



Beyond levelized cost: Risk-informed full-system screening of Iran's electricity pathways—Iran Hormoz nuclear case study

Abouzar Kiyani ^{a,*}, Parviz Parvin ^a, Naser Mansour Sharifloo ^b, Ali Bahrami Samani ^c

^a Department of Energy Engineering and Physics, Amirkabir University of Technology (Tehran Polytechnic), P.O. Box 15875-4413, Tehran, Iran

^b Department of Mechanical & Energy, Islamic Azad University, Central Tehran Branch, Tehran, Iran

^c Nuclear Science and Technology Research Institute (NSTRI), P.O. Box: 14155-1339, Tehran, Iran

Keywords

Levelized cost of electricity
Full-system screening
Equivalent-service comparison
Nuclear project economics
Bankability
Project risk

Article Info

DOI: [10.22060/aest.2026.26511.1014](https://doi.org/10.22060/aest.2026.26511.1014)

Received date 13 August 2026

Revised date 8 September 2026

Accepted date 16 September 2026

* Corresponding author:

aboo.kiyani@aut.ac.ir

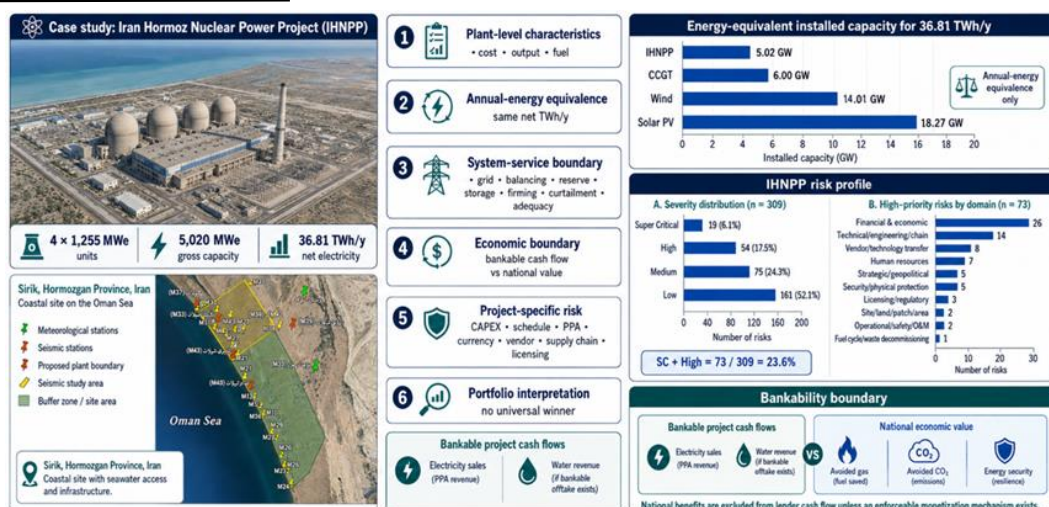
Abstract

Levelized cost of electricity (LCOE) is useful for initial technology screening, but it does not fully represent the cost or value of delivering comparable electricity-system services. This study develops a risk-informed full-system screening framework for Iranian electricity pathways and applies it to the four-unit Iran Hormoz Nuclear Power Project (IHNPP). The framework distinguishes annual-energy equivalence from system-service equivalence, separates bankable project cash flow from wider national economic value, and incorporates project-specific delivery risk without claiming a chronological power-system optimization.

IHNPP comprises four nominal 1,255-MWe units with 5,020 MWe of gross capacity. Under a 93% production factor and 10% internal electricity consumption, annual generation is 40.90 TWh gross and 36.81 TWh net. Matching this net annual output requires approximately 6.00 GW of CCGT at a 70% net capacity factor, 14.01 GW of onshore wind at 30%, or 18.27 GW of solar PV at 23%. Sensitivity over an IHNPP production-factor range of 85–95% changes net generation from 33.64 to 37.60 TWh/y. The economic screening adopts a total CAPEX of USD 25.0 billion, equivalent to approximately USD 4,980/kW gross, with annual OPEX and overhaul expenditure of USD 441.70 million. At USD 0.05/kWh, annual electricity-sale revenue is approximately USD 1.84 billion. Deterministic sensitivity tests examine CAPEX, tariff, production factor, financing conditions, and construction delay. The project register contains 309 risks, of which 73 (23.6%) are Super Critical or High; financial and economic risks account for 35.6% of this priority subset.

The results indicate that technology ranking cannot be inferred from LCOE or annual energy alone. For IHNPP, economic performance remains strongly conditioned by financing, project delivery, contractual arrangements, and grid integration.

Graphical Abstract



Copyrights for this article are retained by the author(s) with publishing rights granted to Amirkabir University Press. The content of this article is subject to the terms and conditions of the Creative Commons Attribution 4.0 International (CC-BY-NC 4.0) License. For more information, please visit: <https://creativecommons.org/licenses/by-nc/4.0/>

Journal homepage: <https://aest.aut.ac.ir/>

E-ISSN: 3115-9117



1. Introduction

Electricity planning cannot be reduced to selecting the generation technology with the lowest apparent cost per megawatt-hour. Technologies differ in capital intensity, construction lead time, financing exposure, utilization, fuel dependence, operational profile, and the services they provide to the power system. These differences matter because electricity systems must preserve affordability, adequacy, flexibility, security of supply, and resilience while accommodating new generating capacity. LCOE remains a useful plant-level screening metric, but its interpretation becomes increasingly limited when technologies provide materially different system services or face substantially different financing structures [1]. The IEA–NEA generating-cost framework similarly shows that discount rate and financing assumptions can materially influence the economics of capital-intensive generation.

A substantial literature has moved beyond plant-boundary cost comparisons. Ueckerdt et al. introduced the system-LCOE concept to separate generation cost from profile, balancing, and grid-related effects [2]. Hirth showed that the market value of variable renewable generation changes with penetration because production is temporally correlated and therefore does not retain a constant marginal system value [3]. More recent OECD Nuclear Energy Agency work similarly treats low-carbon system cost as an interaction among generation, networks, flexibility, storage, and security-of-supply requirements [4]. The implication is not that variable renewable energy is inherently expensive, but that its value and integration cost depend on the characteristics of the surrounding electricity system.

The same system-level discipline must be applied to firm generation. High annual utilization does not make a nuclear plant integration-free: large units affect transmission planning, reserve requirements, outage management, and the treatment of credible single-unit contingencies. Conversely, gas-fired generation provides dispatchable and flexible output but remains exposed to continuous fuel supply, fuel opportunity cost, and direct combustion emissions. A defensible comparison must therefore consider the services each technology provides and the costs and risks transferred to the wider system, rather than comparing nameplate capacity alone [4].

Studies of deeply decarbonized power systems further support a portfolio-based interpretation. Sepulveda et al. showed that firm low-carbon resources can reduce system costs by complementing variable renewable generation under stringent decarbonization constraints [5]. Kan et al., examining Sweden, found that the economic role of new nuclear capacity depends strongly on the characteristics of the surrounding system and the alternatives available [6]. These findings are complementary rather than contradictory: both indicate that technology value is system-specific rather than intrinsic.

Iran-specific studies have addressed several parts of this broader problem. Ghorbani et al. examined pathways toward a highly renewable Iranian energy system and highlighted the role of storage [7]. Aryanpur et al. investigated how energy-subsidy reform could influence the long-term development of the Iranian power sector [8]. Saedi and Ahmadi assessed life-cycle implications of changes in Iran's electricity portfolio [9], while Nasouri and Delgarm examined the contribution of nuclear generation to sustainable energy development in Iran [10]. Taken together, these studies address renewable deployment, fuel pricing, life-cycle effects, and nuclear energy, but they do not integrate annual-energy equivalence, system-boundary screening, project bankability, and project-specific delivery risk within a single large nuclear programme. Related work by members of the present author group has examined SMR deployment in Iran from comparative and feasibility-to-deployment perspectives [11, 12]. The present study addresses a different scale and decision problem: a large four-unit nuclear programme assessed through annual-energy equivalence, bankability, system-boundary considerations, and project-specific delivery risk.



IHNPP provides the project-specific nuclear case for this study. The current project basis comprises four nominal 1,255-MWe units, corresponding to 5,020 MWe of total gross capacity. Project feasibility, financial, and risk-management documents provide the technical and economic inputs used later in the screening analysis. Because the project remains under development, these inputs are treated as the current planning basis rather than final EPC or operating data.

The case also highlights an important distinction between project bankability and national economic value. Electricity sales can generate contractual project cash flow when supported by an enforceable and creditworthy offtake arrangement. By contrast, avoided natural-gas consumption, avoided emissions, and broader energy-security benefits primarily accrue at the national level unless an explicit mechanism transfers their value to the project company. Treating these categories separately prevents wider economic benefits from being presented as lender-available cash flow.

Project-specific delivery risk provides the fourth analytical layer. The controlled IHNPP risk register captures financial, contractual, technical, supply-chain, licensing, organizational, and external-hazard exposures associated with a multi-unit nuclear programme. In this study, those risks are used to interpret the conditions under which deterministic economic assumptions may or may not be realized. The risk layer is therefore informative for prioritization and economic interpretation, but it is not treated as a probabilistic financial model.

The contribution of this study is fourfold. First, it distinguishes equal installed capacity, equal annual electricity, and equivalent system service. Second, it defines a broader system boundary in which grid, balancing, storage, firming, curtailment, reserve, and adequacy requirements remain visible without assigning unsupported numerical adders. Third, it separates bankable project cash flow from wider national economic value. Fourth, it uses a project-specific nuclear risk register to interpret financing, contractual, execution, supply-chain, and programme-level delivery conditions without converting ordinal risk scores into probability distributions or monetary losses.

Accordingly, the objective is not to rank technologies through a complete Iranian power-system optimization. The study instead asks what can be established from a transparent screening exercise that combines annual-energy equivalence, system-service boundaries, project bankability, life-cycle considerations, energy security, and project-specific delivery risk. The resulting framework is intended to support disciplined comparison while keeping assumptions, data limitations, and unresolved system-level requirements explicit.

2. Materials and Methods

The methodology is structured as a risk-informed screening analysis that progressively expands the comparison from plant-level electricity output to system-service, economic, and project-delivery boundaries. Quantitative results are reported only where the required inputs are available from controlled project documents, published evidence, or explicitly defined screening assumptions. System adequacy, grid integration, life-cycle effects, and project-delivery risk are incorporated at the level supported by the available evidence rather than being represented through unsupported numerical optimization.

Four generation pathways are considered: IHNPP nuclear generation, natural-gas combined-cycle generation (CCGT), utility-scale solar PV, and onshore wind. The quantitative comparison begins with a common net annual-electricity target and then extends to economic, system-boundary, and project-risk interpretation. Portfolio combinations are discussed only where supported conceptually; no numerical portfolio optimization is performed.



2.1. Equivalent-Service and System-Boundary Framework

Three levels of comparison are distinguished as follows:

Installed-capacity equivalence compares nameplate capacity alone. It is insufficient when technologies differ substantially in annual utilization and internal electricity consumption.

Annual-energy equivalence requires each alternative pathway to deliver the same annual net electricity to the grid as the IHNPP reference case. This is the highest level of equivalence quantified directly in the present study.

System-service equivalence would additionally require comparable contributions to demand adequacy, dependable capacity, reserve, flexibility, and temporal balancing. Establishing that equivalence requires chronological system data and is therefore treated here as an explicit analytical boundary rather than a calculated result.

To maintain a consistent functional boundary, all energy-equivalence calculations are normalized to net electricity delivered at the grid interface. IHNPP is retained at its documented gross nameplate capacity of 5,020 MWe, and its annual net export is calculated explicitly after accounting for internal electricity consumption. For CCGT, solar PV, and onshore wind, the capacity factors used in the screening are defined as effective net-to-grid utilization factors; plant auxiliary use and balance-of-plant losses are therefore treated as embedded in the adopted scenario values. The comparison consequently uses a common net annual-electricity target rather than mixing gross generation with net grid delivery.

For IHNPP, annual net electricity is calculated as

$$E_{\text{net}} = P_{\text{gross}} \times 8760 \times \text{PF} \times (1 - f_{\text{aux}}) \quad (1)$$

Where E_{net} is annual net electricity delivered to the grid, P_{gross} is gross installed electrical capacity, PF is the adopted annual production factor, and f_{aux} is the fraction of gross electricity consumed internally by the plant.

For IHNPP, the 93% production factor is retained as the project reference assumption rather than interpreted as measured operating performance. To test the dependence of the screening results on this assumption, additional cases of 85%, 90%, and 95% are evaluated while keeping the 10% internal-consumption assumption unchanged.

For an alternative pathway j , the installed capacity required to produce the same annual net electricity is

$$P_{j,\text{eq}} = \frac{E_{\text{IHNPP},\text{net}}}{8.76 \text{ CF}_{j,\text{net}}} \quad (2)$$

Where $P_{j,\text{eq}}$ is the energy-equivalent installed capacity in GW, $E_{\text{IHNPP},\text{net}}$ is the IHNPP reference net generation in TWh/y and $\text{CF}_{j,\text{net}}$ is the effective net-to-grid capacity factor adopted for pathway j .

The alternative-pathway capacity factors are treated as screening assumptions rather than national fleet averages or site-specific forecasts. For CCGT, net capacity factors of 60%, 70%, and 80% are examined, with 70% used as the central dispatch-utilization case. Because CCGT utilization is strongly influenced by dispatch, fuel availability, maintenance, and system demand, this range is used as a scenario envelope rather than an empirical Iranian fleet estimate.

For utility-scale solar PV, net capacity factors of 20%, 23%, and 25% are examined. The central value of 23% is consistent with the upper end of published Iran-specific PV assessments; Edalati et al. reported modeled capacity factors ranging from 12% in Ramsar to 23.13% in Kerman [13].

For onshore wind, the revised screening range is 25%, 30%, and 35%, with 30% used as the central case. Iran-specific wind-resource assessments show substantial site- and turbine-dependent variation, supporting the use of a range rather than a single national value [14].



These values are used only to test annual-energy equivalence. They should not be interpreted as forecasts for specific projects, nor as evidence of system-service equivalence.

A complete full-system comparison can be represented conceptually as

$$FSC = C_{\text{gen}} + C_{\text{grid}} + C_{\text{bal}} + C_{\text{storage}} + C_{\text{firm}} + C_{\text{curt}} + C_{\text{adequacy}} \quad (3)$$

Where the terms represent generation, grid, balancing, storage, firming, curtailment, and adequacy-related costs, respectively. This accounting structure follows the system-cost literature [2–4]. Equation (3) is used as a structured accounting and screening boundary rather than as a claim that a complete numerical full-system cost has been calculated. Accordingly, no universal numerical adders are assigned to grid reinforcement, balancing, storage, firming, curtailment, or adequacy in the absence of a chronological system model.

No universal renewable-integration surcharge is imposed. The requirements for storage, balancing, transmission, curtailment management, and firming depend on renewable-resource profiles, penetration level, network topology, interconnection, geographical diversity, and the flexibility already available in the system. The same principle is applied to nuclear generation: high annual utilization does not eliminate transmission, reserve, outage-management, or large-unit contingency requirements. **Fig. 1** summarizes the analytical sequence used in the screening framework.



Fig. 1. Integrated Risk-Informed Full-System Screening Framework.

2.2. IHNPP Project Data and Economic Boundary

Project-specific inputs are drawn from the current IHNPP feasibility, financial, and risk-management documentation. These sources provide the project configuration, production assumptions, operating expenditure, working-capital requirement, electricity-tariff scenario, and risk-register data used in the screening. Where project documentation does not provide the information required for a comparison, the analysis uses either published external evidence or an explicitly identified engineering scenario assumption. No screening assumption is treated as measured IHNPP operating data.



To preserve data traceability, each numerical input is classified as project data, an authors' calculation, published external data, or a screening assumption. The distinction is particularly important for the economic analysis. The USD 25.0 billion total CAPEX used in this paper is an adopted study-case value rather than a final EPC contract price or audited financed cost. By contrast, the OPEX, working-capital, tariff, and production-factor, auxiliary-consumption, and risk-register inputs are drawn from the project documentation. **Table 1** summarizes the principal screening inputs and their provenance.

Table 1. Key IHNPP inputs and data provenance.

Parameter	Value used	Data status	Role in analysis
IHNPP units	4	Project data	Reference configuration
Gross capacity per unit	1,255 MWe	Project data	Reference configuration
Total gross capacity	5,020 MWe	Project data	Reference configuration
IHNPP production factor	93%	Project assumption	Base case; 85–95% sensitivity
Internal electricity consumption	10%	Project assumption	Net-generation calculation
Gross annual generation	40.90 TWh/y	Authors' calculation	Derived
Net electricity delivered to grid	36.81 TWh/y	Authors' calculation	Energy-equivalence target
Total CAPEX	USD 25.0 bn	Study-case assumption	Base economic case
CAPEX intensity	USD 4,980/kW gross	Authors' calculation	Descriptive
Annual OPEX + overhaul	USD 441.70 million/y	Project data	Operating-cost screening
Working capital	USD 409.78 million	Project data	Funding requirement
Electricity tariff	USD 0.05/kWh	Project scenario	Base revenue case
Electricity-sale revenue	USD 1.84 billion/y	Authors' calculation	Direct project revenue
CCGT net efficiency	44.7–45.2%	Iran-specific published data [16]	Gas/CO ₂ counterfactual
Natural-gas LHV	36.0 MJ/Nm ³	Engineering screening assumption	Volumetric gas conversion
Natural-gas CO ₂ factor	56.1 kg CO ₂ /GJ	IPCC default [17]	Combustion counterfactual
Project risk register	309 risks	Project data	Risk screening
SC + High risks	73 (23.6%)	Project data/calculation	Priority subset

The project documentation supports the four-unit 5,020-MWe configuration, the 93% reference production-factor assumption, 10% internal electricity consumption, annual OPEX and overhaul expenditure of USD 441.70 million, working capital of USD 409.78 million, and the USD 0.05/kWh electricity-tariff scenario. The USD 25.0 billion CAPEX case is imposed separately as the common investment assumption used in the present revision.

Applying Eq. (1) gives 40.8969 TWh/y of gross electricity and 36.8072 TWh/y of net electricity delivered to the grid. These values are reported as 40.90 and 36.81 TWh/y, respectively. At the adopted USD 25.0 billion CAPEX, the corresponding gross-capacity investment intensity is approximately USD 4,980/kW. At the reference tariff of USD 0.05/kWh, 36.8072 TWh/y of net electricity corresponds to approximately USD 1.84 billion/y of electricity-sale revenue.

A complete NPV, IRR, or DSCR analysis is not reported because the available four-unit dataset does not yet provide a fully auditable financing structure covering debt and equity drawdown, interest during construction, financing fees, taxation, repayment terms, escalation, currency structure, and unit-specific commercial-operation dates. These variables are particularly important for capital-intensive nuclear new build, for which financing structure and risk allocation can materially influence total economic performance [15].

For the CCGT counterfactual, natural-gas use and direct CO₂ emissions are derived from a common thermal-energy basis rather than from independent project factors. Iran-specific published data report average combined-cycle efficiencies of



approximately 44.7% for government-owned plants and 45.2% for privately owned plants [16]. This 44.7–45.2% range is therefore used for the screening calculation.

The corresponding net heat rate is obtained from $HR=3.6/\eta_{CCGT}$, giving approximately 7.96–8.05 MJ of fuel input per kWh of net electricity. For volumetric conversion only, a natural-gas lower heating value of 36.0 MJ/Nm³ is adopted as an explicit engineering screening assumption because a project-specific gas composition and calorific value were not available in the controlled dataset. Natural-gas consumption is then calculated as $q_{gas}=HR/LHV_{gas}$.

Direct combustion CO₂ emissions are derived from the same thermal input using the IPCC natural-gas emission factor of 56.1 kg CO₂/GJ [17]. The resulting gas-consumption and emission factors are therefore internally consistent and represent a CCGT operational counterfactual rather than a life-cycle comparison.

Monetary valuation of displaced gas or avoided CO₂ is not included in the revised base-case project cash flow. These quantities are retained as physical national-economic indicators unless a transparent and enforceable monetization mechanism is specified.

Desalinated-water co-production is excluded from the quantitative economic case. A defensible valuation would require a defined desalination technology and configuration, explicit electricity and/or thermal-energy demand, dedicated CAPEX and OPEX, availability assumptions, product-water specifications, and a bankable long-term offtake agreement. These inputs are not sufficiently defined in the present dataset; desalination is therefore retained only as a potential future project option.

Economic robustness is evaluated through deterministic one-at-a-time stress tests rather than through a probabilistic financial model. Total CAPEX is varied from USD 20 to 30 billion around the USD 25 billion reference case, and the electricity tariff is varied from USD 0.04 to 0.06/kWh around the USD 0.05/kWh reference value. The IHNPP production factor is examined separately over 85–95%, as defined in Section 2.1. These ranges are transparent screening intervals and are not presented as statistical confidence bounds.

Financing and delay sensitivity uses the temporal shape of the available IHNPP construction cash-flow schedule rather than converting its euro-denominated amounts directly into the USD 25 billion study case. Annual construction outlays are first expressed as shares of the reported 2024–2037 construction profile and are then rescaled so that their total equals USD 25 billion. Annual financing-rate proxies of 5%, 7%, and 10% are used as low, central, and high stress cases rather than as project WACC estimates or contractual borrowing rates. Construction delay is represented as an additional financing-carry period of 0, 2, or 4 years after the base construction-expenditure horizon while holding the normalized expenditure profile unchanged. The resulting quantities are therefore financing stress-test indicators, not forecasts of final financed project cost. The economic boundary separates direct project cash flow from wider national economic effects. Electricity-sale revenue is treated as bankable only to the extent that it is supported by an enforceable PPA, a creditworthy offtaker, and a credible payment-security mechanism. Physical gas displacement, avoided combustion emissions, and broader energy-security effects are reported separately and are not added to lender-available project cash flow. This distinction is maintained throughout the Results and Conclusions.

2.3. Project-Risk and Life-Cycle Boundaries

The project-risk analysis is based on the current controlled IHNPP register, which contains 309 identified risks across 12 Level-1 domains. The present study does not independently generate or rescore these risks. Instead, the Severity, Occurrence, and Detection scores recorded in the controlled register are treated as source data and are subsequently audited, aggregated, and interpreted at risk-class and domain levels. Risk priority is expressed as



$$RPN_i = S_i \times O_i \times D_i \quad (4)$$

Where S_i , O_i , and D_i are the ordinal Severity, Occurrence, and Detection scores assigned to risk i in the source register. Severity represents the magnitude of potential consequence, Occurrence represents the assessed likelihood or frequency within the project horizon, and Detection represents the difficulty of identifying the risk early enough to intervene before its consequence materializes:

The three factors are scored on ordinal project-management scales rather than interpreted as physical probabilities or continuous statistical variables. Their purpose is to support internal prioritization across heterogeneous technical, financial, contractual, regulatory, safety, security, and programme risks. Consequently, multiplication of the three scores produces a ranking index rather than a probabilistic measure of project failure.

The controlled project methodology classifies risks as follows:

- *Low (L)*: $RPN \leq 60$ — controlled acceptance with monitoring proportionate to the nature of the risk;
- *Medium (M)*: $61 \leq RPN \leq 90$ — management control, resource allocation, and periodic monitoring;
- *High (H)*: $91 \leq RPN \leq 140$ — an approved mitigation plan, identified risk ownership, and formal treatment of residual exposure are required; and
- *Super Critical (SC)*: $RPN \geq 141$ — immediate management attention is required, and progression through relevant project stage gates should not proceed without appropriate risk control.

The present study did not reconstruct the upstream expert-elicitation process used to establish the individual S, O, and D scores. The controlled documentation available to the authors specifies the scoring dimensions and RPN classification rules but does not provide sufficient information to reproduce the number and disciplinary composition of assessors, the number of assessment rounds, or the consensus procedure used when the register was originally compiled. No undocumented elicitation method is therefore inferred. This limitation concerns the provenance of the original scores; the aggregation, classification, and domain-level calculations performed in the present study remain reproducible from the controlled register.

RPN is therefore used strictly as a semi-quantitative prioritization metric. It is not interpreted as the probability of project failure, accident frequency, probability of default, expected monetary loss, or a probabilistic nuclear-safety metric. The broader risk-management treatment follows ISO 31000 [18], while the use and limitations of RPN-type prioritization are consistent with FMEA/FMECA practice described in IEC 60812 [19].

Nuclear-safety, radiological, physical-security, and regulatory significance are not subordinated to the numerical RPN ranking. A high-consequence event can receive a moderate RPN when its occurrence or detection score is low. Accordingly, deterministic safety requirements, defence-in-depth, regulatory acceptance criteria, and engineering judgement provide an overriding decision layer where required.

The risk layer is semi-quantitative for prioritization but qualitative with respect to economic transmission. Priority risks are interpreted through the project variables that they can affect. PPA and payment-security risks influence revenue certainty and bankability; construction and licensing delays affect commercial-operation dates and financing carry; CAPEX escalation increases funding requirements; currency restrictions affect imported equipment and debt-service exposure; vendor and supply-chain disruptions can affect both cost and schedule; and grid constraints can affect electricity delivered to the offtaker. The deterministic sensitivity tests defined in Section 2.2 examine selected economic transmission channels independently of the RPN ranking.



No probability distribution, monetary loss, financing premium, or Monte Carlo input is inferred from RPN. Where quantitative stress testing is performed, the relevant economic variable is varied directly using an independently defined scenario range rather than a probability derived from the ordinal risk score.

The multi-unit configuration introduces a further distinction between unit-specific and site- or programme-level exposure. Four units at one site may share construction resources, grid infrastructure, cooling-water systems, vendor dependencies, organizational arrangements, regulatory interfaces, and exposure to external hazards. Multi-unit nuclear risk therefore cannot be represented by simple replication of an independent single-unit risk model. IAEA guidance similarly emphasizes the need to account for inter-unit and site-level dependencies in multi-unit probabilistic safety assessment [20]. The present study recognizes these dependencies qualitatively but does not perform a multi-unit PSA.

Life-cycle considerations are retained as a supporting decision boundary rather than developed as a new comparative LCA. ISO 14040 and ISO 14044 provide the methodological basis for consistent goal, scope, inventory, impact assessment, and interpretation [21, 22], while the UNECE assessment provides a harmonized reference for electricity-generation life cycles [23]. Because a consistent Iran-specific inventory is not available for all four pathways, the study does not generate new comparative values for life-cycle greenhouse-gas intensity, land use, water consumption, material requirements, or waste.

3. Results and Discussion

3.1. IHNPP Reference Case and Energy-Equivalent Pathways

The IHNPP reference configuration comprises four nominal 1,255-MWe units with a total gross nameplate capacity of 5,020 MWe. Under the project reference production-factor assumption of 93%, gross annual generation is 40.90 TWh. After applying the 10% internal-consumption assumption, the corresponding net electricity delivered to the grid is 36.81 TWh/y. This net quantity is used consistently as the annual-energy target for all alternative pathways.

The alternative pathways are sized against this common net annual-electricity target using **Eq. (2)**. **Table 2** reports both the technology-specific screening ranges and the sensitivity of the comparison to the assumed IHNPP production factor.

Table 2. Energy-equivalent capacity screening and sensitivity to the IHNPP production-factor assumption.

Panel A. Energy-equivalent capacity at the 93% IHNPP reference production factor.		
Pathway	Screening utilization assumption	Required installed capacity (GW)
IHNPP reference	93% production factor; 10% internal consumption	5.02 GW gross
CCGT	60% net capacity factor	7.00
CCGT — central case	70% net capacity factor	6.00
CCGT	80% net capacity factor	5.25
Solar PV	20% net capacity factor	21.01
Solar PV — central case	23% net capacity factor	18.27
Solar PV	25% net capacity factor	16.81
Onshore wind	25% net capacity factor	16.81
Onshore wind — central case	30% net capacity factor	14.01
Onshore wind	35% net capacity factor	12.00

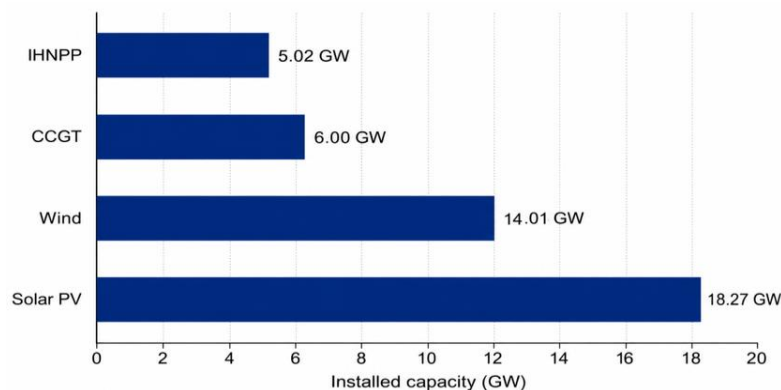
**Panel B.** Sensitivity to the IHNPP production-factor assumption.

IHNPP production factor	IHNPP net generation (TWh/y)	CCGT @ 70% (GW)	Wind @ 30% (GW)	Solar PV @ 23% (GW)
85%	33.64	5.49	12.80	16.70
90%	35.62	5.81	13.55	17.68
93% reference	36.81	6.00	14.01	18.27
95%	37.60	6.13	14.31	18.66

Note: The alternative-technology capacity factors are defined as effective net-to-grid screening values, as specified in Section 2.1. IHNPP retains its documented 5.020-GWe gross nameplate capacity, while its net annual electricity explicitly accounts for the 10% internal-consumption assumption. The reported capacities establish annual-energy equivalence only; they do not include chronological adequacy, storage, firming, curtailment, reserve, or incremental network requirements. The solar-PV and onshore-wind screening ranges are informed by Iran-specific studies [13, 14].

The sensitivity results show the expected near-linear dependence of annual-energy equivalence on the assumed IHNPP production factor. Reducing the production factor from the 93% reference case to 85% lowers net annual generation from 36.81 to 33.64 TWh/y; under the central alternative assumptions, the corresponding capacities decrease to 5.49 GW for CCGT, 12.80 GW for onshore wind, and 16.70 GW for solar PV. At a 95% production factor, IHNPP net generation increases to 37.60 TWh/y, corresponding to 6.13 GW of CCGT, 14.31 GW of wind, and 18.66 GW of solar PV.

This sensitivity should not be interpreted as an uncertainty distribution for future IHNPP performance. It simply shows how strongly the energy-equivalence results depend on the production-factor assumption used to define the nuclear reference case. **Fig. 2** presents the central energy-equivalent cases.

**Fig. 2.** Energy-Equivalent Installed Capacity for 36.81 TWh/y.

Under the revised central assumptions, producing 36.81 TWh/y of net electricity requires approximately 6.00 GW of CCGT, 14.01 GW of onshore wind, or 18.27 GW of solar PV. These differences arise from the assumed annual utilization of each pathway and should not be interpreted as proportional differences in capital cost, land requirement, or economic performance. The calculation answers a narrower physical question: how much nameplate capacity is required to deliver the same annual net electricity under the adopted utilization assumptions?

The larger nameplate capacities calculated for wind and solar reflect lower annual utilization, not an intrinsic economic disadvantage. Both technologies are modular and fuel-free in operation, and their projects can be deployed in smaller increments than a large nuclear unit. IHNPP, by contrast, converts a relatively high assumed annual utilization into a smaller nameplate requirement for the same annual energy, but does so through large, capital-intensive generating units. CCGT occupies a different position: it can provide dispatchable and flexible generation at relatively high utilization, while remaining dependent on continuous natural-gas supply.



Annual-energy equivalence does not establish equivalence in the timing or reliability of electricity supply. Solar and wind portfolios may deliver the same annual TWh while providing different contributions during peak-demand or low-resource periods. Conversely, the trip or planned outage of a single 1,255-MWe nuclear unit represents a large discrete loss of generation that must be accommodated by the surrounding grid. A system-equivalent comparison would therefore require chronological demand and resource profiles, generator availability, transmission constraints, reserve requirements, flexibility, storage where relevant, and an explicit adequacy criterion.

The result is deliberately limited: equal installed capacity, equal annual electricity, and equivalent system service are three different comparison conditions.

3.2. Project Economics and Bankability

The economic screening adopts USD 25.0 billion as the total CAPEX reference case for the four-unit IHNPP programme. Relative to the documented gross nameplate capacity of 5,020 MWe, this corresponds to approximately USD 4,980/kW. The USD 25.0 billion value is used as a study-case assumption rather than interpreted as a final EPC contract price, an audited construction cost, or a fully financed project cost.

Nuclear construction costs have varied widely across countries, reactor programmes, periods, and institutional settings [24, 25]. The purpose of the USD 25.0 billion case is therefore not to establish a universal benchmark for large nuclear projects, but to provide a transparent investment reference against which the IHNPP screening results and sensitivities can be interpreted.

Annual OPEX and overhaul expenditure is retained at USD 441.70 million/y from the project financial assessment. Relative to the reference net generation of 36.807 TWh/y, this corresponds to approximately USD 12.0/MWh. This value is an operating-cost intensity only; it is not an LCOE because it excludes capital recovery, financing, taxation, fuel-cycle provisions not already embedded in the project estimate, and other lifetime financial components.

The project documentation reports a working-capital requirement of USD 409.78 million. At the reference electricity tariff of USD 0.05/kWh, the base-case net generation of 36.807 TWh/y corresponds to approximately USD 1.84 billion/y of electricity-sale revenue. This quantity represents gross electricity-sale revenue before financing, taxation, and other project-level deductions; its bankability depends on the contractual quality of the PPA, tariff indexation, currency denomination, offtaker creditworthiness, payment guarantees, and collection performance. **Table 3** summarizes the base economic case and the deterministic sensitivity tests.

Table 3. IHNPP economic screening and deterministic sensitivity under the USD 25.0 billion CAPEX reference case.

Panel A. Base economic screening.		
Parameter	Base value	Interpretation
Total CAPEX	USD 25.0 bn	Study-case investment assumption
CAPEX intensity	USD 4,980/kW gross	Derived from 5,020 MWe gross capacity
Annual OPEX + overhaul	USD 441.70 million/y	Project operating expenditure
OPEX intensity	USD 12.0/MWh net	Operating cost only; not LCOE
Working capital	USD 409.78 million	Project funding requirement
Net electricity	36.81 TWh/y	Reference net-to-grid generation
Electricity tariff	USD 0.05/kWh	Project screening scenario
Electricity-sale revenue	USD 1.84 billion/y	Gross revenue; conditional on contractual bankability
CCGT natural-gas counterfactual	8.14–8.23 bcm/y	Physical national-energy indicator
CCGT direct CO ₂ counterfactual	16.45–16.63 MtCO ₂ /y	Direct combustion only; not life-cycle emissions

**Panel B.** Deterministic sensitivity.

Variable	Low case	Reference case	High case	Resulting screening effect
CAPEX	USD 20 bn	USD 25 bn	USD 30 bn	USD 3,984 / 4,980 / 5,976 per kW
Electricity tariff	USD 0.04/kWh	USD 0.05/kWh	USD 0.06/kWh	USD 1.472 / 1.840 / 2.208 bn / y revenue
IHNPP production factor	85%	93%	95%	33.64 / 36.81 / 37.60 TWh/y net
Financing-rate proxy	5%	7%	10%	Capitalized-construction index: 1.46 / 1.70 / 2.14
Additional financing-carry delay at 7%	0 y	+2 y	+4 y	Capitalized-construction index: 1.70 / 1.95 / 2.23

Note: The sensitivity cases are deterministic screening stresses, not statistical confidence intervals. The financing-rate cases are proxies and are not presented as the contractual project WACC or borrowing rate. The capitalized-construction index is the accumulated value of the normalized construction-outlay profile relative to the USD 25.0 billion CAPEX reference (=1.00 before financing carry). It is used only to show sensitivity to timing and financing assumptions and should not be interpreted as a forecast of final financed project cost. The temporal construction profile used for the financing and delay stress tests is based on non-public IHNPP planning data made available to the authors.

The deterministic sensitivity results show that the economic scale of the project is strongly assumption-dependent even before a complete financing model is introduced. Varying total CAPEX from USD 20 to 30 billion changes gross-capacity investment intensity from approximately USD 3,984/kW to USD 5,976/kW, compared with USD 4,980/kW in the reference case. At fixed reference generation, changing the electricity tariff from USD 0.04 to USD 0.06/kWh changes annual electricity-sale revenue from approximately USD 1.472 billion to USD 2.208 billion.

Production-factor sensitivity also affects revenue directly. At the reference tariff of USD 0.05/kWh, reducing the IHNPP production factor from 93% to 85% lowers annual net generation from 36.81 to 33.64 TWh and electricity-sale revenue from approximately USD 1.840 billion to USD 1.682 billion. Increasing the production factor to 95% raises net generation to 37.60 TWh and annual electricity-sale revenue to approximately USD 1.880 billion. These values remain deterministic screening results rather than forecasts of future plant performance.

Financing assumptions have a larger cumulative effect because construction expenditure is distributed over many years. The available non-public IHNPP construction schedule provides annual project outlays over 2024–2037. The annual shares of this schedule were normalized and rescaled to the USD 25.0 billion study CAPEX before the financing stress tests were applied. The resulting capitalized-construction index increases from approximately 1.46 at a 5% financing-rate proxy to 1.70 at 7% and 2.14 at 10%. These rates are screening proxies rather than the project WACC or contractual borrowing rates.

Construction delay compounds this exposure. At the central 7% financing-rate proxy, adding two years of financing carry increases the normalized construction-expenditure index from approximately 1.70 to 1.95, while a four-year extension increases it to approximately 2.23. The calculation isolates financing carry only and does not include delay-induced escalation, contractual claims, productivity losses, redesign, additional owner's costs, or deferred operating revenue. It should therefore be interpreted as a stress indicator rather than a comprehensive delay-cost estimate.

The revised CCGT counterfactual is derived from a common thermal-energy basis. Published Iran-specific data report average combined-cycle efficiencies of approximately 44.7–45.2%. With an explicitly stated natural-gas lower heating value of 36.0 MJ/Nm³, this efficiency range corresponds to approximately 0.221–0.224 Nm³/kWh of net CCGT electricity. Producing 36.81 TWh/y would therefore require approximately 8.14–8.23 billion Nm³/y of natural gas.

Using the same thermal input and the IPCC natural-gas combustion factor [17], the corresponding direct CCGT emission intensity is approximately 0.447–0.452 tCO₂/MWh, giving approximately 16.45–16.63 MtCO₂/y for the 36.81-TWh/y



counterfactual. These values represent direct combustion emissions only and are not presented as comparative life-cycle results.

The physical gas and CO₂ counterfactuals are retained as national-energy and environmental indicators. No monetary value is assigned to them in the revised base case because the relevant gas opportunity value, carbon-pricing mechanism, and contractual monetization pathway are scenario-dependent.

Desalinated-water co-production is not assigned a monetary value in the revised analysis. A defensible project-level valuation would require a specified desalination configuration, energy balance, dedicated CAPEX and OPEX, water-production availability, product specification, and enforceable long-term offtake terms. In the absence of those inputs, desalination is treated only as a potential future option.

The distinction is economically important: a project may create national value without generating an equivalent amount of contractually available cash for debt service. No definitive NPV, IRR, or DSCR is reported in the revised manuscript. A defensible calculation would require a dated and internally consistent four-unit financing model covering debt/equity structure, interest during construction, fees, taxation, repayment terms, currency exposure, unit-specific commissioning dates, and contractual revenue timing. Reporting such indicators without these inputs would add numerical precision without corresponding evidentiary strength.

Taken together, the results show that IHNPP bankability cannot be inferred from CAPEX, annual generation, or tariff in isolation. The USD 25.0 billion reference case is economically meaningful only in combination with the timing of construction outlays, financing conditions, commercial-operation dates, contractual revenue security, and the project risks that can alter those variables. The risk analysis in Section 3.3 is therefore used to interpret these transmission channels rather than to convert RPN scores directly into monetary loss.

3.3. Project-Specific Risk and Delivery Exposure

The controlled IHNPP risk register contains 309 risks across 12 Level-1 domains. Of these, 19 are classified as Super Critical, 54 as High, 75 as Medium, and 161 as Low. The two highest priority classes therefore contain 73 risks, corresponding to 23.6% of the register. The maximum recorded RPN is 224. Mean RPN values are retained only as descriptive indicators of relative concentration across domains and are not interpreted as probabilistic risk measures.

Table 4 summarizes the distribution of risks across the 12 Level-1 domains and identifies where Super Critical and High classifications are concentrated.

The strongest concentration of priority risks occurs in the financial and economic domain, which contains 26 Super Critical or High risks. This represents 35.6% of the 73 priority risks in the full register. Technical, execution, and supply-chain risks contribute a further 14 priority items, while vendor/technology-transfer/localization and strategic/geopolitical risks contribute eight and five, respectively. Together, these four domains account for 53 of the 73 Super Critical or High risks (72.6%).

The highest individual RPN, 224, is associated with the bankability of the power-purchase arrangement, electricity-export conditions, and payment guarantees. This result is especially relevant to the economic screening because it identifies revenue security—not only plant performance—as a leading project-delivery concern.

**Table 4.** IHNPP project-risk distribution and priority concentration by Level-1 domain.

Risk domain	Total	SC	H	M	L	SC+H	Mean RPN *	Max RPN
Strategic/geopolitical/foreign policy	23	2	3	8	10	5	73.1	162
Financial and economic	62	11	15	14	22	26	87	224
Technical/execution/supply chain	47	1	13	8	25	14	62.3	150
Human resources/organizational knowledge	27	1	6	6	14	7	56	147
Security/physical protection/operation	32	1	4	5	22	5	44.9	216
Nuclear safety/accident risks	29	0	0	7	22	0	37.9	90
Vendor/technology transfer/localization	25	2	6	5	12	8	66.2	168
Licensing/regulatory/safety assessment	14	0	3	6	5	3	74.9	120
Social/public acceptance	14	0	0	4	10	0	47.4	84
Site/climate/internal-external hazards	19	1	1	9	8	2	67.6	162
Operation/maintenance/grid/reliability	10	0	2	1	7	2	55.3	108
Fuel cycle/waste/decommissioning	7	0	1	2	4	1	57.1	108
Total	309	19	54	75	161	73	63.6	224

Note: SC = Super Critical; H = High; M = Medium; L = Low. Mean RPN is reported only as a descriptive aggregation of the source register and is not interpreted as probability, expected monetary loss, or nuclear-safety frequency.

The economic relevance of the risk register is interpreted through transmission channels rather than through direct monetization of RPN. PPA and payment-security risks affect the certainty and timing of project revenue. Construction and licensing delays can shift commercial-operation dates and extend financing carry. CAPEX escalation increases the funding requirement, while currency restrictions can affect imported equipment costs and foreign-currency debt exposure. Vendor and supply-chain disruptions may affect both cost and schedule, and grid-interface constraints can limit electricity that can be delivered under the offtake arrangement. These relationships motivate the deterministic sensitivity cases presented in Section 3.2, but the RPN values themselves are not used as probabilities or cost multipliers.

In this sense, the framework is risk-informed rather than risk-monetized: the register identifies which project conditions warrant greater attention, while the economic sensitivity analysis evaluates selected variables independently of the ordinal RPN scores. **Fig. 3** summarizes the priority-class distribution and the concentration of Super Critical and High risks by domain.

The absence of Super Critical or High entries in the aggregated nuclear-safety domain should not be interpreted as evidence of low safety significance. RPN combines ordinal consequence, occurrence, and detection scores; a high-consequence event can therefore receive a moderate aggregate RPN when the other factors are lower. Nuclear-safety significance remains governed by deterministic safety requirements, defence-in-depth, regulatory criteria, and engineering judgement rather than by the numerical project-priority ranking alone.

The four-unit configuration also creates dependencies that are not captured by treating each unit as an independent project. Construction resources, grid connections, cooling infrastructure, vendor arrangements, licensing interfaces, organizational capacity, and exposure to some external hazards may be shared across units. These common or programme-level dependencies can allow a single disruption to affect more than one unit or to propagate through the construction sequence. IAEA multi-unit PSA guidance similarly emphasizes the need to recognize inter-unit and site-level dependencies [20]. The present analysis applies this principle qualitatively and does not convert the project register into a multi-unit PSA.

The risk profile changes how the USD 25.0 billion reference case should be interpreted. The relevant economic question is not only whether the completed plant could generate 36.81 TWh/y, but whether the programme can reach commercial



operation under financing, contractual, licensing, currency, vendor, supply-chain, and grid conditions consistent with the assumed investment case. The concentration of priority risks in financial, economic, execution, and supply-chain domains therefore supports treating project delivery as an integral part of the economic interpretation rather than as an external consideration.

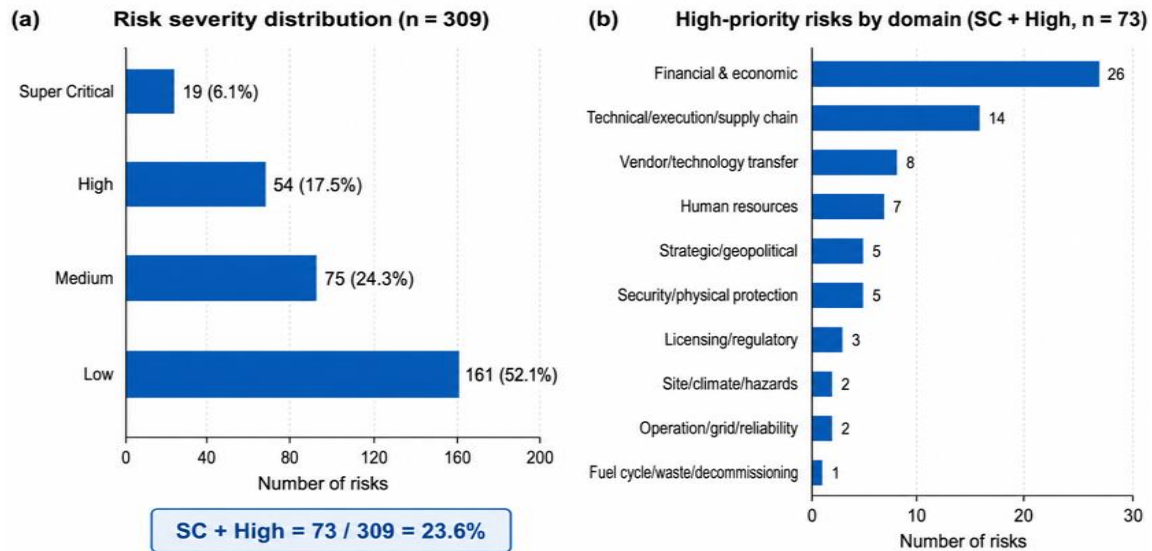


Fig. 3. IHNPP project-risk profile. Panel (a) shows the RPN priority-class distribution for all 309 risks; Panel (b) shows the domain distribution of the 73 risks classified as Super Critical or High. RPN is used as a semi-quantitative project-management prioritization index and is not interpreted as a probability, expected monetary loss, or nuclear-safety frequency.

3.4. Full-System Interpretation

The energy-equivalent results establish a common annual-output reference, but they do not produce a full-system cost ranking. Equal annual electricity is only one dimension of system service.

The larger nameplate capacities calculated for wind and solar should not be interpreted as direct economic penalties. Variable renewable technologies are modular, require no continuous fuel input during operation, and can be deployed in increments smaller than a large nuclear unit. Their system value nevertheless depends on the correlation between resource availability and demand, geographical diversity, transmission capability, interconnection, demand-side flexibility, storage, and the characteristics of the existing generation fleet [2–4].

For this reason, the study does not assign a fixed storage duration or a universal integration surcharge to wind or solar. Any such value would depend on chronological Iranian demand and renewable-resource profiles, network constraints, interconnection, curtailment, available flexibility, and the penetration level of variable generation. Applying a single generic adder would therefore imply a level of precision that the present dataset cannot support.

Nuclear generation is treated on the same system boundary. The high production factor assumed for IHNPP reduces the nameplate capacity required to supply the reference annual energy, but each 1,255-MWe unit represents a large discrete generating infeed. Transmission capability, planned refuelling and maintenance outages, credible unit trips, reserve arrangements, and grid recovery requirements therefore remain relevant to system integration. IAEA guidance similarly identifies the electrical-grid interface as an important condition for reliable nuclear-plant operation [26].

CCGT has a different system profile. It can provide dispatchable output and operational flexibility, but it remains dependent on continuous natural-gas supply. Under the thermodynamically consistent counterfactual developed in Section 3.2, producing 36.81 TWh/y of net electricity would require approximately 8.14–8.23 billion Nm³ of natural gas per year. The



national significance of this quantity depends on the opportunity value of the displaced gas, which may differ across domestic power generation, industry, petrochemicals, seasonal supply, and export markets.

The pathways therefore redistribute cost and risk rather than eliminating them. Wind and solar reduce continuous fuel exposure and support modular deployment, while their system contribution becomes increasingly dependent on temporal resource patterns and flexibility as penetration rises. CCGT provides dispatchability and comparatively flexible deployment but retains exposure to gas availability and direct combustion emissions. Nuclear generation offers high annual utilization and firm low-carbon output, while concentrating capital, financing, construction, regulatory, and programme-level delivery risk.

There is no defensible basis in the present dataset for declaring one pathway universally superior.

A more defensible comparison therefore proceeds sequentially: first by establishing whether each pathway can supply the required annual electricity; then by considering when that electricity is available relative to demand; next by identifying the associated network, reserve, storage, and flexibility requirements; and finally by examining whether the financing, contractual, and project-delivery conditions are sufficient to bring the asset into reliable commercial operation. The same framework also separates benefits captured by the project company from those accruing to the wider economy.

This sequence extends the comparison beyond plant-level cost while keeping the analysis within the limits of the available modelling evidence.

The results ultimately support a portfolio interpretation rather than a single-technology ranking. Firm low-carbon resources can complement variable renewable generation in deeply decarbonized systems [5], while system-specific studies also show that the economic value of new nuclear capacity depends on the available alternatives and the surrounding power-system configuration [6]. For Iran, the implication is not that a predetermined mix can be inferred from the present screening. Rather, nuclear, renewable generation, flexible thermal capacity, transmission, storage where justified, and demand-side flexibility should be evaluated as interacting resources within a common reliability and economic framework. The screening therefore identifies the system questions that must be resolved before a technology ranking can be considered robust; it does not substitute for the chronological analysis required to answer them.

3.5. Life-Cycle and Energy-Security Implications

Life-cycle considerations provide an additional boundary for interpreting technology comparisons. ISO 14040 and ISO 14044 require consistent definitions of goal, scope, functional unit, inventory, impact assessment, and interpretation [21,22], while the UNECE assessment provides a harmonized reference for electricity-generation life cycles [23]. The present study uses these sources to define the comparison boundary; it does not undertake a new comparative LCA for Iran.

The four pathways place environmental and resource burdens at different stages of their respective chains. CCGT requires continuous fuel extraction, processing, transport, and combustion. Solar PV and wind avoid continuous fuel consumption during operation but require materials, manufacturing, land, network infrastructure, component replacement, and end-of-life management. Nuclear generation has no fossil-fuel combustion during electricity production, but its life cycle includes uranium supply, fuel-cycle services, nuclear-grade construction, cooling systems, spent-fuel and radioactive-waste management, and eventual decommissioning.

Because a harmonized Iran-specific life-cycle inventory is not available for all four pathways under consistent system boundaries, no new comparative values for $\text{gCO}_2\text{e/kWh}$, material intensity, land occupation, water use, or waste generation



are calculated. Introducing isolated literature values derived from different functional units, geographical conditions, or life-cycle boundaries would create an internally inconsistent comparison.

The coastal location of IHNPP also requires a clear distinction between cooling-water withdrawal and consumptive water use. A large once-through or recirculating cooling-water flow cannot be interpreted directly as consumptive loss, and the environmental implications depend on the final cooling-system design, intake and discharge configuration, thermal limits, and site-specific marine conditions. A quantitative comparison with CCGT, solar PV, or wind would therefore require harmonized technology- and site-specific water boundaries.

The revised CCGT counterfactual nevertheless provides a useful physical indicator of fuel exposure. As derived consistently in Section 3.2, producing 36.81 TWh/y of net electricity with CCGT at the adopted Iran-specific efficiency range would require approximately 8.14–8.23 billion Nm³ of natural gas per year. This quantity is relevant to energy-security screening because gas used in the power sector can have competing seasonal, industrial, petrochemical, or export uses. The analysis does not assign a universal monetary value to this displaced gas.

The same distinction applies to emissions. The 16.45–16.63 MtCO₂/y CCGT counterfactual reported in Section 3.2 represents direct combustion emissions derived from fuel-energy input; it is not a cradle-to-grave comparison between CCGT and IHNPP. A life-cycle comparison would additionally require upstream gas supply, construction, fuel-cycle, materials, replacement, waste-management, and decommissioning inventories for all pathways under a common functional unit.

Wind and solar also contribute to energy security by reducing dependence on continuous fuel supply. Their exposure is shifted toward resource variability, equipment and material supply chains, network development, power-electronic equipment, replacement logistics, and the flexibility required elsewhere in the system. These risks differ fundamentally from fuel-price and fuel-availability exposure and should not be treated as equivalent categories.

Nuclear generation has a different security profile. Large electricity output can be supported by comparatively small physical fuel volumes and long refuelling intervals, reducing exposure to continuous bulk-fuel delivery. At the same time, nuclear operation depends on specialized fuel-cycle services, qualified suppliers, nuclear-grade components, regulatory continuity, technical capability, and long-term arrangements for spent fuel and radioactive waste. For IHNPP, the project risk register confirms that vendor dependence, localization, supply-chain continuity, finance, and geopolitical conditions remain material programme exposures.

These characteristics should not be reduced to a simple claim of “fuel independence.” Nuclear, renewable, and gas-based pathways are exposed to different combinations of domestic resources, imported technologies, specialized supply chains, infrastructure, and institutional capacity.

Energy security is therefore better understood as the diversification and redistribution of exposure than as the elimination of risk.

For Iran, this distinction is particularly relevant because the electricity system must manage fuel availability, seasonal demand, network development, capital constraints, technology access, and long-term decarbonization simultaneously. A diversified portfolio can reduce dependence on a single fuel, technology, or supply chain while preserving complementary sources of firm capacity, flexibility, and low-carbon generation. IHNPP can contribute to such a portfolio if its financing, construction, regulatory, grid, fuel-cycle, vendor, and supply-chain requirements are managed explicitly rather than treated as external assumptions.



The present screening therefore treats life-cycle performance and energy security as comparative decision dimensions, not as additional numerical scores to be combined with LCOE or RPN.

3.6 Limitations

First, IHNPP remains a project under development, and the project-specific inputs used in this study represent the current planning basis rather than final EPC terms, audited construction accounts, or operating experience. The USD 25.0 billion CAPEX is an adopted screening case rather than a final contractual or financed project cost, while the 93% production factor, 10% internal consumption, electricity tariff, OPEX, working-capital requirement, and construction profile remain subject to refinement as design, procurement, licensing, financing, and construction progress. The sensitivity analysis therefore evaluates the dependence of the screening results on selected assumptions rather than predicting the final economic performance of the completed project.

Second, the CCGT, solar-PV, and wind assumptions are screening inputs rather than site-specific operating forecasts. The renewable capacity-factor ranges are informed by published Iranian studies, but actual project performance would depend on location, technology selection, resource variability, degradation, availability, and grid conditions. CCGT utilization is likewise dispatch-dependent. The revised CCGT gas and CO₂ counterfactuals are internally consistent because they are derived from the same thermal-energy basis, but they remain screening calculations. The 44.7–45.2% CCGT efficiency range is taken from published Iranian evidence, whereas the 36.0 MJ/Nm³ natural-gas lower heating value is an explicit engineering assumption in the absence of a project-specific gas-composition dataset. Accordingly, the resulting gas-use and direct-emission ranges should not be interpreted as site-specific measurements or life-cycle emission factors. All alternative-pathway capacity factors are treated as effective net-to-grid values to maintain a common annual-energy boundary, but the present analysis does not establish chronological system-service equivalence. It therefore does not calculate storage requirements, curtailment, transmission reinforcement, reserve requirements, LOLE, EENS, ELCC, or other adequacy metrics. Resolving those quantities would require harmonized hourly demand and resource profiles, generator availability, transmission constraints, operational reserves, and an explicit reliability criterion.

Third, the economic and risk analyses deliberately stop short of a fully probabilistic project-finance model. No definitive NPV, IRR, or DSCR is reported because a complete four-unit financing structure—including dated debt and equity drawdowns, interest during construction, fees, taxation, repayment terms, currency structure, escalation, and unit-specific commercial-operation dates—is not yet available. The financing-rate and construction-delay cases are deterministic stress tests, not estimates of the project WACC, confidence intervals, or probability-weighted forecasts. Similarly, RPN is retained as an ordinal, semi-quantitative prioritization index and is not converted into probability distributions, expected monetary losses, or nuclear-safety frequencies. The available documentation also does not fully reconstruct the upstream expert-elicitation process used to assign the original Severity, Occurrence, and Detection scores. Finally, the life-cycle component defines a comparative boundary rather than a new Iran-specific LCA, and no quantitative desalination revenue is retained because a complete technology, energy, CAPEX, OPEX, and offtake basis is not available.

These limitations define the evidentiary boundary of the study. The reported results should therefore be interpreted as screening-level relationships and project-specific decision conditions, not as substitutes for a bankable four-unit project-finance model, a multi-unit probabilistic safety assessment, a harmonized comparative LCA, or a chronological optimization of the Iranian electricity system.



4. Conclusions

The central conclusion of this study is that plant-level LCOE is not sufficient for comparing electricity pathways that differ materially in utilization, system contribution, financing structure, and project-delivery exposure. A defensible comparison must distinguish equal installed capacity from equal annual electricity and, in turn, distinguish annual-energy equivalence from equivalent system service.

Under the IHNPP reference assumptions, four nominal 1,255-MWe units provide 5,020 MWe of gross capacity. A 93% production factor combined with 10% internal electricity consumption gives 40.90 TWh/y gross and 36.81 TWh/y net electricity delivered to the grid. Under the revised central screening assumptions, matching this annual net output requires approximately 6.00 GW of CCGT at a 70% net capacity factor, 14.01 GW of onshore wind at 30%, or 18.27 GW of solar PV at 23%.

The sensitivity analysis also shows that the energy-equivalence result depends directly on the adopted nuclear production factor. Varying the IHNPP production factor from 85% to 95% changes net generation from 33.64 to 37.60 TWh/y. These values describe assumption dependence rather than a probability distribution for future plant performance. The resulting capacity differences reflect annual utilization only; they do not establish system-equivalent capacity and should not be interpreted as evidence that one technology is inherently more economical than another.

The economic screening uses USD 25.0 billion as the reference CAPEX case, equivalent to approximately USD 4,980/kW gross. Annual OPEX and overhaul expenditure is approximately USD 441.70 million, and the USD 0.05/kWh tariff case gives approximately USD 1.84 billion/y of electricity-sale revenue at the reference generation level. The deterministic sensitivity tests show that these headline values are not sufficient on their own to establish bankability. Changing CAPEX, electricity tariff, production factor, financing conditions, or construction timing materially changes the economic screening. In particular, the long construction profile makes financing exposure sensitive to both the assumed financing-rate proxy and additional years of financing carry.

A second conclusion is that project bankability and national economic value must remain analytically separate. Electricity-sale revenue can support project cash flow only when it is backed by a credible PPA, a creditworthy offtaker, and an enforceable payment-security mechanism. Physical gas displacement, avoided combustion emissions, and broader energy-security effects may be important at the national level, but they should not be added to lender-available project cash flow unless an explicit monetization mechanism exists.

Under the internally consistent CCGT counterfactual used in the revision, replacing the IHNPP reference generation with gas-fired electricity would require approximately 8.14–8.23 billion Nm³ of natural gas per year and would correspond to approximately 16.45–16.63 MtCO₂/y of direct combustion emissions. These quantities are physical counterfactuals rather than comparative life-cycle results or guaranteed economic benefits.

The project-risk analysis reinforces the economic interpretation. The controlled register contains 309 risks, including 19 Super Critical and 54 High risks; together, these two classes represent 23.6% of the register. Financial and economic risks contain 26 of the 73 priority risks (35.6%), while the maximum RPN of 224 is associated with PPA, electricity-export, and payment-bankability conditions.

These findings do not imply that RPN is a probability or a monetary risk measure. The framework is risk-informed rather than risk-monetized: the register identifies which project conditions warrant management attention, while the economic sensitivity analysis evaluates selected variables independently of the ordinal risk scores. The priority ranking also does not supersede nuclear-safety or regulatory judgement. Safety-significant, radiological, security, and licensing issues remain



governed by deterministic requirements, defence-in-depth, and regulatory criteria even when their project-management RPN is moderate.

The comparison does not identify a universal technology winner. Wind and solar offer modularity and freedom from continuous fuel supply, but their system contribution depends increasingly on temporal resource profiles, networks, and flexibility as penetration rises. CCGT provides dispatchable and flexible generation while retaining continuous gas and combustion-emission exposure. Nuclear generation can provide high-utilization firm low-carbon output, but it concentrates capital, financing, construction, regulatory, supply-chain, and large-unit integration requirements.

The appropriate interpretation is therefore portfolio-based rather than technology-exclusive. For Iran, nuclear generation, renewable resources, flexible thermal capacity, transmission, storage where justified, and demand-side flexibility should be assessed as interacting system resources rather than as isolated substitutes. The present screening does not determine an optimal portfolio; it identifies the conditions that a subsequent chronological system analysis would need to represent.

Within such a portfolio, IHNPP can contribute substantial firm low-carbon generation if the assumed plant performance is accompanied by credible control of financing cost, construction schedule, PPA and payment security, currency exposure, licensing, vendor dependence, supply-chain continuity, and grid-interface requirements.

Two extensions are required before the pathways can be ranked on a genuinely system-equivalent and financeable basis. First, a chronological Iranian power-system model should combine hourly demand, renewable-resource profiles, generator availability, transmission constraints, reserve requirements, storage, and explicit adequacy criteria. Second, a dedicated four-unit project-finance and probabilistic delivery model should represent unit-specific construction schedules, contractual cash flows, financing terms, and independently justified probability distributions rather than probabilities inferred from RPN. Moving beyond LCOE changes the questions that must be answered before electricity pathways can be ranked. For IHNPP, those questions concern finance, project delivery, and system integration as much as reactor performance itself.

Acknowledgments

The authors acknowledge the technical support and project documentation made available by Iran Hormoz Nuclear Power Plants Company for the project-specific feasibility, economic, and risk-assessment components of this study.

Author Contributions

A.K. conceived the study, developed the risk-informed full-system screening framework, performed the calculations and comparative analysis, interpreted the results, and prepared the original manuscript. **P.P.**, **N.M.S.**, and **A.B.S.** contributed scientific supervision, technical review, interpretation of results, and critical revision of the manuscript.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data Availability

Publicly available data used in this study can be accessed through the cited sources. Project-specific feasibility, financial, and risk-register information is subject to organizational access and confidentiality restrictions. Accordingly, only aggregated and non-sensitive project information required to reproduce the calculations reported in the manuscript is presented.



References

- [1] International Energy Agency and OECD Nuclear Energy Agency, Projected costs of generating electricity 2020. OECD Publishing, Paris, 2020.
- [2] F. Ueckerdt, L. Hirth, G. Luderer, and O. Edenhofer, System LCOE: what are the costs of variable renewables? *Energy* 63 (2013) 61–75.
- [3] L. Hirth, The market value of variable renewables: the effect of solar and wind power variability on their relative price. *Energy Econ.* 38 (2013) 218–236.
- [4] OECD Nuclear Energy Agency, NEA system cost analysis for integrated low-carbon electricity systems: a guide for stakeholders and policymakers. NEA No. 7668, OECD Publishing, Paris, 2024.
- [5] N. A. Sepulveda, J. D. Jenkins, F. J. de Sisternes, and R. K. Lester, The role of firm low-carbon electricity resources in deep decarbonization of power generation. *Joule* 2 (2018) 2403–2420.
- [6] X. Kan, F. Hedenus, and L. Reichenberg, The cost of a future low-carbon electricity system without nuclear power—the case of Sweden. *Energy* 195 (2020) 117015.
- [7] N. Ghorbani, A. Aghahosseini, and C. Breyer, Transition towards a 100% renewable energy system and the role of storage technologies: a case study of Iran. *Energy Procedia* 135 (2017) 23–36.
- [8] V. Aryanpur, M. Fattahi, S. Mamipour, M. Ghahremani, B. Ó Gallachóir, M. D. Bazilian, and J. Glynn, How energy subsidy reform can drive the Iranian power sector towards a low-carbon future. *Energy Policy* 169 (2022) 113190.
- [9] A. H. Saedi and A. Ahmadi, Life cycle assessment of Iran energy portfolio: renewable energy replacement approach. *Energy Sci. Eng.* 11 (2023) 1798–1817.
- [10] M. Nasouri and N. Delgarm, Bushehr Nuclear Power Plants (BNPPs) and the perspective of sustainable energy development in Iran. *Prog. Nucl. Energy* 147 (2022) 104179.
- [11] A. Kiyani, N. Mansour Sharifloo, and A. Bahrami Samani, From energy choices to SMR deployment: a system-level comparative assessment of nuclear power (SMRs), fossil fuels, and renewable energy options in Iran. *Adv. Energy Sci. Technol.* 1 (2025) 308–316.
- [12] A. Kiyani, P. Parvin, N. Mansour Sharifloo, and A. Bahrami Samani, A strategic feasibility-to-deployment framework for small modular reactors in Iran's future energy mix: integrating techno-economic assessment, site-risk analysis, water-energy nexus and safety compliance. *Adv. Energy Sci. Technol.* 1 (2026) 403–427.
- [13] S. Edalati, M. Ameri, M. Iranmanesh, H. Tarmahi, and M. Gholampour, Technical and economic assessments of grid-connected photovoltaic power plants: Iran case study. *Energy* 114 (2016) 923–934.
- [14] H. Mohamadi, A. Saeedi, Z. Firoozi, S. Sepasi Zangabadi, and S. Veisi, Assessment of wind energy potential and economic evaluation of four wind turbine models for the east of Iran. *Heliyon* 7 (2021) e07234.
- [15] OECD Nuclear Energy Agency, New perspectives for financing nuclear new build: minimising the cost of capital by optimising risk management. OECD Publishing, Paris, 2022.
- [16] M. Asadi, I. Larki, M. M. Forootan, R. Ahmadi, and M. Farajollahi, Long-term scenario analysis of electricity supply and demand in Iran: time series analysis, renewable electricity development, energy efficiency and conservation. *Sustainability* 15 (2023) 4618.
- [17] Intergovernmental Panel on Climate Change, 2006 IPCC guidelines for national greenhouse gas inventories, volume 2: energy, chapter 2: stationary combustion. Institute for Global Environmental Strategies, Hayama, Japan, 2006.
- [18] International Organization for Standardization, ISO 31000:2018, risk management—guidelines. ISO, Geneva, 2018.
- [19] International Electrotechnical Commission, IEC 60812:2018, failure modes and effects analysis (FMEA and FMECA). IEC, Geneva, 2018.
- [20] International Atomic Energy Agency, Technical approach to probabilistic safety assessment for multiple reactor units. Safety Reports Series No. 96, IAEA, Vienna, 2019.
- [21] International Organization for Standardization, ISO 14040:2006, environmental management—life cycle assessment—principles and framework. ISO, Geneva, 2006; Amendment 1:2020.
- [22] International Organization for Standardization, ISO 14044:2006, environmental management—life cycle assessment—requirements and guidelines. ISO, Geneva, 2006; Amendment 1:2017; Amendment 2:2020.
- [23] United Nations Economic Commission for Europe, Life cycle assessment of electricity generation options. United Nations, Geneva, 2021.
- [24] B. K. Sovacool, A. Gilbert, and D. Nugent, Risk, innovation, electricity infrastructure and construction cost overruns: testing six hypotheses. *Energy* 74 (2014) 906–917.
- [25] J. R. Lovering, A. Yip, and T. Nordhaus, Historical construction costs of global nuclear power reactors. *Energy Policy* 91 (2016) 371–382.
- [26] International Atomic Energy Agency, Electric grid reliability and interface with nuclear power plants. IAEA Nuclear Energy Series No. NG-T-3.8, IAEA, Vienna, 201.