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# Network-Constrained Renewable Integration in Tunisia: A Deterministic Assessment of Storage Flexibility and Transmission Deliverability

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**Abstract**

High renewable-energy shares do not, by themselves, guarantee that renewable electricity can be absorbed, shifted, and delivered through a constrained network. This study uses openTEPES for a deterministic 8736 h assessment of Tunisia's 2035 power system, represented by 47 domestic nodes. It compares matched cases without and with endogenous battery energy storage system (BESS) investment and evaluates eight sensitivity families. In the no-BESS case, 265.996 GWh of modelled energy not served (ENS) and 1120.263 GWh of renewable curtailment occur in disjoint hours, indicating a temporal mismatch between scarcity and surplus. Under the central assumptions, the model selects 3.590 GW/14.361 GWh of BESS, reducing modelled ENS to zero under the represented deterministic conditions and renewable curtailment to 42.362 GWh. The sensitivity analysis shows that the model-selected BESS capacity and location, together with transmission exposure, depend strongly on demand, imposed duration, renewable-profile stress, interconnection availability, and candidate siting. Within the modelled scenario space, storage, internal transmission, and cross-border exchange therefore provide complementary forms of flexibility. The central BESS quantity is interpreted as a conditional planning benchmark, not as evidence of probabilistic adequacy or a national procurement target.

**Keywords:** battery energy storage system; renewable curtailment; energy not served; transmission deliverability; nodal power-system planning; openTEPES

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## 1. Introduction

### *1.1. Background and Previous Work*

Installed renewable capacity and annual renewable shares do not, by themselves, show whether electricity can be absorbed, shifted, and delivered when and where it is needed. As solar photovoltaic (PV) and wind generation increase, renewable surpluses, residual-load ramps, scarcity periods, and network bottlenecks may coexist within the same annual energy balance. Planning outcomes therefore depend on both renewable chronology and operating constraints [1,2], requiring modelled energy not served (ENS), curtailment, and transmission loading to be assessed jointly.

Storage, transmission, and interconnection offer complementary forms of flexibility. Storage can reduce curtailment in transmission-constrained systems [3], while generation, storage, and transmission choices evolve jointly as renewable targets increase [4]. The system value of batteries also depends on renewable penetration, system structure, cost, and duration [5–7], which motivates the coordinated consideration of grid capacity and bulk storage [8]. Under specific assumptions, batteries may complement or partly substitute for cross-border transfer [9]; however, the relative contributions of these flexibility options remain strongly system- and scenario-dependent.

High-resolution investment and dispatch models can help bridge long-term transition pathways and operational constraints. openTEPES jointly represents the operation and expansion of generation, storage, and transmission [10], while linearised network formulations enable tractable active-power routing across large chronological datasets. Such representations are nevertheless planning approximations and do not replace alternating-current (AC) load-flow analysis [11] or dedicated assessments of voltage, reactive power, and $N-1$ security.

Tunisia provides a relevant setting for electricity-system planning. Natural gas remains the principal fuel for electricity generation [12], and the national energy strategy foresees substantial solar and wind deployment through 2035 [13]. At the same time, the planned 600 MW ELMED Tunisia–Italy interconnector is intended to strengthen regional exchange alongside domestic network development [14]. Against this background, renewable availability, temporal flexibility, and domestic transmission deliverability constitute distinct but interacting planning dimensions.

Previous studies specific to Tunisia have examined alternative electricity-generation mixes [15], long-term OSeMOSYS pathways [16], interactions between energy-efficiency policies and renewable integration [17], demand and fuel-price uncertainty [18], and nationally determined contribution pathways [19]. At the regional level, TIMES-MAGe has assessed renewable deployment, mitigation pathways, and electricity trade across the Maghreb [20]. Collectively, these studies establish the strategic context for Tunisia's electricity transition. Building on this body of work, the present study adds an 8736 h nodal assessment that jointly evaluates modelled ENS, renewable curtailment, endogenous battery energy storage system (BESS) selection, and physical-circuit loading by time and location.

The broader literature also identifies complementary analyses that lie beyond the scope of the present work. Resource adequacy is inherently probabilistic [21], and the dependable contributions of solar generation and energy-limited storage are commonly assessed using capacity-credit metrics [22]. Multi-year weather variability can materially affect investment and operating outcomes [23,24], while storage size and siting depend on network conditions and the available candidate set [25]. Long-term storage economics also depend on technology-cost trajectories, degradation, replacement, and other lifetime assumptions [26,27]. Assessing the dependable contribution of interconnection, in turn, requires multi-region adequacy analysis [28]. Table 1 positions the present deterministic assessment relative to these complementary strands of the literature.

**Table 1.** Positioning of the present study within the representative literature.

| Literature Strand and References | Established Insight | Position of the Present Study |
|---|---|---|
| Chronological and network-constrained renewable integration [1–11] | Chronology, storage operation and transmission constraints affect investment, dispatch and renewable curtailment. | Provides a Tunisia-specific 8736 h nodal assessment; the linearised network representation is used for planning screening rather than AC or operational-security validation. |

**Table 1.** *Cont.*

| Literature Strand and References | Established Insight | Position of the Present Study |
|---|---|---|
| Probabilistic adequacy and storage capacity credit [21,22] | Adequacy is probabilistic; storage contribution depends on duration, dispatch and system risk periods. | Reports modelled ENS under deterministic conditions; LOLE, ELCC and outage-risk distributions are outside the scope of the analysis. |
| Multi-year weather variability [23,24] | Weather-year variability can materially affect capacity portfolios and operating outcomes. | Uses deterministic perturbations of a single reference chronology rather than a multi-year weather assessment. |
| Storage value, duration, siting and lifetime economics [5–8,25–27] | Storage quantity and location depend on network conditions, application, duration, cost and degradation assumptions. | The model-selected BESS is conditional on simplified cost assumptions, fixed technical parameters, and the represented candidate set. |
| Cross-border flexibility and capacity value [9,28] | Storage and interconnection can interact; dependable import contribution depends on multi-region conditions. | Uses stylised Algerian and ELMED availability assumptions; foreign-system adequacy, market operation and interconnector investment costs are outside the analysis. |
| Tunisia and Maghreb transition pathways [12–20] | National and regional studies establish policy, technology, mitigation and electricity-trade pathways. | Adds an 8736 h nodal assessment that jointly evaluates modelled ENS, renewable curtailment, endogenous BESS selection, and physical-circuit loading by hour and location. |
| Present study | Joint chronological and nodal screening of temporal flexibility and transmission deliverability across four central cases and eight deterministic sensitivity families. | Produces scenario-conditioned planning outputs that do not constitute probabilistic adequacy evidence, operational-security certification or definitive investment requirements. |

**Note**: AC = alternating current; BESS = battery energy storage system; ELCC = effective load-carrying capability; ENS = energy not served; LOLE = loss-of-load expectation. The comparison is selective and is intended to position the modelling scope, not to rank individual studies.

### *1.2. Motivation, Scope and Main Contributions*

This study addresses the gap between aggregate transition-pathway analysis and detailed security and adequacy studies by applying a chronological, network-constrained model to Tunisia's prospective power system. The model represents 47 domestic nodes, seven external boundary nodes, and 8736 sequential hourly time steps. Four central configurations comprise a 2024 operating baseline, a 2030 diagnostic case, and matched 2035 cases without and with endogenous BESS investment.

Eight deterministic sensitivity families test the aggregate BESS cost assumption, the assumed value of lost load (VoLL), annual demand, stylised Algerian and ELMED import availability, targeted transfer-capacity relaxations, BESS duration, candidate-node eligibility, and variable renewable energy (VRE)-profile stress. These cases are structured scenario perturbations rather than samples from a probabilistic uncertainty distribution. Accordingly, zero modelled ENS indicates balance feasibility only under the represented conditions; it does not establish probabilistic adequacy, AC system security, or a national investment requirement.

The analysis addresses three interrelated dimensions. The first examines how BESS cost, assumed VoLL, and the imposed power–energy relationship affect model-selected storage power and energy, modelled ENS, and renewable curtailment. The second assesses how stylised cross-border availability and targeted transfer-capacity relaxations affect storage selection and internal transmission exposure. The third evaluates how demand scaling, deterministic VRE-profile stress, and alternative BESS candidate domains alter the selected portfolio and its spatial consequences.

The study makes four contributions. First, it combines an 8736 h chronology with a 47-node representation to evaluate modelled ENS, renewable curtailment, BESS operation, and physical-circuit loading within a common framework. Second, it distinguishes temporal scarcity from renewable surplus, showing why annual renewable-energy availability alone is insufficient to characterise system balance. Third, it examines the interaction between temporal flexibility and spatial deliverability through matched 2035 cases and the resulting changes in internal network exposure. Fourth, the eight sensitivity families show how storage quantity, duration, siting, and transmission consequences vary across the tested economic, demand, interconnection, and renewable-profile assumptions.

Accordingly, the resulting BESS quantities, recurrent nodes, and stressed corridors are treated as scenario-conditioned planning outputs rather than probabilistic adequacy evidence or definitive investment requirements. The central-case BESS selection serves as a benchmark within the represented model, network, and candidate set, while the sensitivity analysis identifies the conditions under which that benchmark changes.

The remainder of the paper presents the modelling framework and data representation, followed by the central-case and sensitivity results, their planning interpretation, and the main limitations and priorities for future work on probabilistic adequacy, multi-year weather variability, co-optimised network-flexibility planning, and AC security.

## 2. Materials and Methods

### *2.1. Analytical Design and Inference Target*

This study applies a deterministic, chronological, and nodal optimisation framework to examine how enabling storage affects modelled energy not served (ENS), renewable curtailment, and active-power transfers in Tunisia's prospective power system. The analytical design includes a 2024 operating baseline, a 2030 diagnostic case, matched 2035 cases without and with endogenous battery energy storage system (BESS) investment, and eight deterministic sensitivity families. The central 2035 case assumes an annual demand of 33.300 TWh.

The nodal representation provides operational detail beyond national aggregates. Its 47 domestic nodes allow ENS, renewable curtailment, storage siting, and circuit exposure to be resolved by location and hour. In the central BESS case, the model produces 164 physical-circuit line-hours at or above 90% of effective capacity and 125 at or above 95%. Across the S7 candidate-domain screens, line-hours at or above 95% range from 6 to 1916. These siting-dependent differences would be obscured in a single-node model or national energy balance.

The matched 2035 cases form the main controlled comparison within the model. They share the same hourly nodal demand matrix, renewable capacities and reference profiles, thermal-unit data and static availability parameters, nodal allocations, 101-circuit network, cross-border limits, operating costs, direct-emission factors, $CO_2$ price, and ENS penalty. They differ only in the activation of continuous BESS investment and operating variables, the associated storage constraints, and the annualised BESS-investment term in the objective. Differences between the two cases therefore isolate the consequences of enabling BESS within the represented option set. This attribution does not extend beyond that option set to all feasible generation, demand-side, network, or interconnection alternatives.

Figure 1 summarises the analytical chain. The framework screens energy-balance and transmission-deliverability outcomes under the stated assumptions. Its inference scope is limited to deterministic active-power planning and excludes probabilistic resource adequacy, AC or $N-1$ security assessment, and investment-grade national expansion planning.

### *2.2. openTEPES Configuration and Formulation*

The cases were formulated as a continuous linear programme and solved with openTEPES version 4.18.16 [10] and Gurobi Optimizer 13.0.2. Binary generation investment, retirement, and commitment; binary line investment and switching; ramping; and minimum up/down-time options were disabled, while active-power network losses were enabled. Each configuration contains one period, one unit-probability scenario, one stage, and 8736 sequential one-hour load levels. The represented horizon therefore covers 52 complete weeks (364 days), rather than an 8760 h civil year. All cases use the same chronology and hour weights; annual totals refer to the represented 8736 h.

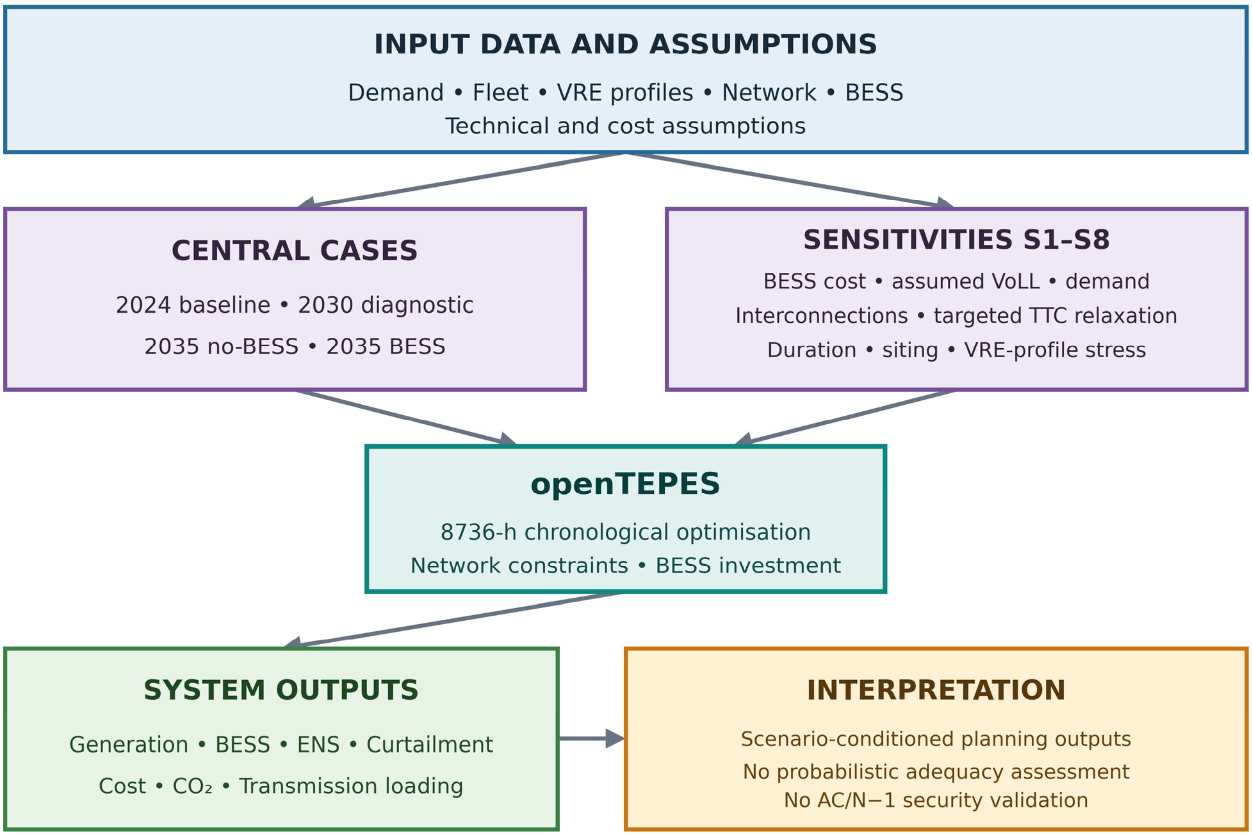


**Figure 1.** Modelling workflow and scenario structure. Central cases and sensitivity families S1–S8 are evaluated using the chronological, network-constrained openTEPES framework.

The model minimises annual system cost, as expressed in Equation (1):

$$\min C = C_{\mathrm{op}} + C_{\mathrm{CO_2}} + C_{\mathrm{ENS}} + C_{\mathrm{BESS}} \tag{1}$$

where $C$ is total modelled annual cost; $C_{\mathrm{op}}$ includes fuel and variable operating costs; $C_{\mathrm{CO_2}}$ is the cost of direct domestic operational emissions; $C_{\mathrm{ENS}}$ is the penalty assigned to unserved energy; and $C_{\mathrm{BESS}}$ is the annualised storage-investment term included only in BESS-enabled cases. A direct $CO_2$ price of 25 EUR $\mathrm{tCO_2}^{-1}$ is used. The central assumed value of lost load (VoLL) is 10,000 EUR $\mathrm{MWh}^{-1}$. It is an exogenous scarcity penalty assumption, implemented through the openTEPES input as *ENSCost*; it is not presented as an empirically estimated, consumer-specific Tunisian VoLL. The assumed VoLL range is tested explicitly in S2, consistent with the methodological distinction in [29].

For each domestic node $n$ and hour $t$, the active-power balance is given by Equation (2):

$$p^{\mathrm{gen}}_{n,t} + p^{\mathrm{dis}}_{n,t} + p^{\mathrm{imp}}_{n,t} + f^{\mathrm{net}}_{n,t} + \mathrm{ENS}_{n,t} = d_{n,t} + p^{\mathrm{ch}}_{n,t} + \ell^{\mathrm{loss}}_{n,t} \tag{2}$$

where $p^{\mathrm{gen}}_{n,t}$ denotes local generation; $p^{\mathrm{dis}}_{n,t}$ denotes BESS discharge; $p^{\mathrm{imp}}_{n,t}$ denotes imports when enabled; $f^{\mathrm{net}}_{n,t}$ denotes net transmission inflow; $\mathrm{ENS}_{n,t}$ denotes unserved power; $d_{n,t}$ denotes nodal demand; $p^{\mathrm{ch}}_{n,t}$ denotes BESS charging; and $\ell^{\mathrm{loss}}_{n,t}$ denotes allocated active-power losses. All power terms are expressed in MW. ENS is a non-negative slack penalised in the objective. Imported power is fixed to zero when the relevant cross-border transfer limit is unavailable and is otherwise bounded by the case-specific limit.

### 2.3. Data Sources, Representation and Preprocessing

Project-specific processed datasets provide the numerical model inputs, including sets and mappings, hourly demand and renewable availability, generator and network characteristics, operating assumptions, emissions, variable costs, and model options. Table A3 summarises the numerical representation, source or modelling basis, and model treatment of each data component.

The 2024 annual energy balance, Algerian imports, and reference electricity-demand data were derived from the Société Tunisienne de l'Électricité et du Gaz (STEG) Annual Report 2024 [30]. These data informed the identification and representation of Tunisia's principal demand locations. Prospective annual demand, renewable deployment, and horizon-specific infrastructure assumptions were aligned with Tunisia's 2035 energy-strategy framework [13], while the stylised 600 MW ELMED option follows the documented project rating [14]. The resulting hourly, nodal, generation, and network inputs were processed for the openTEPES implementation, as detailed below and in Table A3.

The 2035 model contains 54 nodes, 87 generating units, 101 network circuits, and 8736 hourly time steps. Of the 54 nodes, 47 are domestic and seven are external boundary nodes: four Algerian, two Libyan, and one Italian. The generator inventory comprises 37 gas-fired units, seven hydropower units, 28 solar units, and 15 wind units. The network contains 100 AC circuits and one direct-current (DC) circuit.

The inputs were prepared consistently across cases. Annual demand matrices were scaled to the stated TWh totals. The matched 2035 cases share the same demand matrix and all non-BESS exogenous inputs, while node, generator, and circuit mappings and scenario, period, stage, and duration weights remain fixed. Energy balances, costs, emissions, and network indicators are calculated using common post-processing definitions.

### 2.4. Demand Chronology and Nodal Allocation

The authors developed the domestic nodal representation using an expert-informed spatial aggregation. The 47 demand nodes provide national coverage of Tunisia's principal regions and demand centres. Node selection and demand allocation were informed by node-level demand information reported by the STEG [30]. These values were mapped to the selected model nodes and processed into the openTEPES *oT_Data_Demand* input. The resulting dataset is therefore a STEG-informed, author-developed nodal-demand representation rather than a directly published 47-node openTEPES dataset.

The reference demand chronology was constructed from electricity-demand information in the STEG Annual Report 2024 [30] and harmonised with the model's 8736 h, 52-week horizon. The resulting 2024-derived hourly nodal matrix was scaled to annual demand totals of 29.500666 TWh for 2030 and 33.300 TWh for 2035, while preserving the reference temporal profile and nodal demand shares. The 2030 and 2035 profiles are therefore scenario projections based on a common 2024 reference chronology rather than independently forecast hourly profiles. Timestamp offsets in the processed input preserve only the ordering of the 8736 hourly steps and carry no time-zone-dependent operational interpretation.

In the 2035 reference matrix, mean hourly demand is 3.812 GW, peak demand is 7.453 GW, and the load factor is 51.1%. The matrix sums to 33.300 TWh and contains no missing or negative demand values. Figure 2 shows the aggregate hourly chronology and the corresponding load-duration curve.

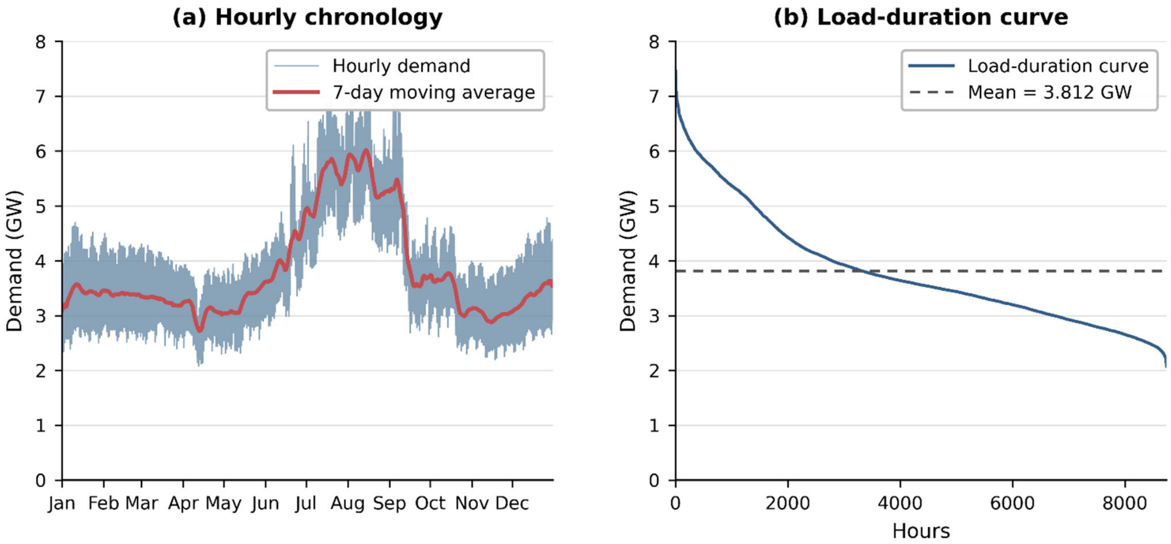


**Figure 2.** Aggregate 2035 demand profile. (**a**) Hourly chronology and 7-day moving average; (**b**) load-duration curve. Annual demand is 33.300 TWh, with mean and peak loads of 3.812 and 7.453 GW, respectively.

### *2.5. Renewable and Thermal Generation Representation*

Solar PV and wind capacities are specified exogenously by horizon, generator, and node. The 2035 case includes 43 generator-level VRE availability series: 28 solar and 15 wind. The openTEPES input *VariableMaxGeneration* specifies hourly available-power ceilings in MW rather than dimensionless capacity factors. Renewable dispatch is bounded by these hourly ceilings, and curtailment is calculated using Equation (3):

$$\mathrm{Curt}_{r,t} = A_{r,t} - p_{r,t} \tag{3}$$

where $\mathrm{Curt}_{r,t}$ is curtailed renewable power; $A_{r,t}$ is the available-power ceiling; and $p_{r,t}$ is dispatched renewable power for renewable unit $r$ at hour $t$, with all power quantities expressed in MW. Installed capacities and nodal allocations remain fixed in S8; only the prescribed hourly solar and/or wind availability ceilings are modified. Private-sector and independent-power-producer renewable units are consolidated within the solar and wind technology categories. BESS discharge is reported separately and excluded from domestic primary renewable generation because it represents previously generated electricity shifted in time. Imports are likewise excluded from the numerator used to calculate domestic primary renewable generation.

The reference VRE series represent a single chronology rather than a multi-year weather dataset. S8 applies nine deterministic annual scaling transformations and one synthetic 168 h low-VRE stress to this chronology. The low-VRE stress applies PV × 0.70 and wind × 0.50 during model hours 4674–4841, with all other hours unchanged. These cases quantify the model response to prescribed VRE-profile perturbations rather than weather-event probabilities, return periods, or probabilistic renewable uncertainty. Table A2 reports the transformations and bounding rules.

In the implemented formulation, positive *VariableMaxGeneration* values define absolute hourly availability ceilings and supersede the corresponding static *MaximumPower* values. In the reference dataset, 1215 generator-hours have hourly availability values above the corresponding static metadata while remaining within the applicable hourly ceilings. For 48 hourly entries associated with wind001 and wind002 on 1 March, VariableMaxGeneration values are missing, so the applicable static limits of 54 and 186 MW, respectively, are used. During these hours, the full 240 MW is curtailed. This fallback accounts for

5.760 GWh, or 0.51%, of no-BESS curtailment and does not affect ENS, dispatch, fuel use, emissions, or cost. Accordingly, the reference series are treated as model input profiles rather than as meteorologically validated multi-year data.

Thermal-generator inputs include node, technology, minimum and maximum output, fuel and variable operating costs, static availability, and direct $CO_2$-emission rates. Continuous output bounds and nodal balances are active, whereas binary unit commitment, start-up/shutdown trajectories, ramp constraints, and minimum up/down-time constraints are disabled, even when corresponding descriptive input fields are present. The formulation therefore represents chronological economic dispatch with relaxed unit commitment rather than detailed unit-level operation.

Operating-reserve requirements are set to zero in all hours, and reserve activation is disabled. The model includes neither sampled forced-outage states nor chronological maintenance schedules; static availability parameters therefore represent deterministic assumptions rather than a probabilistic outage model. Voltage, reactive power, inertia, frequency response, dynamic stability, and full $N - 1$ security lie outside the formulation. Accordingly, modelled ENS represents residual active-energy imbalance under the stated conditions rather than reserve-constrained reliability or operational-security compliance.

### *2.6. Nodal Network and Cross-Border Representation*

The modelled network comprises 47 Tunisian nodes and seven external boundary nodes representing the cross-border topology. Transmission expansion is treated exogenously rather than optimised within the model. Horizon-specific topologies comprise 87 circuits in 2024, 96 in 2030, and 101 in 2035. The topology is fixed within each same-horizon comparison; in particular, the matched 2035 cases use the same 101-circuit network.

The asymmetry between endogenous BESS investment and exogenous transmission is intentional. The matched 2035 comparison isolates the storage response within a predetermined network. Endogenous co-expansion would introduce route, technology, and cost trade-offs beyond the represented option set and would alter the comparison being isolated. S5 therefore uses prescribed transfer-capacity relaxations as counterfactual screening cases. Joint storage–transmission expansion could reduce, increase, or relocate the selected BESS portfolio; the central storage quantity is therefore conditional on the represented network-development assumptions.

Each circuit is characterised by its terminals, circuit identifier, type, voltage, reactance, loss factor, nominal total transfer capacity (TTC), and security factor. Active-power routing follows a linearised DC power-flow formulation [11]. Effective capacity is defined as TTC multiplied by the circuit security factor, and utilisation is measured relative to this value. Losses are enabled and allocated to nodal balances, while binary line switching and endogenous line investment are disabled. The formulation therefore supports active-power congestion screening, but not voltage, reactive-power, short-circuit, protection, stability, or $N - 1$ assessment.

The prospective 2030 and 2035 reference cases are represented as domestic zero-import stress tests. Algerian and Libyan links remain in the topology with negligible effective transfer limits, while ELMED has zero transfer capacity. The 2024 operating baseline includes 2.663 TWh of calibrated Algerian imports. S4 tests stylised Algerian and ELMED import availability through controlled 0/300/600 MW configurations. These cases exclude interconnector investment costs, foreign-system adequacy, market and outage availability, and emissions associated with imported electricity. They therefore quantify the effect of stylised import availability on the domestic model solution rather than dependable import capacity or project feasibility.

S5 applies prescribed multipliers to the direct TTC of recurrently stressed circuits, while all non-targeted network parameters remain unchanged. Because project costs, routing alternatives, construction constraints, and AC/N − 1 validation lie outside these cases, S5 is interpreted as a transfer-capacity screening exercise rather than a transmission-investment assessment.

The reference TTC values are 357 MW for Jerba–Zarzis and 179 MW for both Menzel-Temime–Nabeul and Nabeul–Hammamet. The ×1.20 and ×1.50 screens increase these values to 428.4 and 535.5 MW for Jerba–Zarzis and to 214.8 and 268.5 MW for each 179 MW circuit, respectively. The Top2 ×2.00 screen sets TTC to 714 MW for Jerba–Zarzis and 358 MW for Menzel-Temime–Nabeul; Nabeul–Hammamet is included only in the Top3 ×1.20 and ×1.50 screens. The security factor remains fixed at 0.70. Because *TTCBck* is left blank, openTEPES applies the resulting effective transfer limit symmetrically in both directions. Reactance, loss factor, topology, and all non-targeted network inputs remain unchanged.

### *2.7. BESS Candidates and Economic Representation*

BESS investment is enabled only in BESS-enabled configurations. The central candidate set consists of 27 lithium-ion (Li-ion) options: one solar-oriented candidate at each of the 17 domestic nodes hosting solar generation and one wind-oriented candidate at each of the 10 domestic nodes hosting wind generation. Six nodes belong to both groups, yielding 21 unique candidate nodes. Each candidate has a continuous investment bound of 1000 MW and a four-hour power–energy relationship, giving an aggregate pre-optimisation domain of 27 GW and 108 GWh. Candidate eligibility is determined by the generator and candidate mappings. The central selection of 3.590 GW/14.361 GWh is an endogenous model output rather than an imposed national target.

The assumed round-trip efficiency is 0.90. In the openTEPES storage balance, the charging term is multiplied by the square root of this coefficient and the discharging term is divided by the same quantity [10]. The *eChargeDischarge* constraint further couples charging and discharging by limiting their combined normalised utilisation. No binary operating-mode variable is used. The resulting hourly schedules were checked for simultaneous positive charging and discharging; no such occurrence was found in the analysed BESS cases.

Selected storage energy and power are linked by Equation (4):

$$E_{\mathrm{BESS}} = h_{\mathrm{BESS}} P_{\mathrm{BESS}} \tag{4}$$

where $E_{\mathrm{BESS}}$ is selected energy capacity (MWh), $P_{\mathrm{BESS}}$ is selected power (MW), and $h_{\mathrm{BESS}}$ is the imposed duration (h). S6 tests 2, 4, 6, 8 and 10 h.

The central investment assumption is an aggregated power-based capital expenditure (CAPEX) of 200 kEUR MW$^{-1}$ with a fixed charge rate (FCR) of 0.08 yr$^{-1}$. The corresponding annualised BESS-investment term is given by Equation (5):

$$C_{\mathrm{BESS}} = \mathrm{FCR}\, c_P P_{\mathrm{BESS}} \tag{5}$$

where $c_P$ is the assumed power-based CAPEX. The resulting annualised coefficient is 16 kEUR MW$^{-1}$ yr$^{-1}$. Because the model includes no separate energy-cost coefficient, the corresponding four-hour equivalent is 50 EUR kWh$^{-1}$. This simplified cost representation serves as a sensitivity proxy rather than a complete lifetime-cost, profitability, or procurement model. The economic assumptions are summarised in Table A3.

### *2.8. Central Cases and Deterministic Sensitivity Programme*

Table 2 defines the four central configurations. Cross-horizon differences reflect exogenous horizon assumptions, whereas the matched 2035 comparison isolates BESS activation within a common 2035 dataset.

**Table 2.** Central-case definitions and matched assumptions.

| Case | Role | Demand (TWh) | BESS Treatment | Network and Cross-Border Treatment |
|---|---|---|---|---|
| *TN2024_REF* | 2024 operating baseline | 18.613940 | Disabled | 87 circuits; calibrated Algerian imports: 2.663 TWh |
| *TN2030_REF* | 2030 diagnostic case | 29.500666 | Disabled | 96 circuits; prospective imports disabled; ELMED TTC = 0 |
| *TN2035_noB_REF* | 2035 no-BESS reference | 33.300 | Disabled | 101 circuits; prospective imports disabled; ELMED TTC = 0 |
| *TN2035_B_REF* | 2035 BESS reference | 33.300 | Endogenous continuous BESS investment | Same network and cross-border settings as *TN2035_noB_REF* |

**Note:** The paired 2035 cases share all non-BESS exogenous inputs and common assumptions. They differ only in the activation of BESS investment and operating variables, the associated storage constraints, and the annualised BESS-investment term in the objective.

Table 3 summarises the eight deterministic sensitivity families. Unless otherwise stated, each family varies a single input or admissible domain relative to *TN2035_B_REF*, while all other assumptions remain fixed. Central-value replications provide numerical consistency checks and are excluded from slope estimates, threshold estimates, and cross-family extrema. The resulting ranges characterise scenario responses and stress boundaries rather than probability-weighted uncertainty or interaction effects. Table A1 reports the exact S7 candidate-node domains.

**Table 3.** Deterministic sensitivity design and interpretation boundaries.

| Family | Tested Lever and Configurations | Comparator/Control | Interpretation Boundary |
|---|---|---|---|
| **S1** | **Aggregated BESS cost:** 150, 200, 300, 400, 600, 800 and 1000 kEUR MW$^{-1}$ | *TN2035_B_REF*; 200 kEUR MW$^{-1}$ replication | Simplified power-based cost proxy; fixed four-hour central duration |
| **S2** | **Assumed VoLL:** 2000–50,000 EUR MWh$^{-1}$ | *TN2035_B_REF*; 10,000 EUR MWh$^{-1}$ replication | Exogenous scarcity penalty; native objective values are not directly comparable as welfare measures across different VoLL assumptions |
| **S3** | **Annual demand:** 30.0, 32.1, 33.3, 36.63 and 38.3 TWh | *TN2035_B_REF*; 33.3 TWh replication | Uniform scaling of the reference load shape; no compound demand–weather–outage event |
| **S4** | **Algeria/ELMED availability:** Algeria 0/300/600 MW; ELMED 0/600 MW; combined cases; matched BESS/no-BESS cases | Matched zero-import cases | Stylised import availability; excludes foreign-system adequacy, market operation, imported emissions and interconnector CAPEX |
| **S5** | **Targeted TTC relaxation:** three corridor sets; ×1.20, ×1.50 and selected ×2.00 tests | *TN2035_B_REF* network | Direct transfer-capacity relaxation; no project cost, endogenous line investment or AC/N − 1 validation |
| **S6** | **BESS duration:** 2, 4, 6, 8 and 10 h | Four-hour central case | MW and MWh are coupled through the imposed duration; no independent energy-cost term; comparable ≥95% line-hour counts unavailable |
| **S7** | **Candidate-node domain:** unrestricted control and seven restricted siting domains | *TN2035_B_REF* and *Site_All* | Candidate domains differ in eligible nodes and headroom; recurrence is descriptive and does not imply a universal site ranking |
| **S8** | **VRE-profile stress:** nine annual PV/wind scaling cases and one synthetic 168 h low-VRE stress | Reference VRE-profile set | Prescribed transformations of a single chronology; not a multi-year weather or probabilistic assessment |

**Note:** Unless otherwise stated, each sensitivity family modifies one defined input or admissible domain relative to *TN2035_B_REF* while holding the remaining assumptions fixed. Central-value replications serve as numerical controls and are excluded from cross-family extrema and threshold interpretations. Reported responses include model-selected BESS power and energy, modelled ENS, renewable curtailment, cost and circuit loading, as applicable. The resulting ranges describe deterministic scenario responses and stress boundaries rather than probability-weighted uncertainty.

*2.9. Indicators, Post-Processing and Reproducibility*

A common post-processing framework is applied to all cases. Annual indicators include demand and served demand, generation by technology, renewable availability and curtailment, ENS, thermal generation, imports, selected BESS power and energy, charging and discharging, equivalent full cycles, direct domestic operational $CO_2$ emissions, active-power losses, cost components, and circuit-loading duration. Imports and BESS discharge are retained as separate energy-flow categories.

Equivalent full cycles, $N_{\text{cycles}}$, are calculated using Equation (6):

$$N_{\text{cycles}} = \frac{E_{\text{BESS}}^{\text{dis}}}{E_{\text{BESS}}} \tag{6}$$

where $E_{\text{BESS}}^{\text{dis}}$ is the annual discharged energy, and $E_{\text{BESS}}$ is the selected energy capacity. Annual ENS is calculated using Equation (7):

$$E_{\text{ENS}} = \sum_n \sum_t \text{ENS}_{n,t}\,\Delta t \tag{7}$$

with $\Delta t$ = 1 h. For manuscript display, annual ENS below 0.001 GWh is rounded to zero; hourly events are considered material above 0.001 MW. These are reporting thresholds, not reliability standards.

Circuit utilisation is defined by Equation (8):

$$u_{\ell,t} = \frac{|f_{\ell,t}|}{\text{TTC}_\ell\,\text{SF}_\ell} \tag{8}$$

where $f_{\ell,t}$ is circuit flow, $\text{TTC}_\ell$ is nominal transfer capacity, and $\text{SF}_\ell$ is the security factor. Loading is reported as physical-circuit line-hours at or above 90%, 95% and, where available, 99% of effective capacity. Line-hours sum qualifying hours over circuits and are distinct from system-hours. S6 retains only $\geq$99% counts and is therefore excluded from comparisons using the common $\geq$95% metric.

To distinguish avoided ENS penalties from storage profitability, the cost excluding the ENS term is also reported using Equation (9):

$$C_{\text{exclENS}} = C_{\text{total}} - \text{VoLL}\,E_{\text{ENS}} \tag{9}$$

where $C_{\text{total}}$ is the native modelled total cost, VoLL is the assumed value of lost load, and $E_{\text{ENS}}$ is annual ENS. The conversion from EUR to million euros (MEUR) is applied consistently. Emissions cover direct domestic operation only; imported-electricity emissions are outside the boundary.

All analysed cases returned an optimal solution status. Before presolve, the 2035 no-BESS configuration contains approximately 4.31 million constraints, 4.53 million variables, and 16.27 million non-zero coefficients, with zero reported primal and dual infeasibility. Common consistency checks cover annual energy balances, units, demand totals, technology aggregation, costs, emissions, and circuit identifiers. BESS-enabled cases are additionally checked for consistency among selected power, selected energy, and imposed duration, and for simultaneous charging and discharging.

Hourly ENS and renewable curtailment in the 2035 no-BESS case were also compared to determine whether their annual coexistence reflects simultaneous events or distinct operating regimes. Co-occurrence is evaluated using the 0.001 MW reporting threshold defined above, together with demand, VRE availability, thermal dispatch, and circuit loading during the identified hours.

### 2.10. Scope of Inference

The following boundaries govern the interpretation of the Results and Discussion.

**Deterministic energy balance:** Zero modelled ENS indicates that all represented nodal active-power balances are satisfied for the selected chronology, static availability parameters, network, and option set. It does not estimate loss-of-load probability, expected outage frequency, reserve sufficiency, or dependable capacity contribution.

**Renewable and demand uncertainty:** S3 and S8 apply deterministic perturbations to a single demand shape and a single renewable chronology. They do not sample correlated weather years, temperature-sensitive demand, forced outages, chronological maintenance, reserve deployment, or compound events. A probabilistic multi-year study incorporating unit and network contingencies could alter ENS as well as the selected storage quantity, duration, location, and competing flexibility mix. The present analysis therefore characterises responses across the tested scenarios rather than robustness to a probability distribution.

**Storage quantity and economics:** BESS is the principal endogenous expansion option in the central comparison; new generation, demand response, network expansion, and interconnector investment are not co-optimised as competing options. The selected 3.590 GW/14.361 GWh therefore represents a conditional central-case screening benchmark rather than a national requirement or investment recommendation. A statistical confidence interval is not meaningful for a deterministic single-chronology optimisation. Scenario dependence is instead characterised by the bounded responses across S1–S8 and the matched-case structure; the selected capacity should not be extrapolated beyond the tested option set.

**Network and interconnection:** Circuit loading and TTC relaxations are active-power screening measures. Corridors identified through these screens require subsequent AC load-flow, contingency, protection, stability, constructability, and economic assessment. Import cases assume stylised capacity availability and therefore do not establish foreign-system adequacy, market access, or dependable import contribution.

**Transferability:** The analytical framework and reporting logic may be transferable to other emerging power systems, whereas the numerical capacities, nodes, corridors, and thresholds are specific to the represented Tunisian dataset and scenario set.

## 3. Results

All results are derived from deterministic 8736 h simulations under the represented chronology, static availability parameters, network configuration, and option set. Zero modelled energy not served (ENS) indicates that nodal active-power balances are satisfied under these conditions; it does not establish probabilistic adequacy, reserve sufficiency, AC feasibility, or $N-1$ security. Transmission exposure is reported as physical-circuit line-hours at or above specified fractions of effective transfer capacity.

### 3.1. Central-Case Trajectory and No-BESS Mechanism

The 2024 operating baseline serves all 18.614 TWh of demand without modelled ENS or renewable curtailment. Total supply is 19.268 TWh, including 2.663 TWh of Algerian imports. Domestic solar PV, wind, and hydropower generate 0.976 TWh, equivalent to 5.87% of domestic primary generation, while direct domestic operational emissions reach 6.030 $MtCO_2$. The network records 195 and 39 internal physical-circuit line-hours at or above 90% and 95% of effective transfer capacity, respectively, with the highest exposure on Tunis-ville–Tunis-nord (ac1).

The 2030 diagnostic case assumes zero prospective imports and no BESS. Of the 29.501 TWh annual demand, 29.395 TWh is served. Domestic primary renewable generation reaches 9.151 TWh (30.24%), while renewable curtailment is 1188.735 GWh and modelled

ENS is 105.535 GWh over 382 h, with a maximum hourly shortfall of 964.6 MW. The case records 389/37 physical-circuit line-hours at or above 90%/95%, and direct domestic operational emissions reach 8.715 $MtCO_2$. These results describe the represented zero-import transition case rather than an unconditional forecast of the 2030 system.

In the 2035 no-BESS reference case, annual demand is 33.300 TWh, of which 33.034 TWh is served. Domestic primary renewable generation reaches 17.907 TWh (52.53%), while fossil generation reaches 16.185 TWh. Renewable curtailment is 1120.263 GWh, and modelled ENS reaches 265.996 GWh over 564 h, with a maximum hourly shortfall of 1527.0 MW. No physical circuit reaches 90% of effective capacity; annual peak loading is 85.7% on Gafsa–Tozeur (ac1). Thus, the annual renewable-energy balance does not imply hourly supply–demand balance.

The hourly decomposition explains how annual shortage and renewable surplus coexist. At the 0.001 MW reporting threshold, modelled ENS and renewable curtailment do not occur in the same hour. During the 564 ENS hours, mean demand is 5.818 GW, mean available VRE is 0.937 GW, thermal dispatch averages 4.530 GW at the represented aggregate ceiling, and maximum internal-circuit loading reaches 81.3%. By contrast, during the 1320 curtailment hours, mean demand is 3.287 GW and mean available VRE is 4.223 GW. The two outcomes therefore arise from distinct temporal regimes: high-demand/low-VRE periods produce scarcity, whereas lower-demand/high-VRE periods produce renewable surplus that is curtailed in the absence of storage. Figure 3 summarises annual generation, renewable curtailment, and modelled ENS across the central cases.

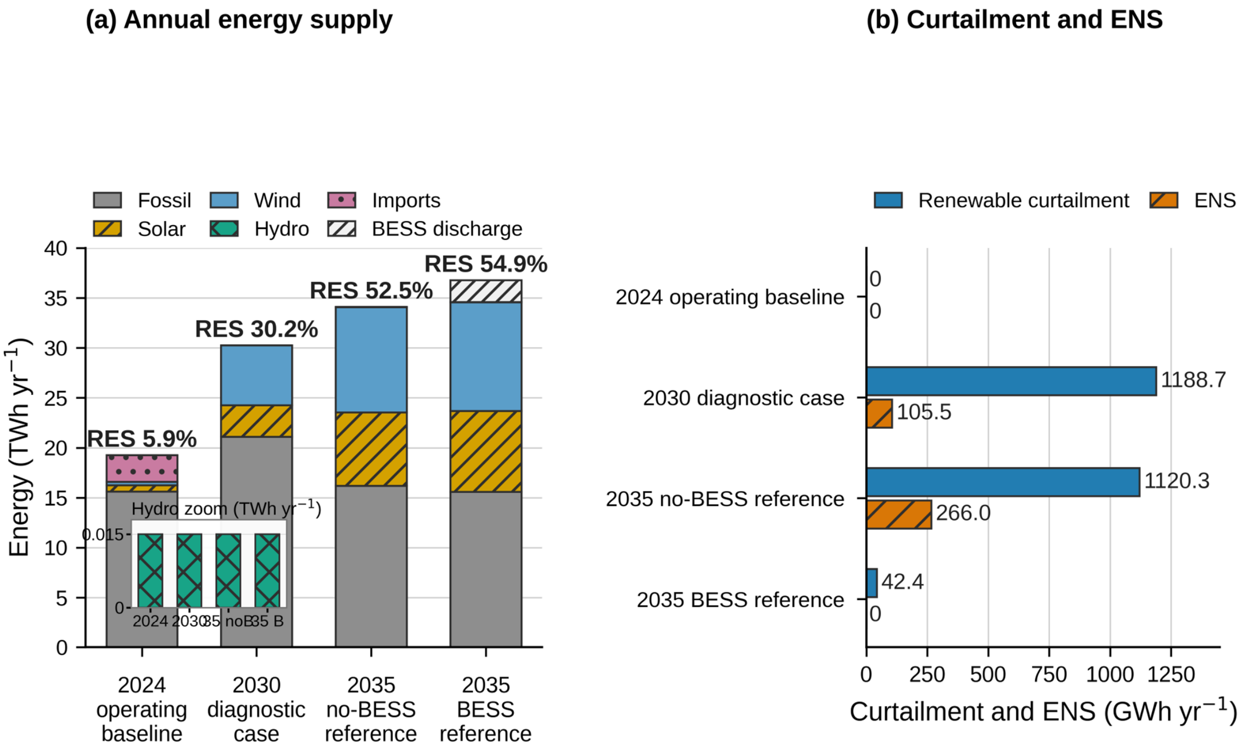


**Figure 3.** Central-case energy outcomes. (**a**) Domestic generation, imports and BESS discharge; (**b**) renewable curtailment and modelled ENS. BESS discharge and imports are excluded from domestic primary renewable generation.

### *3.2. Central BESS Response and Utilisation*

The central assumptions comprise 33.300 TWh annual demand, a four-hour BESS duration, an aggregated BESS cost assumption of 200 kEUR $MW^{-1}$, an assumed VoLL of 10,000 EUR $MWh^{-1}$, the fixed 2035 network, and the defined candidate set. Under these conditions, openTEPES selects 3.590 GW/14.361 GWh of BESS. This model-selected central-case benchmark is neither a prescribed capacity nor a national target. Relative to the matched no-BESS case, modelled ENS falls from 265.996 GWh to zero, and renewable curtailment falls from 1120.263 to 42.362 GWh, a 96.2% reduction. Domestic primary renewable generation increases to 18.985 TWh (54.88%), while fossil generation decreases to 15.605 TWh.

The selected portfolio charges 2428.180 GWh and discharges 2185.362 GWh annually. The discharge-to-charge ratio is 0.90, consistent with the assumed round-trip efficiency, and annual discharge corresponds to 152.2 equivalent full cycles of the selected energy capacity. Figure 4a shows the 168 h interval with the highest gross BESS throughput (model hours 2009–2176; 25 March 16:00 to 1 April 15:00). The independently ranked duration curves in Figure 4b show that substantial charging and discharging also occur outside this interval. Figure 4c summarises annual BESS capacity and utilisation, together with the no-BESS/BESS comparison of curtailment and modelled ENS.

Including the ENS penalty, total modelled cost is 3792.682 MEUR yr$^{-1}$ in the no-BESS case and 1127.495 MEUR yr$^{-1}$ in the BESS case. The assumed VoLL penalty accounts for 2659.958 MEUR yr$^{-1}$ of the no-BESS total. Excluding this penalty, the corresponding costs are 1132.724 and 1127.495 MEUR yr$^{-1}$, respectively, a difference of 5.229 MEUR yr$^{-1}$. The BESS case includes 57.445 MEUR yr$^{-1}$ of annualised storage investment. These values are confined to the model cost boundary defined in Section 2 and do not constitute a levelised cost of storage (LCOS) calculation, a profitability assessment, or an investment-grade estimate. Direct domestic operational emissions decrease from 6.684 to 6.314 $MtCO_2$.

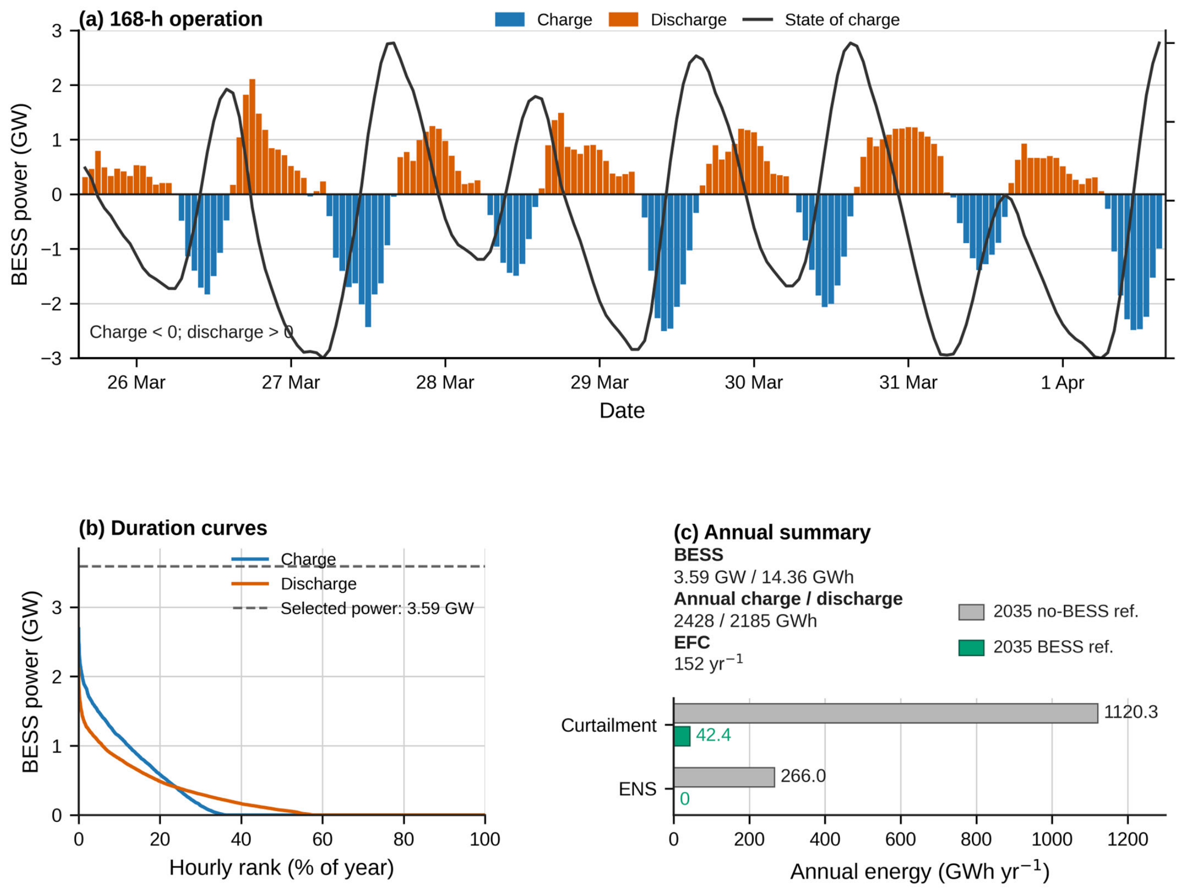


**Figure 4.** BESS operation in the 2035 reference case. (**a**) Maximum-throughput 168 h interval; (**b**) annual charge/discharge duration curves; (**c**) annual capacity and utilisation summary. Charging is plotted below zero.

### *3.3. Residual Transmission Deliverability and Spatial Coupling*

BESS operation redistributes internal active-power flows. The 2035 BESS reference case records 164 and 125 internal physical-circuit line-hours at or above 90% and 95% of effective transfer capacity, respectively, including 105 circuit-hours at the modelled transfer limit. Jerba–Zarzis (ac1) records 110/81 h at or above 90%/95%, Menzel-Temime–Nabeul (ac1) 49/40 h, and Nabeul–Hammamet (ac1) 5/4 h. All three reach 100% peak loading and constitute the leading constrained circuits at both thresholds within the DC/TTC representation.

The increase from zero line-hours at or above 90%/95% in the 2035 no-BESS case to 164/125 in the BESS case illustrates the spatial consequences of temporal balancing. By shifting renewable energy across time at selected nodes, BESS operation alters internal power flows and increases utilisation of specific transfer paths. Compared with the more diffuse Greater Tunis exposure in 2024 and 2030, the 2035 BESS-enabled hotspots are concentrated on southern and north-eastern network interfaces. Figure 5 compares central-case transmission exposure and the leading circuits in the 2035 BESS reference case, Table 4 summarises the central model outputs, and Figure 6 shows the spatial relationship among renewable capacity, model-selected BESS, and the leading circuits.

**Table 4.** Central-case model outputs.

| Indicator | 2024 Operating Baseline | 2030 Diagnostic | 2035 No-BESS Reference | 2035 BESS Reference |
|---|---|---|---|---|
| **Demand (TWh)** | 18.614 | 29.501 | 33.300 | 33.300 |
| **Served demand (TWh)** | 18.614 | 29.395 | 33.034 | 33.300 |
| **Algerian imports (TWh)** | 2.663 | 0 | 0 | 0 |
| **Fossil generation (TWh)** | 15.629 | 21.112 | 16.185 | 15.605 |
| **Primary renewable generation (TWh; share)** | 0.976 (5.87%) | 9.151 (30.24%) | 17.907 (52.53%) | 18.985 (54.88%) |
| **Renewable curtailment (GWh)** | 0 | 1188.735 | 1120.263 | 42.362 |
| **Modelled ENS (GWh; h; peak MW)** | 0; 0; 0 | 105.535; 382; 964.6 | 265.996; 564; 1527.0 | 0; 0; 0 |
| **Selected BESS power/energy (GW/GWh)** | — | — | — | 3.590/14.361 |
| **BESS charge/discharge (GWh)** | — | — | — | 2428.180/2185.362 |
| **Direct domestic operational $CO_2$ emissions ($MtCO_2$)** | 6.030 | 8.715 | 6.684 | 6.314 |
| **Total model cost including ENS penalty ($MEUR\ yr^{-1}$)** | 1017.773 | 2533.548 | 3792.682 | 1127.495 |
| **Model cost excluding ENS penalty ($MEUR\ yr^{-1}$)** | 1017.773 | 1478.197 | 1132.724 | 1127.495 |
| **Annualised BESS investment ($MEUR\ yr^{-1}$)** | 0 | 0 | 0 | 57.445 |
| **Internal line-hours $\geq$90%/$\geq$95% (circuit h $yr^{-1}$)** | 195/39 | 389/37 | 0/0 | 164/125 |

**Note:** BESS = battery energy storage system; ENS = energy not served. Primary renewable generation excludes imports and BESS discharge. Costs are reported with and without the ENS penalty implied by the assumed VoLL. Line-hours are calculated by summing qualifying hours across internal physical circuits and are distinct from system-hours.

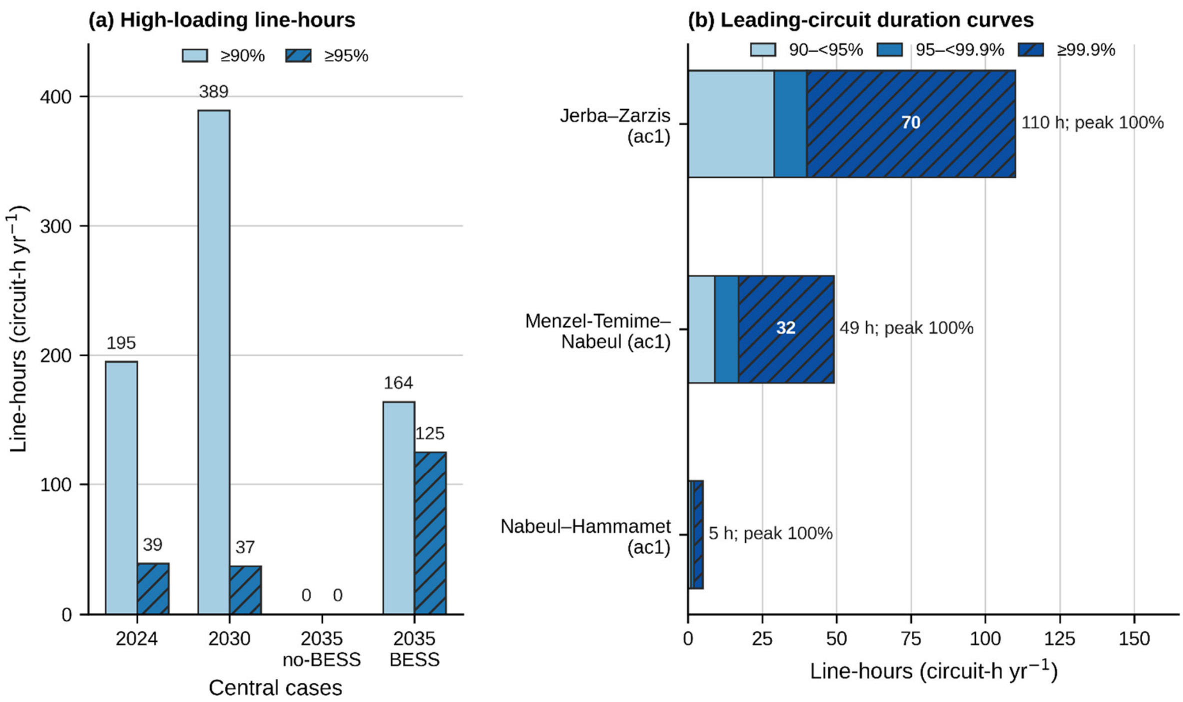


**Figure 5.** Central-case transmission loading. (**a**) Physical-circuit line-hours at or above 90% and 95% of effective transfer capacity; (**b**) loading-duration profiles of the leading circuits in the 2035 BESS reference case.

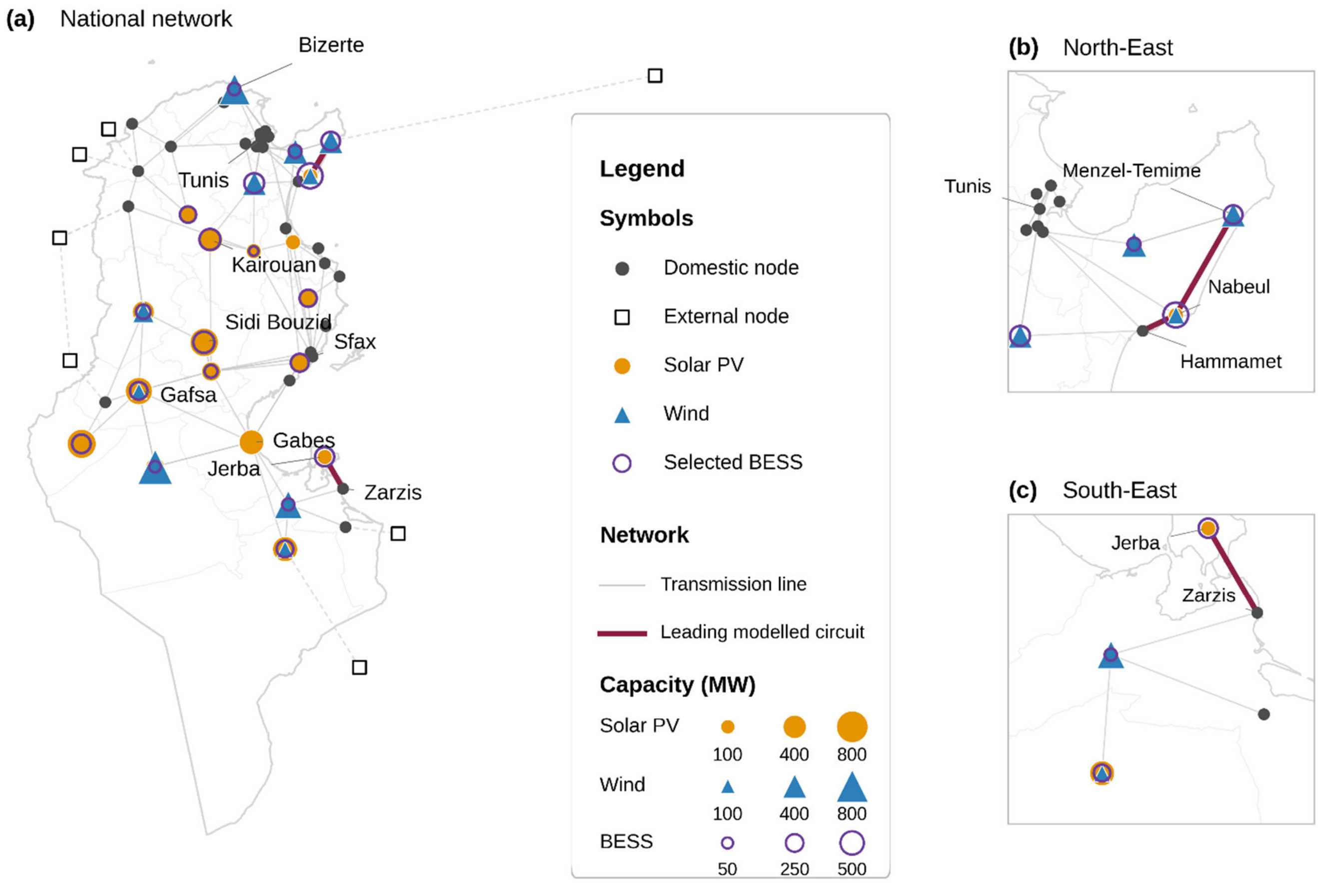


**Figure 6.** Spatial distribution of VRE, BESS, and transmission exposure. (**a**) National network; (**b**) north-eastern detail; (**c**) south-eastern detail. Highlighted corridors denote the leading constraints identified in the DC/TTC screening.

*3.4. Deterministic Sensitivity Responses*

The eight sensitivity families produce distinct economic, operational, network, and spatial responses. Figure 7 reports the maximum absolute deviation from the 2035 BESS reference case within each deterministic family. The figure is a compact response matrix rather than a probabilistic or composite stability metric. For S4, the normalisation includes only BESS-enabled configurations, and the S6 network cell is omitted because S6 reports line-hours at or above 99%, rather than 95%, of effective capacity. BESS remains selected in every BESS-enabled sensitivity case, although its quantity, duration, and location vary substantially across the tested option set.

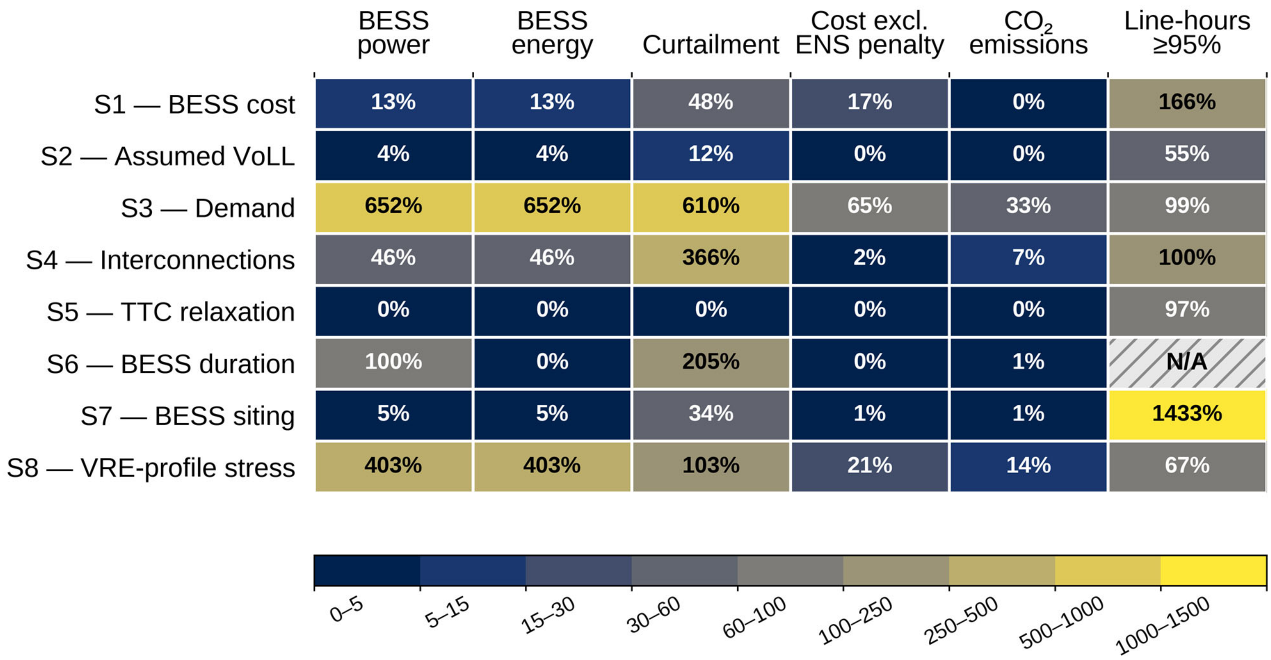


**Figure 7.** Cross-sensitivity response relative to the 2035 BESS reference case. Cells report the maximum absolute deviation within each deterministic sensitivity family.

3.4.1. Economic Assumptions and Imposed BESS Duration

The model-selected capacity changes only marginally as the aggregated BESS cost assumption increases from 200 to 400 kEUR $MW^{-1}$: selected power decreases from 3.590 to 3.585 GW, energy decreases from 14.361 to 14.340 GWh, and modelled ENS remains zero. A clearer transition occurs between 400 and 600 kEUR $MW^{-1}$. At 600 kEUR $MW^{-1}$, selected BESS falls to 3.456 GW and modelled ENS reaches 0.459 GWh. At 1000 kEUR $MW^{-1}$, selected BESS is 3.141 GW/12.564 GWh, modelled ENS reaches 2.710 GWh, curtailment reaches 62.702 GWh, and line-hours at or above 95% of effective capacity increase from 125 to 333. S1 therefore identifies a transition within the represented power-based cost assumption rather than a complete life-cycle cost threshold.

The response to the assumed VoLL is concentrated at the lower end of the tested range. From 5000 to 50,000 EUR $MWh^{-1}$, selected BESS remains close to 3.590 GW/14.361 GWh and modelled ENS remains zero. At 2000 EUR $MWh^{-1}$, selected BESS falls to 3.460 GW/13.841 GWh and modelled ENS reaches 0.481 GWh. This response reflects the assumed scarcity penalty; objective values obtained under different VoLL assumptions are not directly comparable as welfare measures.

The imposed-duration sensitivity reveals contrasting responses in selected power and energy. Energy capacity remains close to 14.36 GWh, while selected power decreases from 7.180 GW at 2 h to 3.590, 2.394, 1.798, and 1.438 GW at 4, 6, 8, and 10 h, respectively.

Curtailment increases to 65.799 GWh at 8 h and 129.140 GWh at 10 h; the 10 h case also records 0.152 GWh of modelled ENS. Within the represented cost formulation, longer imposed durations therefore reduce selected power but can constrain short-duration flexibility.

### 3.4.2. Demand and Deterministic VRE-Profile Stress

Demand scaling produces the largest selected BESS capacity response among the scalar sensitivity families. At 30.0 TWh, the model selects 2.243 GW/8.971 GWh with zero modelled ENS. At 36.63 TWh, the full 27 GW/108 GWh candidate portfolio is selected, yet 4.103 GWh of modelled ENS remains. At 38.3 TWh, the same candidate-domain ceiling remains binding, modelled ENS rises to 205.982 GWh, and line-hours at or above 95% of effective capacity reach 244. These high-demand cases therefore represent candidate-saturation boundaries under fixed generation, network, and import assumptions.

Selected BESS capacity is also sensitive to the prescribed VRE profiles. A 10% reduction in combined VRE availability increases selected BESS capacity to 4.726 GW/18.905 GWh, while the synthetic 168 h low-VRE stress increases it to 18.067 GW/72.268 GWh. Conversely, a 10% increase in wind availability reduces selected BESS capacity to 3.434 GW/13.737 GWh, although curtailment rises to 85.966 GWh. These responses characterise deterministic perturbations of the reference VRE chronology rather than probabilities associated with multi-year weather variability. Figure 8 shows the demand and VRE-profile responses across the full BESS power–energy domain and provides an enlarged view of the reference region.

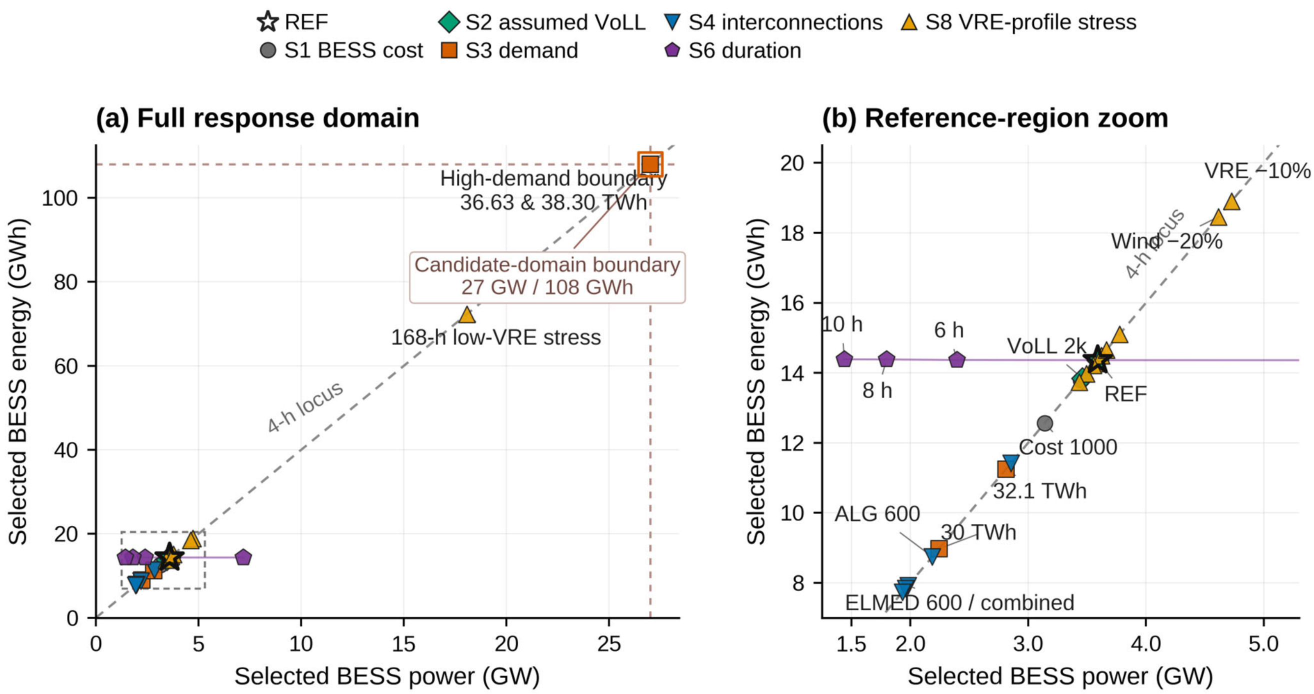


**Figure 8.** BESS power–energy response across deterministic sensitivities. (**a**) Full response domain; (**b**) reference-region zoom. The dashed line denotes the 4 h power–energy relation. The purple line connects the S6 duration-sensitivity cases; the 27 GW/108 GWh boundary reflects the candidate-domain ceiling.

### 3.4.3. Interconnection, Targeted TTC Relaxation and Siting

Stylised interconnection availability reduces model-selected BESS capacity, while the network response depends on the location of the available import path. With 600 MW available from both Algeria and ELMED, selected BESS capacity falls to 1.933 GW/7.733 GWh, imports reach 0.953 TWh, and direct domestic operational emissions fall to 5.900 $MtCO_2$.

Renewable curtailment rises to 197.498 GWh, reflecting the associated change in domestic dispatch. The corresponding no-BESS case retains 10.113 GWh of modelled ENS. The ELMED-only BESS case records 160 line-hours at or above 95% of effective capacity, compared with 0 for Algeria-only availability and 18 for combined availability. These cases represent stylised import-availability assumptions and exclude interconnector CAPEX, foreign-system adequacy, market and outage availability, and emissions associated with imported electricity.

Targeted TTC relaxation primarily reduces transmission exposure. Increasing the limits of Jerba–Zarzis and Menzel-Temime–Nabeul by 50% reduces line-hours at or above 90%/95% from 164/125 to 6/5, while selected BESS remains 3.590 GW/14.361 GWh, modelled ENS remains zero, and curtailment is 42.292 GWh. Doubling the same limits reduces the total number of line-hours at or above 95% by only one additional circuit-hour. The incremental network relief beyond the $\times$1.50 case is therefore marginal within this direct capacity-relaxation experiment.

Across the eight S7 candidate domains, modelled ENS remains zero and selected BESS ranges from 3.590 to 3.760 GW, whereas line-hours at or above 95% range from 6 for the case oriented towards renewable energy sources (RES-oriented siting) to 1916 in the North-West boundary case. Coastal-load siting yields the lowest curtailment, at 38.342 GWh, but records 268 line-hours at or above 95%; the mixed domain reduces this exposure to 34 line-hours at near-reference cost. Aggregate BESS capacity therefore varies over a much narrower range than transmission exposure. The North-West boundary combines strong geographic concentration with only 240.1 MW of candidate headroom. Figure 9 compares transmission exposure across representative flexibility cases and S7 siting domains, while Table 5 summarises the deterministic response ranges and their interpretation boundaries.

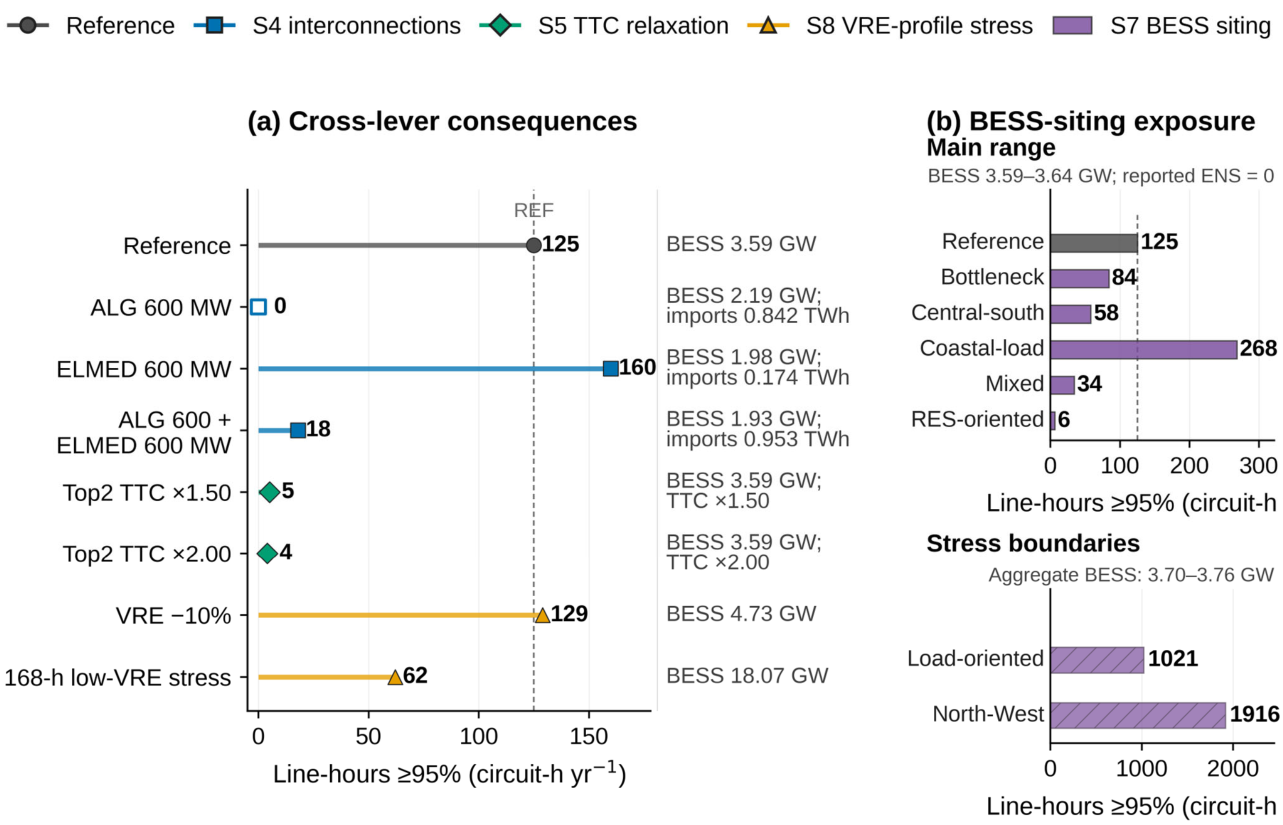


**Figure 9.** Transmission exposure across flexibility sensitivities. (**a**) Representative interconnection, TTC-relaxation and VRE-profile cases; (**b**) BESS-siting domains. Values denote physical-circuit line-hours at or above 95% of effective transfer capacity.

**Table 5.** Deterministic cross-sensitivity response summary and interpretation boundaries.

| Family/Tested Lever | Model-Selected BESS Response | Main System Response | Interpretation and Boundary |
|---|---|---|---|
| **S1**—BESS cost 150–1000 kEUR MW$^{-1}$ | 3.590 GW at 200; 3.141 GW/ 12.564 GWh at 1000 | ENS remains zero through 400 kEUR MW$^{-1}$; reaches 2.710 GWh at 1000 kEUR MW$^{-1}$, with 62.702 GWh curtailment and 333 line-hours $\geq$ 95% | Limited response through 400 kEUR MW$^{-1}$; transition emerges between 400 and 600 kEUR MW$^{-1}$. Simplified power-based cost proxy |
| **S2**—assumed VoLL 2000–50,000 EUR MWh$^{-1}$ | 3.460 GW/13.841 GWh at 2000 EUR MWh$^{-1}$; near-reference values at $\geq$5000 EUR MWh$^{-1}$ | ENS = 0.481 GWh at 2000 EUR MWh$^{-1}$ and zero at $\geq$5000 EUR MWh$^{-1}$ | Response concentrated at the lower end of the tested range. VoLL is an assumed scarcity penalty, not an empirically derived Tunisian valuation |
| **S3**—annual demand 30.0–38.3 TWh | 2.243 GW/8.971 GWh at 30.0 TWh; candidate ceiling of 27 GW/108 GWh at 36.63 and 38.3 TWh | ENS = 0, 4.103, and 205.982 GWh at 30.0, 36.63, and 38.3 TWh, respectively; line-hours $\geq$ 95% reach 244 at 38.3 TWh | Largest BESS-capacity response; candidate-domain saturation under fixed generation, network, and import assumptions |
| **S4**—Algeria/ELMED availability up to 600 MW each | Combined case: 1.933 GW/ 7.733 GWh | BESS-enabled cases: ENS = 0; matched no-BESS case: ENS = 10.113 GWh. Line-hours $\geq$ 95%: Algeria 0; ELMED 160; combined 18 | Stylised import availability reduces selected domestic BESS but produces point-of-entry-dependent effects on the network |
| **S5**—targeted TTC relaxation $\times$1.50 and $\times$2.00 on the two leading circuits | $\approx$3.590 GW/14.361 GWh | ENS = 0; curtailment = 42.292 GWh at $\times$1.50; $\geq$95% line-hours: 125 $\rightarrow$ 5 $\rightarrow$ 4 | Large reduction in transmission exposure with essentially unchanged BESS selection; little additional relief beyond $\times$1.50 |
| **S6**—BESS duration 2–10 h | Energy remains $\approx$ 14.36 GWh; power decreases from 7.180 to 1.438 GW | Curtailment reaches 129.140 GWh and ENS 0.152 GWh at 10 h | Power–energy trade-off under imposed duration; MW and MWh costs are not independently co-optimised |
| **S7**—candidate-node domain: eight siting configurations | 3.590–3.760 GW; 3–19 active nodes | ENS = 0; curtailment 38.342–56.763 GWh; $\geq$95% line-hours 6–1916 | Narrow aggregate-capacity range but wide spatial response; candidate domains differ in eligibility and available headroom |
| **S8**—VRE-profile stress: PV/wind annual scalings + synthetic 168 h low-VRE stress | 3.434 GW/13.737 GWh to 18.067 GW/72.268 GWh across the tested cases | $\geq$95% line-hours = 129 for VRE $-$10% and 62 for the 168 h stress; curtailment also depends on the prescribed transformation | Renewable availability and stress duration materially affect BESS selection; results derive from a single deterministic chronology |

**Note:** BESS = battery energy storage system; ENS = energy not served; TTC = total transfer capacity; VRE = variable renewable energy; VoLL = value of lost load. Values summarise deterministic responses within the tested sensitivity families and do not represent probabilities, statistical confidence intervals, or investment requirements.

### *3.5. Nodal Recurrence and Transmission Consequences*

Across 47 BESS-enabled cases with comparable nodal outputs, Bizerte is selected in 46 cases (97.9%). Sidi Bouzid, Kairouan, Sfax-sud, Gafsa, and Menzel-Bouzelfa are each selected in 44 cases (93.6%), while Nabeul is selected in 43 cases (91.5%) and has the highest conditional mean selected power, at 506.6 MW. Sousse and Gabes illustrate the distinction between recurrence and conditional size: they are selected in only 9/47 and 8/47 cases, respectively, but have conditional mean selected powers of 451.1 and 335.1 MW. These frequencies describe recurrence across the tested deterministic cases rather than investment probabilities; S6 is excluded because comparable nodal outputs are unavailable.

In the central 2035 BESS case, the 3.590 GW portfolio is distributed across 19 active nodes, with the largest allocations at Nabeul (498.7 MW), Sidi Bouzid (339.2 MW), Kairouan (334.3 MW), Zaghouan (289.1 MW), and Jerba (263.3 MW). Candidate-domain restrictions can reduce the number of active nodes to three while maintaining zero modelled ENS, although curtailment, cost, and transmission exposure change substantially. Kairouan and Kairouan-nord are treated as distinct nodes throughout the nodal analysis. Figure 10 distinguishes node-selection recurrence from conditional mean selected BESS power, while Table 6 summarises the recurrence results and representative siting and TTC-relaxation consequences.

Siting also changes which circuits are most exposed. In the central 2035 BESS case, the leading high-loading circuits are Jerba–Zarzis, Menzel-Temime–Nabeul, and Nabeul–Hammamet, whereas the coastal-load, load-oriented, and North-West candidate domains shift exposure to different network interfaces. A 50% targeted TTC relaxation of the two leading reference-case corridors reduces line-hours at or above 95% from 125 to 5 without materially changing aggregate BESS capacity. The number, location, and loading intensity of highly exposed circuits are therefore conditional on the spatial flexibility configuration.

Across the tested cases, BESS remains selected within the represented option set, but its quantity, duration, and location vary substantially. Demand and deterministic VRE-profile stress produce the widest capacity responses, specified interconnection availability reduces selected BESS capacity, and targeted TTC relaxation and siting primarily reshape transmission exposure. These results define deterministic response ranges under the stated assumptions rather than statistical confidence intervals or procurement requirements.

**Table 6.** Nodal BESS recurrence and representative spatial consequences.

**(a) Cross-Family Nodal Recurrence**

| Node(s) | Selection Recurrence | Conditional Mean BESS Power (MW) | Interpretation |
|---|---|---|---|
| **Bizerte** | 46/47 cases (97.9%) | 163.3 | Most recurrent node across the tested BESS-enabled cases |
| **Sidi Bouzid; Kairouan; Sfax-sud; Gafsa; Menzel-Bouzelfa** | 44/47 cases each (93.6%) | 165.4–377.7 | Recurrent multi-node core; allocations remain case-dependent |
| **Nabeul** | 43/47 cases (91.5%) | 506.6 | High recurrence and the highest conditional mean power among the most recurrent nodes |

**(b) Representative Siting and TTC-Relaxation Cases**

| Configuration | Selected BESS Power (GW) | Active Nodes/ Domain | Curtailment (GWh) | Line-Hours ≥ 95% | Spatial Interpretation |
|---|---|---|---|---|---|
| **Reference—** *TN2035_B_REF* | 3.590 | 19 | 42.362 | 125 | Leading transmission exposure on Jerba–Zarzis, Menzel-Temime–Nabeul, and Nabeul–Hammamet |
| **S7—RES-oriented** | 3.634 | 13 | 41.827 | 6 | Lowest transmission exposure; not the minimum-curtailment case |
| **S7—Coastal-load** | 3.641 | 9 | 38.342 | 268 | Lowest curtailment, but substantially higher transmission exposure |
| **S7—Mixed** | 3.602 | 17 | 42.112 | 34 | Near-reference curtailment with lower transmission exposure |
| **S7—North-West** | 3.760 | 3 | 56.763 | 1916 | Geographic concentration and candidate-headroom constraint; only 240.1 MW of candidate headroom remains |
| **S5—Top-two TTC ×1.50** | 3.590 | Reference domain | 42.292 | 5 | Strong relief of the two leading reference-case corridors with negligible change in aggregate BESS capacity |

**Note:** BESS = battery energy storage system; RES = renewable energy sources; TTC = total transfer capacity. Selection recurrence is calculated across 47 BESS-enabled cases with comparable nodal outputs and is descriptive rather than probabilistic; S6 is excluded because comparable nodal outputs are unavailable. Line-hours are annual physical-circuit hours at or above 95% of effective transfer capacity.

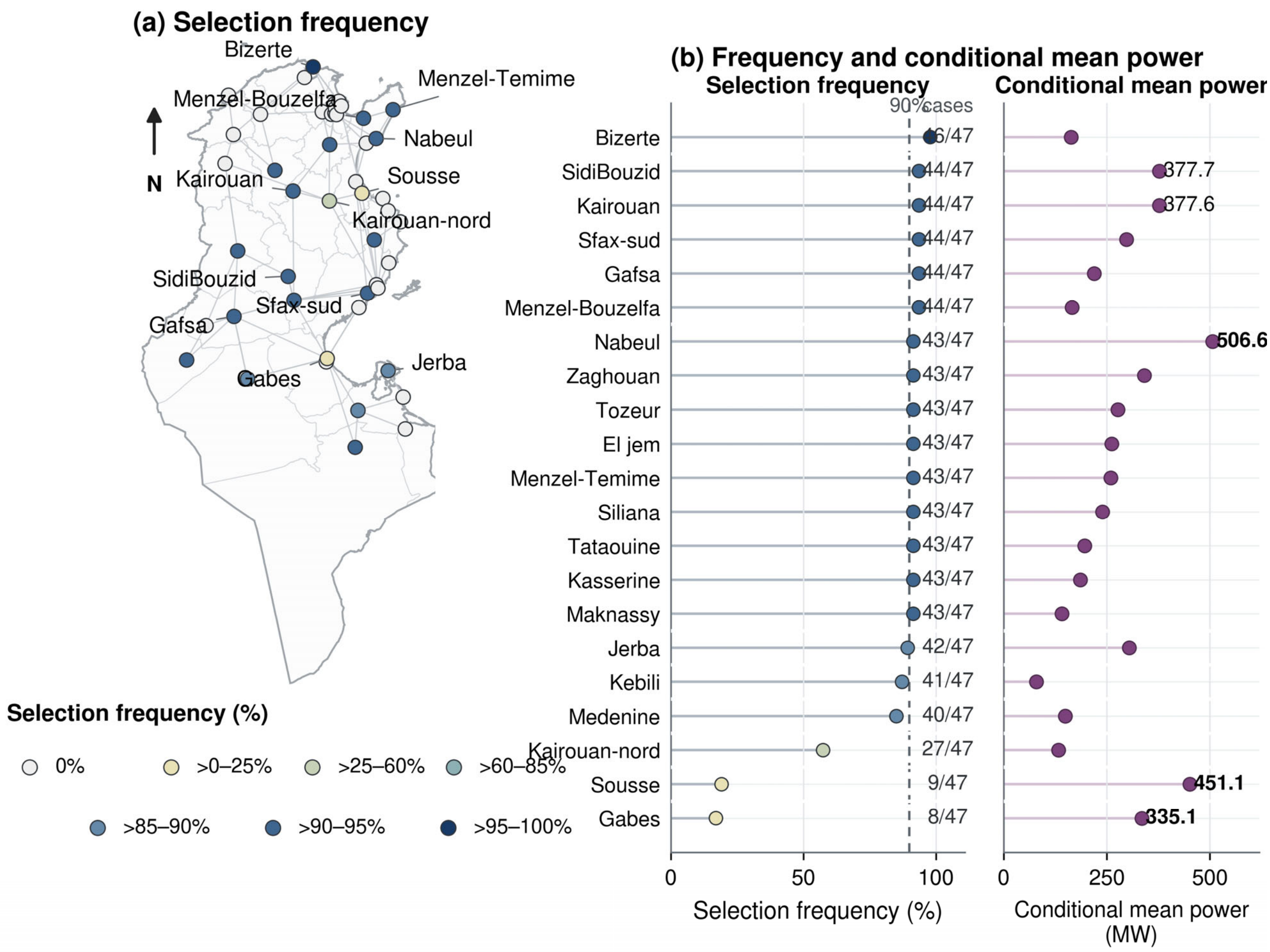


**Figure 10.** BESS siting recurrence across deterministic sensitivities. (**a**) Node-selection frequency; (**b**) selection frequency and conditional mean selected BESS power. Frequencies indicate recurrence across the tested deterministic cases, not investment probabilities.

# 4. Discussion

## *4.1. What the Chronological and Nodal Representation Adds*

The central comparison shows why annual renewable-energy availability cannot be equated with hourly deliverability. In the 2035 no-BESS reference case, 265.996 GWh of modelled ENS and 1120.263 GWh of renewable curtailment occur in disjoint sets of hours at the 0.001 MW reporting threshold. During ENS hours, demand is higher and VRE availability is lower, whereas curtailment occurs under lower-demand, higher-VRE conditions. The coexistence of annual shortage and surplus therefore reflects a temporal mismatch between scarcity and renewable availability rather than simultaneous network congestion during shortage.

The nodal representation adds a spatial dimension that cannot be recovered from an annual balance or copper-plate model. Enabling BESS eliminates modelled ENS under the represented deterministic conditions and sharply reduces curtailment, but also redistributes charging and discharging across the network. Consequently, physical-circuit line-hours at or above the 90% and 95% thresholds increase from zero at both thresholds to 164 and 125, respectively, with Jerba–Zarzis, Menzel-Temime–Nabeul, and Nabeul–Hammamet emerging as the leading interfaces. The siting sensitivities reinforce this result: aggregate BESS selection remains within 3.590–3.760 GW across the eight S7 candidate domains, whereas line-hours at or above 95% range from 6 to 1916. Similar national storage volumes can therefore produce markedly different nodal and transmission consequences.

This joint temporal–spatial assessment is the main incremental contribution relative to existing Tunisia- and Maghreb-focused transition studies [15–20]. Those studies examine technology pathways, policy, and regional exchange, whereas the present analysis identifies when modelled shortage and curtailment occur and how storage operation changes transmission exposure. The contribution is therefore a network-constrained planning assessment rather than an operational-security certification: modelled ENS, curtailment, storage operation, and circuit loading are evaluated within a common chronological and nodal framework. This interpretation is consistent with the broader literature showing that renewable-system planning is sensitive to both chronology and network representation [1–4,8].

### 4.2. Conditional Role and Economic Interpretation of BESS

Within the represented expansion space, BESS is selected in every BESS-enabled sensitivity case. This persistence indicates a role for temporal flexibility under the tested assumptions, but does not imply a fixed national storage requirement. The central selection of 3.590 GW/14.361 GWh is conditional on 33.300 TWh annual demand, a four-hour duration, an aggregated BESS cost assumption of 200 kEUR $MW^{-1}$, an assumed VoLL of 10,000 EUR $MWh^{-1}$, the fixed 2035 network, the prescribed generation fleet, and the admissible candidate set. Demand and adverse VRE-profile stresses produce the widest capacity responses, while duration, import availability, and siting alter the power–energy balance, aggregate storage requirement, and spatial allocation. The central value is therefore a scenario-conditioned benchmark rather than a procurement target.

Several sensitivity families remain close to the central benchmark under nearby assumptions, but selected capacity changes materially when the balancing requirement or candidate domain changes. Because the analysis is deterministic and based on a single reference chronology, no statistical confidence interval is meaningful for the 3.590 GW/14.361 GWh result. The evidence therefore supports conditional persistence of storage selection, not invariance of the exact capacity: the required MW, MWh, and nodal allocation remain contingent on future demand, renewable availability, network development, and competing flexibility options.

The economic comparison is bounded by the simplified model representation. Excluding the ENS penalty, the 2035 no-BESS and BESS cases differ by only 5.229 MEUR $yr^{-1}$; including the ENS term makes the comparison largely a valuation of avoided modelled shortage. These results therefore do not establish merchant profitability, levelised cost of storage, or an investment-grade business case. The BESS cost representation is an aggregated power-based proxy and does not separately represent energy-capacity CAPEX, degradation, replacement and augmentation, fixed operation and maintenance, residual value, financing, or market revenues. A complete lifetime-cost assessment would require additional treatment of cost trajectories and degradation [26,27]. Likewise, the assumed VoLL sensitivity tests the model trade-off between storage expenditure and unserved energy rather than an empirically estimated Tunisian consumer valuation [29]. The reported 152.2 equivalent full-discharge cycles quantify operational utilisation rather than project profitability.

The asymmetry between endogenous BESS and exogenous transmission is deliberate: the matched central comparison isolates storage within a prescribed 2035 topology. However, this design also limits the economic interpretation. Joint expansion could introduce new generation, demand-side flexibility, candidate transmission projects, and interconnection investment as competing or complementary options, potentially changing both the quantity and location of selected storage. The targeted TTC-relaxation cases therefore indicate the consequences of additional transfer capability but do not identify an economically optimal transmission portfolio. The central BESS benchmark remains conditional on the represented expansion space.

### 4.3. Temporal, Spatial and External Flexibility Are Complementary

The cross-lever results support a functional interpretation of flexibility. BESS shifts energy across time, internal transmission transfers it across locations, and interconnections provide external energy at specific points of entry. These functions interact but are not interchangeable [3,4,8,9]. In the central BESS case, temporal shifting reduces modelled ENS and renewable curtailment while increasing utilisation of selected internal transfer paths. Additional temporal flexibility can therefore reveal spatial deliverability constraints rather than eliminate them.

The targeted TTC-relaxation cases isolate this spatial effect. Increasing the limits of the two leading reference-case circuits by 50% reduces line-hours at or above 95% from 125 to 5, while selected BESS remains approximately 3.590 GW/14.361 GWh and modelled ENS remains zero. Doubling the same limits provides only marginal additional relief within this simplified screening exercise. These results identify interfaces where additional transfer capability may be valuable, but route design, capital cost, phasing, constructability, outage scheduling, voltage performance, and contingency security remain outside the analysis. The recurrent circuits therefore indicate priorities for detailed engineering assessment rather than validated reinforcement projects.

The interconnection sensitivities illustrate a different form of flexibility. With stylised availability of 600 MW from Algeria and 600 MW through ELMED, selected domestic BESS falls to 1.933 GW/7.733 GWh; however, the matched no-BESS case still records 10.113 GWh of modelled ENS. Algeria-only, ELMED-only, and combined availability also produce different internal high-loading patterns, showing that the point of entry matters alongside the amount of imported energy. These cases quantify the response to specified import availability; they do not establish dependable import contribution because foreign-system adequacy, coincident regional stress, market access, interconnector outages, investment costs, and emissions associated with imported electricity are not represented [28].

Siting introduces a further spatial trade-off. Restricting candidate domains changes curtailment, cost, and circuit exposure far more than aggregate selected BESS capacity. The recurrent multi-node core, including Bizerte's selection in 46 of 47 comparable cases, identifies locations that remain relevant across many tested scenarios, but recurrence is descriptive rather than probabilistic. Conversely, the North-West boundary case combines geographic concentration with only 240.1 MW of candidate headroom and therefore does not support a general conclusion about BESS value in that region. Coordinated storage-connection and network studies should combine these nodal screening results with land availability, connection capacity, and project-cost information [25], together with subsequent AC load-flow analysis [11] and, where required, dedicated contingency, short-circuit, protection, and dynamic studies.

### 4.4. Deterministic Sensitivities and Adaptive Planning Implications

The eight sensitivity families identify the assumptions that most strongly affect the model response. Demand produces the widest capacity response: at 36.63 and 38.3 TWh, the full 27 GW/108 GWh candidate domain binds while modelled ENS remains positive. This saturation is a diagnostic boundary rather than a storage recommendation. Under fixed generation, network, and import assumptions, storage alone is no longer sufficient to meet the additional balancing requirement. The result therefore points to joint reconsideration of the generation portfolio, demand-side flexibility, network capability, imports, and the candidate domain. Lower curtailment at high demand should likewise not be interpreted as improved flexibility, because greater demand absorbs surplus in some hours while deepening deficits in others.

The VRE-profile sensitivities require the same bounded interpretation. A 10% reduction in combined VRE availability increases selected BESS to 4.726 GW/18.905 GWh, while the synthetic 168 h low-VRE stress increases it to 18.067 GW/72.268 GWh. These cases show sensitivity to the magnitude and duration of low-VRE conditions, but they are transformations of a single reference chronology rather than a multi-year weather assessment. They therefore define deterministic stress boundaries rather than event probabilities or return periods. Correlated weather years, temperature-sensitive demand, forced outages, maintenance, reserve deployment, and interconnection scarcity could alter the magnitude, location, and technology mix of flexibility; their combined effects cannot be inferred from the present deterministic cases alone [21–24].

For planning purposes, the results support a staged and adaptive use of the model outputs. The central benchmark can guide the scale and location of subsequent studies, while recurrent nodes and high-loading interfaces identify priorities for connection and network assessment. Future updates can track demand level and shape, renewable chronology, candidate headroom, modelled ENS, curtailment, BESS utilisation, interconnection availability, and circuit-loading duration. Material departures from the reference assumptions should trigger re-optimisation of the flexibility portfolio rather than automatic scaling of the central BESS quantity.

The methodological implication extends beyond Tunisia. Emerging power systems with rapidly increasing VRE can apply a similar combination of chronological, nodal, and network-constrained sensitivity analysis to distinguish temporal scarcity from spatial deliverability. The numerical capacities, recurrent nodes, and stressed interfaces remain specific to the represented Tunisian scenarios. What is transferable is the planning logic: annual renewable shares, hourly balance, and spatial transfer capability should be evaluated jointly, with model-selected quantities interpreted within the option set and scenario boundaries that produced them.

## 5. Conclusions, Limitations and Future Work

### 5.1. Conclusions

This study applied openTEPES to a deterministic 8736 h, 47-node representation of Tunisia's prospective power system to assess renewable integration, modelled ENS, endogenous BESS selection, and transmission deliverability. Four central cases and eight deterministic sensitivity families were evaluated. The framework links aggregate transition-pathway analysis with more detailed probabilistic adequacy, AC-security validation, and project-level investment studies.

The matched 2035 comparison shows that annual renewable availability alone does not ensure deliverable electricity. At 33.300 TWh annual demand, the no-BESS reference case records 265.996 GWh of modelled ENS and 1120.263 GWh of renewable curtailment in disjoint hours. Enabling BESS leads to a central selection of 3.590 GW/14.361 GWh, reduces modelled ENS to zero under the represented deterministic conditions, and lowers curtailment to 42.362 GWh. These results indicate a strong role for temporal flexibility within the represented option set, while the exact storage quantity remains conditional on the adopted assumptions.

The nodal analysis shows that temporal balancing and spatial deliverability are closely coupled. The BESS reference case records 164 and 125 physical-circuit line-hours at or above the 90% and 95% thresholds, respectively, compared with zero at both thresholds in the matched no-BESS case; across the S7 siting domains, line-hours at or above 95% range from 6 to 1916. A 50% TTC relaxation of the two leading circuits reduces line-hours at or above 95% from 125 to 5 with negligible change in aggregate BESS capacity. Stylised Algerian and ELMED availability reduces selected domestic BESS under the tested assumptions but does not establish dependable import contribution. Storage, internal transmission, and cross-border exchange therefore address complementary dimensions of renewable integration.

Across the sensitivity programme, demand and deterministic VRE-profile stress produce the widest storage-capacity responses, while imposed duration, interconnection availability, and siting restrictions alter storage power, energy, and spatial allocation. The central 3.590 GW/14.361 GWh selection is therefore interpreted as a conditional planning benchmark rather than a national target or adequacy requirement. The broader methodological implication is that renewable-integration assessments benefit from combining hourly chronology with nodal network representation and from distinguishing scenario-conditioned model outputs from investment recommendations.

### *5.2. Limitations and Future Work*

The first limitation concerns temporal uncertainty. The analysis relies on a single 8736 h reference chronology and deterministic perturbations rather than a multi-year probabilistic representation. It excludes spatially correlated weather years, forced-outage sampling, chronological maintenance, operating reserves, demand response, and probabilistic adequacy metrics such as loss-of-load expectation (LOLE), expected energy not served (EENS), and effective load-carrying capability (ELCC). A priority extension is therefore a multi-year nodal assessment combining weather-dependent demand and VRE production with unit and network contingencies, maintenance, reserve requirements, and scenario-dependent interconnection availability [21–24,28].

Second, the DC/TTC network representation is an active-power planning screen. It does not establish AC feasibility, voltage or reactive-power performance, short-circuit behaviour, protection coordination, dynamic stability, or $N-1$ security. The recurrent nodes and stressed circuits identified here warrant subsequent connection studies and AC load-flow analysis [11], followed, where appropriate, by dedicated contingency, short-circuit, protection, and dynamic studies before project-level decisions.

Third, the investment and economic boundary is deliberately limited. BESS is endogenous, whereas new generation, demand-side flexibility, transmission projects, and interconnector investment are not co-optimised. The BESS formulation omits separate MW and MWh cost components, degradation, replacement and augmentation, fixed operation and maintenance, residual value, financing, and market revenues. Future work should co-optimise storage with generation, demand-side flexibility, candidate transmission projects, and interconnection using consistent life-cycle cost, emissions, and reliability boundaries. Relevant extensions include network-aware storage siting [25], richer storage cost and degradation modelling [26,27], and multi-region adequacy treatment of interconnection [28].

Finally, the demand sensitivities scale a single load shape, while the VRE sensitivities transform a single reference chronology. Sector-specific electrification, temperature-sensitive demand, behavioural change, and compound high-demand/low-VRE/outage events are not represented. Extending the framework along these dimensions would provide a stronger basis for subsequent investment-grade studies. Within its stated scope, the present analysis provides a coherent deterministic assessment of the mechanisms linking modelled ENS, renewable curtailment, storage selection, and transmission deliverability, while identifying the additional analyses required to progress from planning screening to project validation.

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## Appendix A

This appendix provides detailed input definitions for the S7 BESS-siting and S8 VRE-profile sensitivities and summarises the data sources and model representation used in the study. Appendix A.1 defines the admissible BESS candidate domains, candidate counts, and aggregate pre-optimisation ceilings used in S7. Appendix A.2 specifies the PV and wind availability transformations, temporal domains, and bounding rules used in S8. Appendix A.3 summarises the numerical representation, source or modelling basis, and treatment of the principal data components. These tables document scenario inputs and model representation; Section 3 reports the investment and operational outcomes.

### *Appendix A.1. S7 BESS-Siting Candidate Domains*

**Table A1.** Candidate-node definitions for the S7 BESS-siting sensitivity.

| Configuration | Eligible Domestic Nodes | Eligible Nodes/ Candidate Options | Aggregate Candidate Ceiling (GW/GWh) |
|---|---|---|---|
| **Reference** *TN2035_B_REF* | Bizerte; El Jem; Gabes; Gafsa; Jerba; Kairouan; Kairouan-nord; Kasserine; Kebili; Maknassy; Medenine; Menzel-Bouzelfa; Menzel-Temime; Nabeul; Sfax-sud; Sidi Bouzid; Siliana; Sousse; Tataouine; Tozeur; Zaghouan | 21/27 | 27.000/108.000 |
| **Unrestricted S7 control (*Site_All*)** *TN2035_B_Site_All* | Bizerte; El Jem; Gabes; Gafsa; Jerba; Kairouan; Kairouan-nord; Kasserine; Kebili; Maknassy; Medenine; Menzel-Bouzelfa; Menzel-Temime; Nabeul; Sfax-sud; Sidi Bouzid; Siliana; Sousse; Tataouine; Tozeur; Zaghouan | 21/27 | 27.000/108.000 |
| **Bottleneck-oriented** *TN2035_B_Site_Bottleneck* | Bizerte; El Jem; Gabes; Gafsa; Kairouan; Kairouan-nord; Kasserine; Maknassy; Sfax-sud; Sidi Bouzid; Siliana; Sousse | 12/14 | 14.000/56.000 |
| **Central-south** *TN2035_B_Site_CentralSouth* | El Jem; Gabes; Gafsa; Jerba; Kairouan; Kairouan-nord; Kasserine; Kebili; Maknassy; Medenine; Sfax-sud; Sidi Bouzid; Tataouine; Tozeur | 14/19 | 19.000/76.000 |
| **Coastal-load** *TN2035_B_Site_CoastalLoad* | Bizerte; Gabes; Jerba; Medenine; Menzel-Bouzelfa; Menzel-Temime; Nabeul; Sfax-sud; Sousse | 9/11 | 11.000/44.000 |

**Table A1.** *Cont.*

| Configuration | Eligible Domestic Nodes | Eligible Nodes/ Candidate Options | Aggregate Candidate Ceiling (GW/GWh) |
|---|---|---|---|
| **Load-oriented** *TN2035_B_Site_Load* | Bizerte; Menzel-Bouzelfa; Nabeul; Sousse; Zaghouan | 5/6 | 6.000/24.000 |
| **Mixed** *TN2035_B_Mixed* | Bizerte; El Jem; Gabes; Gafsa; Kairouan; Kairouan-nord; Kasserine; Kebili; Maknassy; Medenine; Menzel-Bouzelfa; Menzel-Temime; Nabeul; Sfax-sud; Sidi Bouzid; Siliana; Sousse; Tataouine; Tozeur; Zaghouan | 20/26 | 26.000/104.000 |
| **North-West** *TN2035_B_North-West* | Bizerte; Kasserine; Siliana | 3/4 | 4.000/16.000 |
| **RES-oriented** *TN2035_B_RES-oriented* | Bizerte; Gabes; Gafsa; Kairouan; Kasserine; Kebili; Medenine; Menzel-Bouzelfa; Menzel-Temime; Sidi Bouzid; Tataouine; Tozeur; Zaghouan | 13/18 | 18.000/72.000 |

**Note:** Candidates outside each eligibility domain are disabled. Enabled candidates retain the reference four-hour duration, round-trip efficiency, BESS cost assumption, and individual 1000 MW investment bound. Candidate ceilings are aggregate pre-optimisation limits and are distinct from model-selected BESS capacity. *TN2035_B_REF* is the common manuscript comparator, whereas *TN2035_B_Site_All* is the unrestricted S7 control. Because some nodes host both solar- and wind-oriented BESS candidates, the number of candidate options can exceed the number of eligible nodes; in the North-West domain, Kasserine retains two candidates. Node names follow the domestic network dictionary; external nodes are excluded. RES = renewable energy sources.

### *Appendix A.2. S8 Renewable-Profile Transformations*

The S8 family modifies the hourly PV and wind available-power ceilings while retaining installed renewable capacities, nodal allocations, demand, thermal generation data, network topology, interconnection assumptions, costs, and BESS parameters. Nine cases apply deterministic annual multipliers, while the synthetic 168 h low-VRE stress applies PV $\times$ 0.70 and wind $\times$ 0.50 only during model hours 4674–4841, with the reference profiles retained elsewhere. SolarSurplus applies an annual PV $\times$ 1.10 scaling. Table A2a defines the transformations, temporal scope, and spatial coverage, while Table A2b specifies the bounding rules applied to the transformed profiles.

**Table A2.** (**a**) Deterministic available-power transformations for the S8 VRE-profile sensitivity; (**b**) upper-bound treatment for the S8 VRE-profile transformations.

**(a)**

| Case/Manuscript Label | Available-Power Transformation | Temporal Scope | Spatial Scope |
|---|---|---|---|
| *TN2035_B_REF* **Reference profiles** | PV unchanged; wind unchanged | Full chronology | 28 PV + 15 wind units/21 nodes |
| *TN2035_B_REProfile_Dunkelflaute* **Synthetic 168 h low-VRE stress** | PV $\times$ 0.70; wind $\times$ 0.50 during the stress window; unchanged otherwise | Hours 4674–4841; 14 July 17:00–21 July 16:00 | 28 PV + 15 wind units/21 nodes |
| *TN2035_B_REProfile_PVHigh5* **PV availability +5%** | PV $\times$ 1.05; wind unchanged | Full chronology | 28 PV units/17 nodes |
| *TN2035_B_REProfile_PVLow5* **PV availability −5%** | PV $\times$ 0.95; wind unchanged | Full chronology | 28 PV units/17 nodes |
| *TN2035_B_REProfile_PVLow10* **PV availability −10%** | PV $\times$ 0.90; wind unchanged | Full chronology | 28 PV units/17 nodes |
| *TN2035_B_REProfile_SolarSurplus* **Annual solar-surplus scaling** | PV $\times$ 1.10; wind unchanged | Full chronology | 28 PV units/17 nodes |
| *TN2035_B_REProfile_VREHigh5* **Combined VRE availability +5%** | PV $\times$ 1.05; wind $\times$ 1.05 | Full chronology | 28 PV + 15 wind units/21 nodes |
| *TN2035_B_REProfile_VRELow10* **Combined VRE availability −10%** | PV $\times$ 0.90; wind $\times$ 0.90 | Full chronology | 28 PV + 15 wind units/21 nodes |

**Table A2.** *Cont.*

| | | | |
|---|---|---|---|
| *TN2035_B_REProfile_WindHigh10* **Wind availability +10%** | PV unchanged; wind × 1.10 | Full chronology | 15 wind units/10 nodes |
| *TN2035_B_REProfile_WindLow10* **Wind availability −10%** | PV unchanged; wind × 0.90 | Full chronology | 15 wind units/10 nodes |
| *TN2035_B_REProfile_WindLow20* **Wind availability −20%** | PV unchanged; wind × 0.80 | Full chronology | 15 wind units/10 nodes |

**(b) Upper-bound treatment for the S8 VRE-profile transformations.**

| Technical Case ID | Bounding Treatment | Generator-Hours Capped at Static *MaximumPower* |
|---|---|---|
| *TN2035_B_REF* | Reference profiles retained without transformation | — |
| *TN2035_B_REProfile_Dunkelflaute* | Standard S8 bound within the 168 h stress window; reference profiles retained elsewhere | 0 |
| *TN2035_B_REProfile_PVHigh5* | Standard S8 bound | 0 |
| *TN2035_B_REProfile_PVLow5* | Standard S8 bound | 0 |
| *TN2035_B_REProfile_PVLow10* | Standard S8 bound | 0 |
| *TN2035_B_REProfile_SolarSurplus* | Standard S8 bound | 0 |
| *TN2035_B_REProfile_VREHigh5* | Standard S8 bound | 1616 |
| *TN2035_B_REProfile_VRELow10* | Standard S8 bound | 593 |
| *TN2035_B_REProfile_WindHigh10* | Standard S8 bound | 2128 |
| *TN2035_B_REProfile_WindLow10* | Standard S8 bound | 593 |
| *TN2035_B_REProfile_WindLow20* | Standard S8 bound | 0 |

**Note:** Transformations are applied to the hourly available-power ceilings specified by *VariableMaxGeneration*. "Full chronology" denotes all 8736 model hours. Installed renewable capacities and nodal allocations remain unchanged. The synthetic 168 h low-VRE stress affects only model hours 4674–4841; reference profiles are retained outside this interval. Model-calendar dates locate these hours within the represented 52-week chronology rather than an 8760 h civil year. Bounding rules for transformed values are reported separately in Table A2b. Technical case IDs are retained as model identifiers; *TN2035_B_REProfile_Dunkelflaute* is referred to in the manuscript as Synthetic 168 h low-VRE stress. For transformed S8 profiles, the standard bounding rule caps targeted values at the corresponding static generator *MaximumPower*; no lower clipping is applied, and untargeted technologies remain unchanged. The untransformed *TN2035_B_REF* case retains its original hourly *VariableMaxGeneration* ceilings, including positive values above static *MaximumPower*, because *VariableMaxGeneration* defines the applicable hourly bound in openTEPES when specified. Missing *VariableMaxGeneration* entries use the static-limit fallback described in Section 2.5. For the synthetic 168 h low-VRE stress, reference profiles are retained outside model hours 4674–4841. This stress defines a deterministic scenario boundary rather than an event-probability or return-period estimate.

### *Appendix A.3. Data Sources and Model Representation*

**Table A3.** Data sources, numerical representation and model treatment.

| Data Component | Numerical Representation | Source or Modelling Basis | Model Treatment |
|---|---|---|---|
| **2024 demand chronology and nodal allocation** | STEG-derived reference chronology processed into an 8736 × 47 hourly nodal demand matrix | STEG Annual Report 2024 [30]; expert-informed spatial aggregation developed by the authors | Forty-seven domestic demand nodes represent Tunisia's principal regions and demand centres; STEG-reported node-level information is mapped to *oT_Data_Demand*; chronology is harmonised with the 8736 h model horizon |
| **2030 and 2035 demand projections** | 29.500666 and 33.300 TWh; 8736 × 47 hourly nodal matrices | 2024 STEG-derived reference demand matrix; Tunisia 2035 energy-strategy framework [13] | Annual demand is scaled to each horizon while preserving the 2024-derived temporal profile and nodal shares; the matched 2035 cases use the same demand matrix |
| **Generation fleet, renewable capacity and siting** | 37 gas-fired, 7 hydropower, 28 solar and 15 wind units in 2035; exogenous capacities and nodal allocations | National planning assumptions [13]; project-specific processed generation dataset | Technology, capacity, nodal assignment, output bounds and static availability are fixed within each model horizon |

**Table A3.** *Cont.*

| Data Component | Numerical Representation | Source or Modelling Basis | Model Treatment |
|---|---|---|---|
| **Reference PV/wind chronology** | 43 generator-level VRE series; 8736 hourly available-power ceilings (MW) | Project-specific processed renewable-availability profiles | *VariableMaxGeneration* defines hourly availability; central cases use the same reference profiles, while S8 applies prescribed deterministic transformations |
| **Network topology and circuit parameters** | 87/96/101 circuits in 2024/2030/2035; voltage, reactance, loss factor, TTC and security factor | Project-specific processed network dataset informed by national system documentation; ELMED documentation [14] | Horizon-specific topology is exogenous; active-power routing uses the DC representation; effective transfer capacity = TTC × security factor |
| **ELMED and Algerian exchange cases** | 2024 calibrated Algerian imports; prospective 0/300/600 MW screens; 600 MW ELMED option | STEG [30]; World Bank ELMED documentation [14]; study-defined sensitivity assumptions | The 2024 baseline includes calibrated Algerian imports; prospective central cases disable imports; S4 tests controlled Algerian/ELMED availability |
| **Economic and direct-emission inputs** | Fuel and variable operation and maintenance (O&M) costs; direct-emission rates; $CO_2$ price = 25 EUR $tCO_2^{-1}$; BESS cost assumption = 200 kEUR $MW^{-1}$; fixed charge rate = 0.08 $yr^{-1}$ | Project-specific model inputs and study assumptions | Applied consistently within the model cost boundary; direct emissions cover domestic operation only |
| **Assumed VoLL/ENS penalty** | Central value: 10,000 EUR $MWh^{-1}$; S2 range: 2000–50,000 EUR $MWh^{-1}$ | Exogenous study assumption; methodological context [29] | Implemented through *ENSCost*; comparisons requiring a common cost basis use a consistent VoLL assumption |
| **BESS technical design and candidate domain** | 27 candidates at 21 unique nodes; 1000 MW per candidate; 4 h central duration; 90% round-trip efficiency | Study-defined technical assumptions; project-specific candidate-node mappings | Power and energy are coupled through imposed duration; S6 varies duration and S7 candidate eligibility |
| **Software and optimisation configuration** | openTEPES 4.18.16; Gurobi Optimizer 13.0.2; 8736 sequential one-hour load levels | openTEPES [10]; Gurobi Optimizer | Continuous linear optimisation with one period, one scenario and one stage; losses enabled; binary unit commitment, switching and endogenous line investment disabled |

**Note:** Public reports and strategic documents provide system-level context and selected reference values, while hourly nodal, generator-level, and circuit-level inputs are represented through project-specific processed datasets. BESS = battery energy storage system; ENS = energy not served; TTC = total transfer capacity; VRE = variable renewable energy; VoLL = value of lost load.

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