibility of transitioning from static security constraints to dynamic, risk-informed system operation.*

However, while these implementations provide critical capabilities, they are typically focused on stability assessment alone. The broader integration of such capabilities into a coherent, system-level decision framework — **including probabilistic risk assessment (PRA)** and coordination with physical and market-based measures — remains largely unstructured in existing operational practice.

Together, these enable:

- explicit representation of the system's **distance from critical N-k states**,
- continuous evaluation of **probability and consequence**,
- and the transformation of static security margins into **dynamic, measurable quantities**.

This layer addresses the central limitation identified in Section 3: the reliance on **implicit and assumed margins** rather than quantified risk.

By making system risk **visible**, **comparable**, and **auditable** the Decision Layer provides the necessary reference framework for both operational and regulatory decision-making.

4.4 Layer 2 – Physical Layer (Grid Enhancing Technologies)

The **Physical Layer** consists of technologies that enhance the utilisation of existing grid infrastructure. These include technologies like Dynamic Line Rating (DLR) and dynamic transformer rating (DTR), Topology Optimisation, Advanced Power Flow Control and reconductoring and uprating measures.

These technologies increase the **effective capacity** of network components, redistribute power flows and alleviate local constraints. However, their impact is inherently **local**, **condition-dependent**, and **interdependent with system state**. As such, their full value can only be realised when their effects are evaluated in a **system-level context** and coordinated based on **actual system risk**.

Without the Decision Layer, deployment of these technologies' risks:

- limited scalability,
- conflicting operational effects,
- and lack of verifiable system-level benefit.

4.5 Layer 3 – Security Layer (Flexibility and markets)

The **Security Layer** provides mechanisms to manage residual risk and enable further utilisation of the grid. This layer includes **demand response**, **energy storage**, **redispatch mechanisms** and **non-firm access arrangements**.

These mechanisms increase the system's ability to respond to disturbances, provide operational flexibility under stressed conditions and enable controlled operation closer to system limits.

Importantly, they operate as **corrective or preventive actions**, activated in response to identified system conditions.
Their effective use depends on:

- timely and accurate identification of risk,
- and clear prioritisation based on system-level impact.

This again highlights the dependency on a common decision framework.

4.6 Interaction between layers

The three layers form a **coherent operational system**, where each layer plays a distinct role:

- The **Decision Layer** defines how much capacity can be used safely.
- The **Physical Layer** determines how capacity can be increased locally.
- The **Security Layer** ensures that remaining risks can be managed.

Together, they enable a transition from a static, constraint-based operation to **dynamic, risk-informed system management**.

From an operational perspective, the three-layer framework can be interpreted as a structure where risk is quantified across layers. At system level, probabilistic methods allow the aggregation of large sets of contingencies into a single, continuously updated risk metric. This includes the interaction between reliability models, system state, and stability constraints.

While each layer addresses different physical and operational aspects of the system, their combined representation enables a unified quantification of system-level risk, supporting decision-making in complex and dynamic system conditions. See Appendix A.5 for a more detailed methodological description of risk quantification across system layer

4.7 Sequencing and dependency

A critical implication of this model is that **the layers must be deployed in the correct sequence**.

The Decision Layer provides the **precondition** for scalable deployment of the other layers by establishing the metrics and reference frame required for coordination. The Physical Layer delivers value when its impact can be measured, compared, and optimised at system level. The Security Layer extends system utilisation by managing residual risk, but depends on both:

- accurate risk quantification, and
- effective control of physical flows.

This sequencing reflects a shift from introducing technologies individually to **building a layered operational capability**.

4.8 From technologies to system capability

The proposed framework shows that the main challenge is not identifying additional technologies but structuring their interaction in a way that produces **consistent system outcomes**.

In this context the combination of PRA/DSA, GET, and flexibility does not represent a stack of additive solutions, but a **coordinated approach to accessing and managing a shared system margin**.
This perspective provides a practical bridge between:

- the **technology-focused view**, and
- the **system-level potential** identified by IEA.

5. From Additive Technologies to System-Level Potential

5.1 The limitation of additive thinking

Discussions on grid capacity improvement are often framed in terms of **individual technology contributions**, where each measure is associated with a potential percentage increase in capacity.

Examples include:

- dynamic line rating increasing capacity under favourable conditions,
- topology optimisation redistributing flows,
- or power flow control relieving specific bottlenecks.

While such estimates are useful to illustrate potential, they can lead to a **misleading interpretation** if considered additively.

In practice **capacity gains from different technologies cannot be summed linearly.** This limitation is explicitly recognised in analytical frameworks, including those underpinning recent IEA assessments, where technology effects are described as **non-additive and system-dependent** (IEA, 2026).

5.2 Overlapping constraints and shared margins

The reason for this non-additivity lies in the way grid constraints are structured. Different technologies often act on the **same transmission corridors**, relieve **the same congestion points** or access **the same underlying operating margins**.

As a result, applying one technology changes the system conditions under which others operate, multiple measures may compete for the same operational headroom and combined effects are typically less than the sum of individual contributions.

This can be interpreted as reflecting **different ways of accessing a shared underlying resource**

5.3 Interpreting technology potential in context

Indicative ranges for individual technologies — whether expressed as percentage increases in capacity or potential system coverage — should therefore be interpreted as:

- **context-dependent contributions**,
- applicable under specific system conditions,
- and subject to interaction with other measures.

For example, a dynamic increase in line rating may only be available under certain weather conditions, topology changes are effective only under network configurations and flexibility measures depend on availability and response time.

These characteristics reinforce that technology potential is inherently **situational and conditional** and does not directly translate into system-wide capacity.

5.4 From local gains to system-level effects

The transition from **local, technology-specific improvements** to **system-wide capacity gains** depends on the ability to:

- understand how different measures interact,
- evaluate their combined effect under varying system conditions,
- and ensure that overall system risk remains within acceptable limits.

Without such coordination, improvements remain locally significant but systemically underutilised.

5.5 A system-level interpretation of capacity potential

Building on this perspective, the various operational measures identified in the literature can be interpreted not as separate sources of capacity, but as **different mechanisms for accessing and managing a common system-level security and capacity margin.**

In deterministic operation, this margin remains implicit, conservatively defined and largely static. Technologies and operational measures effectively expose parts of this margin, make it conditionally accessible or shift its utilisation across the system.

This explains both the **significant total potential** identified in aggregate estimates and the **non-additive nature** of individual contributions.

5.6 Bridging GW estimates and percentage-based understanding

IEA estimates that **1,200–1,600 GW** of additional capacity could be unlocked globally through operational measures.

At the same time, indicative analyses of system behaviour suggest that the underlying operational margin corresponds to a substantial share of total utilisable grid capacity and that realistic improvements reflect how much of this margin can be safely accessed and managed.

In this context a **15–30% increase in utilisable grid capacity** can be interpreted as a realistic aggregate outcome when multiple measures are applied in a coordinated manner. The 15–30% range should not be interpreted as a forecast or a generally applicable capacity uplift. It is an indicative hypothesis derived from the order of magnitude of IEA's global estimates and intended to guide system-specific validation.

This range is consistent with the order of magnitude of IEA's GW estimates while providing a **system-level interpretation** of how these gains arise.

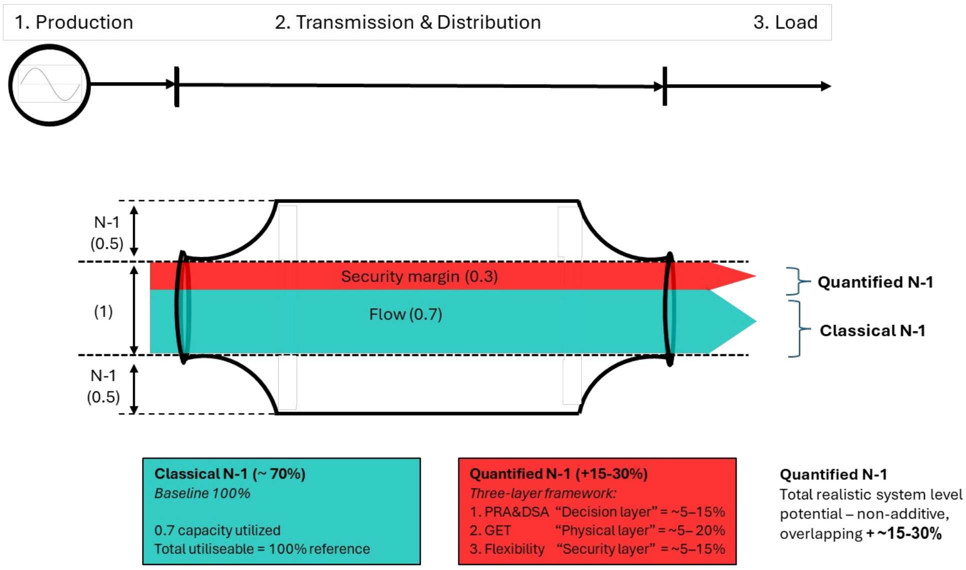


Figure 5 Addressing the technology layers in the right order. Conceptual illustration of overlapping contributions across system layers. Values are indicative and should not be interpreted as additive or independently realisable.

5.7 Implication: from stacking technologies to managing margins

The key implication is a shift in perspective from viewing technologies as independent contributors to capacity to understanding them as **tools for interacting with a shared system margin**.

In this view the achievable capacity increase depends primarily on the ability to **quantify, monitor, and control system risk** rather than on the number of technologies deployed.

This emphasises the need for a **common operational reference frame** and a coordinated approach to combining different measures.

5.8 Link to the proposed framework

The three-layer framework presented in Section 4 provides such a structure:

- The **Decision Layer** enables access to the margin by quantifying risk.
- The **Physical Layer** modifies how the margin can be utilised locally.
- The **Security Layer** extends utilisation by managing residual risk.

Together, they make it possible to translate non-additive, local technology effects into **consistent, measurable system-level capacity gains**.

6. Quantifying the Opportunity

6.1 Global estimates of unlockable capacity

Recent international analyses, including the IEA *Electricity 2026* report, indicate that a substantial amount of additional grid capacity can be unlocked through operational measures applied to existing infrastructure. These estimates indicate that:

- **Non-firm connection schemes** could unlock approximately **750–900 GW**
- **Grid Enhancing Technologies (GET)** could contribute approximately **450–700 GW**

resulting in a total potential of **~1,200–1,600 GW of additional utilisable capacity globally** (IEA, 2026).

Importantly, these figures do not reflect new infrastructure development, but rather **improved utilisation of the existing grid.** Clarification: IEA estimates primarily refer to hosting capacity for new connections, while this paper interprets the implications at system level in terms of Utilisable grid capacity.

It is worth underlining that the 1,200–1,600 GW figure quoted above is an IEA global estimate, not a European one. Although the European discussion (the IEA Electricity 2026 report, the European Grid Package (European Commission (2025)), and ongoing ENTSO-E work) is the most visible, the same underlying issue — implicit security margins and fragmented deployment of operational measures — is being identified by system operators and regulators across all major electricity systems.

Comparable initiatives in other jurisdictions illustrate the scale of the global agenda. In North America, FERC Order 1920 has tightened long-term transmission planning requirements, while FERC Order 2222 enables aggregated distributed energy resources to participate in wholesale markets. In Australia, AEMO's Integrated System Plan emphasises operational and flexibility measures alongside infrastructure build-out. In the United Kingdom, the National Energy System Operator (NESO) is restructuring planning and operations around a system-level view. Across Asia-Pacific, several large utilities are piloting dynamic line rating and topology optimisation at scale, and the Mission Innovation Power Sector Transformation programme provides a multilateral forum for sharing experience.

The framework presented in this paper is therefore intended as technology-, market- and jurisdiction-neutral. Its principal claims — that capacity gains are non-additive, that they reflect access to a shared system margin, *and that this margin can only be safely accessed through quantified, dynamic risk management — apply equally to any sufficiently complex electricity system, regardless of regulatory tradition or market design.*

6.2 Interpreting system scale

To place these figures in context, it is necessary to consider the scale of today's global power system. While exact figures vary across regions, the effectively utilisable transmission capacity can be broadly approximated (for order-of-magnitude comparison) to be in the range of:

~5,000–6,000 GW globally [DERIVED approximation]

This represents the scale of power flows that can be transported under current operational constraints. When compared to IEA's estimated unlockable capacity, this implies that:

- the identified potential corresponds to a **material fraction of the total system**,
- and is of a magnitude that can significantly influence system performance and investment needs.

6.3 Translating GW into system-level improvement

Expressing these figures in relative terms provides an additional perspective. If a system-level operational margin exists that constrains utilisation under current practices, then:

- unlocking **~1,200–1,600 GW**
- within a system of **~5,000–6,000 GW**

corresponds approximately to **~20–30% of current utilisable capacity** in order-of-magnitude terms.

This range aligns with the interpretation that a significant share of capacity is embedded within:

- conservative operational margins,
- static assumptions, and
- unquantified risk buffers.

Methodological note (order-of-magnitude interpretation): IEA (2026) estimates that 1,200–1,600 GW of additional capacity may be unlocked globally through operational measures. For contextual interpretation, total global Utilisable transmission capacity can be approximated to ~5,000–6,000 GW (order-of-magnitude estimate).

This yields a ratio of 1,200–1,600 / 5,000–6,000 ≈ **20–30%**

Considering overlapping effects, operational constraints, and non-additivity, this paper interprets a conservative achievable range of 15–30% as an indicative system-level hypothesis.

6.4 A realistic range for system-level gains

While indicative calculations suggest a theoretical range in the order of 20–30%, practical implementation considerations must be considered.

In particular:

- not all system conditions allow full utilisation of available margins,
- operational and regulatory constraints limit how rapidly changes can be implemented,
- and interactions between measures reduce total achievable gains.

Taking these factors into account, a conservative and realistic estimate derived from this system-level interpretation is that **15–30% of additional utilisable capacity can be unlocked at system level through**

coordinated operational measures. The 15–30% range should not be interpreted as a forecast or a generally applicable capacity uplift. It is an indicative hypothesis derived from the order of magnitude of IEA's global estimates and intended to guide system-specific validation. It requires validation through system-specific studies. The achievable range will vary significantly across systems depending on topology, operational practices, and available flexibility resources.

This range reflects:

- overlapping effects between technologies,
- varying system conditions,
- and the need to maintain acceptable levels of operational risk.

6.5 Distribution of potential across system layers

The total potential does not emerge from a single source, but from contributions across different aspects of system operation. Conceptually, these contributions can be understood as arising from three main categories:

- **Reduction of conservative margins** through improved visibility of system risk
- **Improved utilisation of existing assets** through physical optimisation and control
- **Enhanced system flexibility** enabling operation closer to limits under controlled conditions

Each of these corresponds to one of the layers defined in Section 4: 1. Decision Layer, 2. Physical Layer and 3. Security Layer

Their combined effect defines the total achievable gain.

6.6 Bridging analytical estimates and operational reality

A key challenge in quantifying potential lies in bridging **analytical estimates** and **operational reality.** Analytical studies often assume ideal coordination of measures, full availability of technologies and favourable system conditions.

Operational systems, however, must account for:

- uncertainty,
- incomplete information,
- and the need for robustness in real time.

This gap reinforces the importance of translating theoretical potential into **operationally achievable gains** supported by **continuous monitoring and adaptive decision-making**.

6.7 Implications for investment and planning

The magnitude of the identified opportunity has important implications for system planning:

- Unlocking 15–30% additional capacity can:
    - significantly defer or complement grid expansion,
    - reduce congestion and curtailment,
    - and accelerate connection of new demand and generation.
- At the same time, it:
    - does not replace the need for long-term infrastructure development,
    - but provides a **critical bridge in the transition period**.

This aligns with the IEA conclusion that improved utilisation of existing infrastructure is essential alongside continued investment.

6.8 Linking potential to implementation

The quantitative analysis supports a key conclusion: the potential identified by IEA is both **credible and substantial**, but its realisation depends on the ability to **translate system margin into operational practice**.

This requires:

- consistent measurement of system conditions,
- coordination across multiple types of measures,
- and operational frameworks capable of managing trade-offs between utilisation and risk.

The three-layer model introduced earlier provides a structured approach to achieving this.

Although the examples in this paper focus on transmission systems, the same system-level principles apply to distribution networks, where increasing penetration of distributed energy resources and flexibility further amplifies the need for coordinated, risk-informed operation.

7. Implementation Pathway — From Concept to Operational Practice

7.1 From potential to implementation

The preceding sections demonstrate that a substantial share of grid capacity can be unlocked through coordinated, risk-based operation. However, realising this potential requires more than the availability of technologies. It depends on the ability to:

- transition from static to **adaptive operational practices**,
- integrate multiple technologies within a **coherent framework**,
- and ensure that changes are **operationally robust and regulatorily acceptable**.

This section outlines a **practical implementation pathway** for translating the proposed framework into operational reality.

7.2 Sequencing as a critical success factor

A key insight from the proposed framework is that **the sequence of implementation matters**. Deploying technologies without a common operational reference frame, risks:

- limited system impact,
- conflicting effects,
- and reduced trust among operators and regulators.

A structured implementation pathway therefore follows a logical progression:

Step 1 – Establish the Decision Layer (PRA + DSA)

The first step is to introduce capabilities that enable **quantification and monitoring of system-level risk**.

This includes:

- implementing probabilistic assessment methodologies,
- integrating near-real-time system analysis,
- and establishing consistent **risk-based KPIs**.

Key outcomes:

- a common **baseline for system operation**,
- visibility **of risk levels across time and system conditions**,

- and a **foundation for auditable operational decisions**.

This step does not immediately increase capacity, but it **defines the conditions under which capacity can be safely utilised.**

Step 2 – Scale the Physical Layer (GET)

Once a decision framework is in place, the next step is to deploy and scale **Grid Enhancing Technologies**.

At this stage, the focus shifts to:

- increasing asset utilisation,
- relieving identified constraints,
- and optimising power flows across the network.

With a Decision Layer in place, these technologies can be:

- evaluated using **system-level metrics**,
- coordinated across locations and time,
- and prioritised based on their actual **impact on system risk**.

This enables a transition from isolated deployment to a **coordinated optimisation of the network as a whole**.

Step 3 – Integrate the Security Layer (Flexibility and markets)

The third step is to integrate **flexibility resources and market mechanisms** that allow the system to operate closer to its limits.

This includes:

- demand response and distributed flexibility,
- energy storage,
- redispatch and corrective actions,
- and non-firm access arrangements.

At this stage:

- residual risks can be actively managed,
- system utilisation can be further increased,
- and the full interaction between operational measures can be realised.

The Security Layer provides the final element required to **enable safe operation near system limits under varying conditions.**

7.3 Integration into TSO and system operator workflows

For the proposed approach to be effective, it must be **embedded in operational processes**, not treated as an external analytical function.

This implies:

- integration of risk-based assessment into real-time operations, outage planning and operational planning horizons
- alignment between control room tools, planning model and performance monitoring systems
- clear definition of decision thresholds, escalation procedures and operational responsibilities

The goal is to ensure that **risk-based decision-making becomes a routine part of system operation**.

7.4 Data and modelling requirements

Implementing the three-layer framework requires access to reliable data and appropriate modelling capabilities.

Key enablers include:

- consistent availability of:
  - asset condition data,
  - system topology and operational data,
  - weather and environmental inputs
- development of:
  - probabilistic models of failure and system response,
  - dynamic simulation capabilities,
  - and scalable computational frameworks

While data availability varies across systems, many operators already possess large parts of the required data. The main challenge lies in **integration**, **standardisation** and **operational use of data**, rather than data collection itself.

7.5 Organisational and capability considerations

Transitioning to risk-based operation is not only a technical challenge, but also an **organisational one**.

Key aspects include:

- building internal competence in probabilistic methods, system-level thinking and data-driven decision-making
- establishing collaboration between operations, planning and IT/digital teams
- ensuring alignment between technical capabilities, operational practices and regulatory expectations

This transition represents a shift from **rule-based operation** to **analytical and adaptive system management.**

7.6 Regulatory alignment and trust

A critical enabler for implementation is the alignment with regulatory frameworks. Moving toward risk-based operation requires that:

- operational decisions can be **explained, documented and audited**
- system performance is evaluated using **consistent, transparent metrics** rather than implicit assumptions
- regulatory frameworks allow for controlled use of non-firm capacity, risk-based decision-making and adaptive system operation

The availability of quantified risk metrics plays a key role in building the **trust required for such changes**.

7.7 A phased and iterative approach

Implementation is unlikely to follow a single, linear path. Instead, it is expected to proceed through **pilot projects** in selected areas, progressive expansion of capabilities, iterative refinement of models and processes.

Early applications may focus on specific corridors or regions, high-impact constraints or integration with existing operational tools.

Over time, these capabilities can be extended to:

- full system operation,

- multiple time horizons,
- and integrated decision frameworks.

7.8 From pilot to system transformation

A key objective of the proposed approach is to ensure that pilot projects lead to **scalable capabilities** rather than remaining isolated demonstrations.

This requires that pilots are designed to test **system-level integration**, validate **risk-based decision frameworks** and demonstrate **measurable impact on system performance**.

By focusing on scalability from the outset, implementation can move beyond proof of concept to **operational transformation**.

7.9 Validation and implementation pathway

The system-level hypothesis presented in this paper requires validation through system-specific studies and operational pilots.

A structured validation approach may include:

- Definition of baseline operating conditions and key performance indicators (e.g. EENS, time-at-risk, redispatch volume)
- Application of probabilistic risk assessment to quantify system risk under current operation
- Integration of dynamic security assessment to evaluate stability constraints
- Simulation of coordinated application of operational measures (GET, flexibility, non-firm access)
- Comparison of system performance under baseline and risk-informed operation
- Shadow operation in control-room environments before full operational deployment

Such an approach allows the hypothesis to be tested in a controlled and auditable manner, ensuring that increased utilisation does not compromise system security.

7.10 Summary

Implementing a risk-based, three-layer approach to grid operation requires:

- a **structured sequence** of capability development,
- integration into **operational processes**,
- alignment across **technology, organisation, and regulation**,
- and a commitment to iterative deployment and scaling.

The transition is not driven by a single technology, but by the coordinated development of **a system-level operational capability that enables safe, efficient use of existing infrastructure.** The framework does not relax security criteria; it replaces implicit margins with explicitly quantified and auditable risk.

8. Regulatory and Policy Implications — Enabling Risk-Based Grid Operation

8.1 From deterministic rules to risk-informed operation

Electricity system operation in most regions today is governed by **deterministic security criteria**, most notably the N-1 principle.

These frameworks have ensured high levels of system reliability, provided clear and robust operational rules supported by a consistent regulatory oversight.

However, as system conditions evolve, these approaches increasingly rely on **implicit and conservative assumptions**, do not reflect **real-time system conditions** and limit the ability to utilise available capacity.

This suggests a gradual transition toward a **risk-informed operational framework that complement, rather than replace, existing security criteria.**

8.2 Risk and security considerations

The framework proposed in this paper **does not reduce security standards** or **relax existing reliability criteria**. Instead, it makes implicit security margins explicit, measurable, and auditable through quantified risk metrics.

Operational decisions remain subject to defined risk thresholds, and the approach enables improved transparency in how these thresholds are applied in practice.

As such, the framework is intended to **support secure operation closer** to **system limits**, **not** to **increase the probability** of **large-scale disturbances.** Risk-informed operation should be introduced as an additional decision layer above existing deterministic security criteria, not as a relaxation of minimum reliability obligations.

8.3 The role of quantified risk in regulatory frameworks

A central requirement for such a transition is the availability of **consistent, transparent, and auditable risk metrics**.

Regulatory frameworks require that system operation can be **understood**, **verified** and **compared across alternatives**.

This creates a need for:

- **quantified system-level risk indicators**, such as Expected Energy Not Supplied (EENS), time-at-risk, probability-weighted consequence metrics
- and their integration into operational decision-making, planning processes and performance evaluation

These metrics provide a common language across operators, regulators and technology providers.

8.4 Enabling a common reference framework

As discussed in previous sections, one of the key barriers to scaling grid-enhancing solutions is the absence of a **common operational reference frame**.

From a regulatory perspective, such a reference frame must be **technology-neutral**, allow for **consistent comparison between measures** and provide an **objective basis for decision-making**.

Quantified risk offers such a framework by:

- linking operational decisions to measurable outcomes,
- enabling comparison across traditional grid investments, digital solutions and flexibility measures,
- and allowing regulators to assess whether system changes **increase or decrease overall risk**.

8.5 Supporting coordinated deployment of technologies

Current regulatory and policy structures often assess technologies individually or within specific market or asset categories.

However, the analysis in this paper indicates that system-level gains arise from **coordinated interaction** between technologies rather than from isolated deployment.

This has several implications. Evaluation frameworks should consider **combined effects**, not just individual contributions, incentives should support **system-level optimisation** and regulatory approval processes should allow for **integrated solutions** rather than only component-level improvements.

8.6 Facilitating risk-based use of non-firm capacity

A key aspect of unlocking additional grid capacity is the use of **non-firm connections**, **conditional access rights** and **flexibility-based operation**.

These approaches require that:

- the conditions under which capacity is available are **clearly defined**,
- the associated risks are **understood and acceptable**,
- and fallback mechanisms are **transparent and reliable**.

This again highlights the need for **a quantified understanding of system risk**, enabling non-firm capacity to be utilised in a controlled and auditable manner.

8.7 Building trust through transparency and auditability

For regulators, a critical concern is maintaining **transparency**, **accountability** and **system security**.

Transitioning toward more dynamic operation requires that decisions can be traced back to **quantified system conditions**, outcomes can be evaluated against **defined metrics** and processes are **auditable over time**.

Risk-based frameworks contribute to this by:

- replacing implicit assumptions with **explicit, measurable indicators**,
- enabling consistent reporting,
- and supporting regulatory oversight.

8.8 Alignment with European and international policy priorities

The transition described in this paper is closely aligned with ongoing policy objectives at both European and international level, including accelerating **electrification and decarbonisation**, reducing **connection queues and congestion**, improving **efficiency of existing infrastructure** and supporting **digitalisation of the energy system**.

In this context, risk-based operation provides a unifying element that:

- links digitalisation with operational outcomes,
- connects technology deployment with system-level impact,
- and supports more efficient use of capital-intensive infrastructure.

8.9 A possible evolution pathway for regulation

Rather than requiring immediate structural changes, the transition toward risk-based operation can be achieved through **gradual evolution** of regulatory frameworks.
Possible steps include introducing **risk-based indicators** alongside existing deterministic criteria, allowing **controlled pilot implementations** of risk-informed operation, defining **guidelines for non-firm capacity use** and establishing **common reporting frameworks** for system performance.

Such an approach allows:

- learning through implementation,
- progressive building of trust,
- and alignment between technical capabilities and regulatory acceptance.

8.10 Summary

The analysis suggests that unlocking the full potential of grid-enhancing technologies and operational measures requires a shift toward **risk-informed, metric-based decision-making**, the establishment of a **common, technology-neutral reference framework** and regulatory structures that support **coordinated, system-level optimisation**.

This does not replace existing principles such as N-1, but extends them by **making system risk explicit, measurable, and manageable in real time.**

Such an evolution would enable:

- more efficient utilisation of existing infrastructure,
- faster integration of new demand and generation,
- and a more flexible and adaptive electricity system.

Stakeholder	**Near-term action**	**Purpose**
TSOs	Implement PRA/DSA	Enable risk-informed operation
Regulators	Enable risk KPIs	Ensure auditable decision-making
ENTSO-E	Define common methodology	Ensure consistency across TSOs
European Commission	Enable regulatory framework	Support scalable implementation

Table 1 Key action suggestions

9. Conclusions and Specific Recommendations

The preceding analysis supports three structural conclusions. First, the substantial operational capacity identified by the IEA — explicitly quoted as a global figure — is real, but it is largely embedded in implicit security and capacity margins built into deterministic operation, rather than in any single technology. Second, the various technologies and mechanisms now being discussed under the heading of grid-enhancing solutions are best understood not as additive contributors, but as different mechanisms for accessing and managing those shared margins. Third, the constraint on unlocking this capacity is no longer the availability of technology: it is the absence of a common, quantified, system-level operational reference frame that allows the safe use of those margins to be measured, audited and trusted.

These conclusions translate into specific, near-term actions for the principal actors in the global electricity system. The recommendations below are framed to apply across jurisdictions, with regional bodies indicated where their mandates are particularly relevant.

For Transmission System Operators (TSOs and ISOs) worldwide
Begin or accelerate development of a **Decision Layer capability**, in the form of near-real-time probabilistic risk assessment integrated with operational data. Where such capability already exists — notably the Nordic deployment described in Section 2, but also pilots underway in North America, Asia-Pacific and Australia — expand its use beyond pilot scope into routine control-room and outage-planning decisions. Define and report a small set of system-level risk KPIs — Expected Energy Not Supplied, time-at-risk and distance-to-N-k are

reasonable starting points — using a consistent methodology that can be benchmarked across systems and shared internationally.

For National Regulatory Authorities and equivalents (NRAs, FERC, Ofgem, AER and counterparts)
Permit and incentivise controlled pilots of risk-informed operation in parallel with existing deterministic criteria. Require that proposed grid-enhancing investments be evaluated against system-level risk metrics rather than only against asset-level performance. Begin defining the conditions under which non-firm capacity, conditional access rights and dynamic ratings can be relied upon in regulatory accounting. Share methodologies and case material across jurisdictions to accelerate convergence.

For international and regional system bodies (IEA, IRENA, ENTSO-E, NERC, regional reliability councils, MEDREG, ARERA-led Mediterranean cooperation)
Develop and publish a common methodology for system-level risk metrics. In the European context, this can build on the Coordinated Security Assessment Methodology (CSAM), developed by ENTSO-E and approved by ACER under the System Operation Guideline framework. Ongoing work on probabilistic approaches to coordinated security assessment should be extended to include quantified, system-level risk metrics. In North America, this can build on NERC's reliability standards and ERO Enterprise risk reports, while globally, IEA and IRENA provide relevant cross-system benchmarks.
To enable scalability, cross-TSO comparison of risk-based KPIs should be coordinated, allowing operators, regulators and policymakers to assess performance and progress on a consistent basis.

For policymakers and multilateral fora (European Commission, US DOE, Australian DCCEEW, MOEs across Asia-Pacific, G20 Energy Transitions Working Group, Mission Innovation)
Use major policy instruments — the European Grid Package, the US Inflation Reduction Act implementation, national energy and climate plans, and equivalent national frameworks — to make explicit space for risk-informed operation alongside deterministic security criteria. Recognise improved utilisation of existing infrastructure, quantified using a common risk currency, as a complementary route to the build-out of new transmission, with measurable contributions to connection-queue reduction, congestion relief and decarbonisation targets.

For technology providers and standards bodies (IEC, IEEE, CIGRE, CENELEC)
Position individual grid-enhancing technologies within the three-layer framework rather than as stand-alone capacity sources. Report effects in terms of contribution to system-level risk metrics, not only asset-level performance. Support interoperability with TSO Decision Layer tools so that physical and security layers can be optimised against the same reference state. Contribute to international standards work that codifies risk-based KPIs in a vendor-neutral way.

Taken together, these actions describe a coordinated pathway from today's fragmented landscape of pilots and point solutions to a system-level operational capability capable of safely using a material share of the latent capacity in the existing grid — wherever in the world that grid is located. The technical and methodological foundations are established and have been demonstrated operationally. The remaining work is one of integration, standardisation, regulatory adaptation and disciplined deployment, conducted in parallel across jurisdictions rather than sequentially within them.

Importantly, this approach does not imply reduced security standards, but rather a transition from implicit to explicitly quantified and auditable system risk, enabling secure operation closer to system limits.

Note: The 15–30% range should not be interpreted as a forecast or a generally applicable capacity uplift. It is an indicative hypothesis derived from the order of magnitude of IEA's global estimates and intended to guide system-specific validation. It requires validation through system-specific studies.

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Appendix A

A.1 Conceptual integration of PRA and DSA

The framework presented in this paper is based on the complementary roles of probabilistic and dynamic analysis methods.

- **Probabilistic Risk Assessment (PRA)** quantifies system risk by evaluating the probability and consequence of a large set of possible contingencies (N-k states).
- **Dynamic Security Assessment (DSA**) evaluates system stability for selected contingencies, including voltage, transient and frequency stability.

Individually, these approaches provide valuable but incomplete perspectives:

- **PRA identifies what is likely to happen and what the expected consequences are**
- **DSA identifies whether the system remains dynamically secure under specific conditions**

When combined, they provide a more complete operational perspective:

PRA identifies which contingencies are most relevant, while DSA determines whether those contingencies are dynamically acceptable.

This allows contingency ranking to be extended from purely deterministic or purely probabilistic criteria to a combined risk–stability perspective, where **likelihood (probability), consequence (impact on load or system performance) and dynamic stability (secure / insecure response) are evaluated jointly.**

This integration supports the concept introduced in the paper:

- system capacity is constrained not only by static limits, but by a combination of probability, consequence, and dynamic system behaviour.

A.2 Operational interpretation within the Decision Layer

Within the three-layer framework (Section 4), PRA and DSA together form the core of the Decision Layer.

In an operational setting, this integration can be interpreted as follows:

1. PRA provides a continuously updated risk landscape:
    - ranking contingencies based on probability × consequence
    - identifying emerging high-risk system states ahead of time

2. DSA evaluates a subset of critical contingencies:
    - assessing dynamic stability limits
    - identifying contingencies that are unstable or close to instability thresholds

3. Combined use:
    - contingencies can be prioritized based on both risk level and stability sensitivity
    - operators can distinguish between:
        1. high-probability, low-impact events
        2. low-probability, high-impact events
        3. dynamically unstable but otherwise low-probability events

This enables a transition from deterministic “all contingencies treated equally” approaches to **risk-informed prioritisation of contingencies and operational actions.**

A.3 Illustrative operational use case

Operational experience and pilot implementations indicate from large-scale power systems indicate that the combined use of PRA and system-state analysis can provide early indication of critical system conditions.

As an illustrative example:

- A high-risk system-state may develop due to changes in generation pattern, topology, or weather conditions
- PRA can identify an increasing probability of high-impact contingencies several hours in advance
- The risk is often associated with specific system configurations (e.g. high loading on critical corridors combined with reduced local generation)

In such situations:

- PRA highlights *where and when* the system is vulnerable
- Stability- or sensitivity-based analysis (DSA or equivalent) helps determine *whether the identified contingencies could lead to cascading effects or instability*

This enables operators to:

- take preventive actions (e.g. redispatch, topology changes, reserve activation)
- reduce system risk before a disturbance occurs

In practical applications, this type of early warning capability has been shown to:

- improve situational awareness
- support more efficient use of existing infrastructure
- reduce the likelihood and consequence of large disturbances

A.4 Relation to the system-level framework

The PRA–DSA integration provides a concrete interpretation of the **Decision Layer** introduced in this paper.

- PRA → quantification of *system risk*
- DSA → validation of *system stability limits*
- Combined → **operational decision support under uncertainty**

This supports the broader conclusion of the paper:

- unlocking additional grid capacity is not primarily a question of adding technologies, but of **quantifying and managing system-level risk in a consistent manner.**

A.5 Quantification of risk across system layers

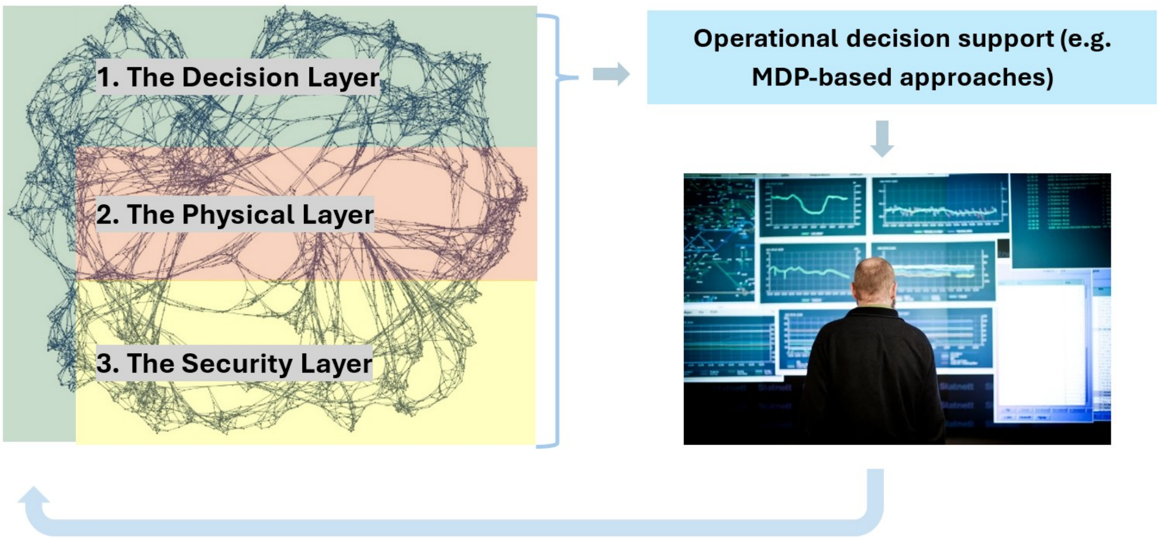

Figure 6 The power system can be interpreted as a dynamic, multi-layer structure exhibiting hypergraph-like characteristics, where each layer represents a different aspect of system state and operation.

The framework may also be interpreted from a computational and system-interaction perspective.

The combined Decision, Physical, and Security Layers can be viewed as interconnected representations of system state, where each layer captures a different aspect of system behaviour. The interaction between these layers can be understood in terms of information exchange, where quantified risk acts as a unifying metric across layers.

This layered structure can be interpreted analogously to multi-layer computational systems, where interactions between layers are governed by weighted relationships. In the context of power systems, these “weights” correspond to risk-based metrics derived from probabilistic assessment, system state, and operational constraints.

Within this representation, the overall system behaviour can be understood as a set of probabilistic pathways between system states, reflecting both physical constraints and operational decisions.

Decision-making in this context can be interpreted as a sequential optimisation problem under uncertainty. Approaches such as Markov Decision Processes (MDP) provide a structured framework for evaluating alternative actions, considering probability, consequence, and system dynamics (Milenkovic, 2026).

This interpretation does not imply the existence of a single unified computational model, but illustrates how the interaction between system layers, risk quantification, and decision-making can be understood within a consistent analytical framework supporting operational decision-making under uncertainty.

This interpretation reinforces the central argument of the paper: that unlocking grid capacity depends on the ability to quantify and manage system-level risk in an integrated and computationally tractable manner.