

KRMH-500 MW: A Techno-Economic Framework for Multi-Technology Renewable Energy Integration and Storage at Khavda, Gujarat, India

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Abstract

Integrating renewable generation, energy storage and flexible electricity demand is an important consideration in the planning of large-scale renewable energy systems. This paper presents KRMH-500 MW, a proposed multi-technology renewable energy concept for the Khavda region of Kutch, Gujarat, India. The proposed generation portfolio comprises **343.90 MW of utility-scale solar PV, 150.00 MW of utility-scale wind and 6.10 MW of additional solar, wind and demonstration-scale technologies**, giving a nominal installed generation capacity of **500.00 MW**. The capacities of emerging and demonstration technologies are conceptual design assumptions and require technology-specific feasibility and site validation.

The proposed flexibility and conversion assets include a **35 MW/140 MWh lithium iron phosphate battery energy storage system**, a **20 MW/80 MWh conceptual gravity storage system** and a **10 MW green hydrogen electrolyzer** treated as an electricity-consuming load. A desk-based techno-economic screening methodology examines the generation portfolio, preliminary energy yield, storage boundaries, grid integration requirements and financial assessment framework.

The preliminary energy-yield assessment estimates annual generation of approximately 1,253.58 GWh/year in the technical base case. A separate conservative scenario of 1,092.5 GWh/year is used for preliminary financial modelling. These values are scenario-based estimates and have not been validated using site-specific resource measurements or independent operational data. Wind capacity factor is a major source of uncertainty, while several emerging technology components require further technical and commercial validation.

The study establishes a preliminary framework for site-specific resource assessment, hourly generation modelling, storage-dispatch optimisation, grid-integration studies and component-wise financial analysis. The results are screening estimates based on stated assumptions and secondary sources; they should not be interpreted as independently validated performance or as evidence of project bankability.

The 500 MW figure represents the sum of nominal installed generation ratings, including conceptual demonstration-scale assets; it does not represent firm capacity, net export capacity or a guaranteed supply rating.

Keywords: Renewable energy hybridization; solar PV; wind energy; energy storage; Khavda; techno-economic assessment; grid integration; green hydrogen.

2. Research Objectives and Contribution

- To define a 500 MW generation portfolio that integrates PV, wind and selected emerging or distributed solar technologies.
- To clearly distinguish between installed generation capacity, storage power, storage energy and the electricity used for hydrogen production.
- To provide a preliminary estimate of annual energy generation and to calculate the resulting blended capacity factor.
- To outline the regulatory, environmental and financial studies that are necessary to move the concept toward implementation readiness.
- To establish a foundation for further modeling while avoiding misrepresentation of conceptual assumptions as official government data.

This work contributes to a project-level synthesis of technology configuration, flexibility options, grid planning and the requirements for techno-economic validation. The configuration is an author-proposed conceptual design. It is not presented as a government-approved project, and the proposed capacities, locations and infrastructure arrangements remain subject to technical, commercial, environmental and regulatory validation.

3. Review of Policy and Technical Context

3.1 National planning and renewable integration

The Central Electricity Authority's National Electricity Plan provides a national-level framework for electricity generation planning in India [1]. However, it does not substitute for site-specific solar and wind resource assessments or project-level cost estimates for Khavda. The Ministry of New and Renewable Energy's annual reports provide additional context on national renewable-energy policies, programmes and sectoral developments [3]. These sources are used to establish the policy context rather than to claim that the proposed KRMH-500 MW configuration has been approved or independently validated.

3.2 Storage and operational flexibility

Energy storage can improve system flexibility by shifting electricity from periods of surplus generation to periods of higher demand. Its contribution depends on rated power, usable energy capacity, round-trip efficiency, storage duration, degradation, operating strategy and applicable grid and market requirements. The Central Electricity Authority's report on the optimal location of balancing energy sources and storage devices provides a planning reference for renewable-energy integration [2]. Storage is not a primary energy source: the net energy returned depends on charging input, conversion losses, auxiliary consumption and operating constraints.

3.3 Transmission access and grid compliance

A grid-connected project requires a technically feasible power-evacuation plan and compliance with applicable connectivity, transmission-access, metering, protection, forecasting, scheduling and grid-code requirements. The Central Electricity Regulatory Commission's Connectivity and General Network Access Regulations, 2022, as amended, provide the relevant regulatory framework for inter-state transmission access [4]. The applicable requirements must be assessed during project design and the grid-connectivity application process.

3.4 Research gap

A multi-technology renewable-energy portfolio can provide a useful basis for preliminary system-level screening; however, its assessment requires clearly defined accounting boundaries. Storage discharge must

be distinguished from primary electricity generation, and electricity consumed by electrolysis must be treated as a load rather than a generation contribution. Capacity factors must also be assigned according to technology-specific operating characteristics and supporting evidence. This study distinguishes these categories and identifies the principal data gaps requiring further investigation.

4. Methodology

4.1 Study design

This study does not include original site measurements, geotechnical investigations, detailed electrical-flow studies, a project-specific environmental impact assessment, vendor quotations or independent financial validation. Consequently, the results are preliminary and are intended for screening and research-planning purposes rather than investment appraisal.

4.1.1 Data Sources and Evidence Classification

The study classifies its inputs according to source, measurement basis, evidence quality and applicability to the proposed Khavda site. The classification distinguishes official planning data, manufacturer specifications, operational benchmarks, technology-level evidence and author-selected engineering assumptions. This distinction is important because performance and cost data from other projects or locations cannot automatically be assumed to apply to Khavda. Each model input should therefore be documented with its source, reporting period, calculation method, applicability and limitations.

4.2 Generation portfolio

Technology / asset	Installed generation capacity	Treatment in this study
Utility-scale solar PV	343.90 MW	Main solar generation block
Wind farm (HAWT)	150.00 MW	Main complementary generation block
CSP with molten-salt thermal storage	1.00 MW	Small-scale dispatchability demonstration concept
Perovskite tandem PV	2.00 MW	Emerging PV concept; commercial performance not assumed
Floating solar PV	2.00 MW	Small-scale floating PV concept; waterbody feasibility unverified
Vertical solar / BIPV [6]	0.50 MW	Building-integrated/vertical PV concept
Solar carport	0.50 MW	Canopy PV concept
Smartflower solar	0.05 MW	Small tracking PV demonstration
Aeroleaf micro-wind	0.05 MW	Small wind demonstration concept
Total generation	500.00 MW	Sum of generation assets only

Table 1: Proposed generation portfolio and technology treatment.

Note: The listed generation capacities sum to 500.00 MW. The smaller technology categories are conceptual demonstration-scale components whose commercial readiness, technical feasibility at Khavda and financial viability have not been established.

4.3 Separate flexibility and conversion assets

Asset	Proposed rating	Accounting boundary
LFP battery energy storage system	35 MW / 140 MWh	Storage; not additional primary generation
Gravity storage	20 MW / 80 MWh	Conceptual storage; requires technology/vendor validation
Green-hydrogen electrolyzer	10 MW electrical input	Controllable electricity-consuming load; Indicative output of 1,455–1,600 t/year derived in §6.5; revenue not assessed

Table 2: Flexibility and Conversion assets

The nominal energy-to-power ratios correspond to four hours at rated discharge power for each system: $140 \text{ MWh} \div 35 \text{ MW} = 4 \text{ hours}$ for the BESS and $80 \text{ MWh} \div 20 \text{ MW} = 4 \text{ hours}$ for the gravity storage system. These are nominal ratios and do not account for usable state-of-charge limits, round-trip efficiency, auxiliary consumption, degradation or operating constraints. The electrolyzer is excluded from the 500 MW generation portfolio because it consumes electricity rather than generating it.

4.4 Annual-Energy Calculation

We calculate energy generation separately for each technology before combining the individual contributions. For technologies represented using capacity factors we use the annual energy calculation:

$$E_i = P_i \times 8760 \times CF_i$$

Where, E_i is the estimated annual energy generation of component i , expressed in MWh/year; P_i is the installed generation capacity of component i , expressed in MW; and CF_i is the assumed capacity factor, expressed as a fraction.

$$CF_{\text{blended}} = \frac{\sum_i E_i}{P_{\text{total}} \times 8760} = \frac{1253.576}{500 \times 8760} \approx 28.62\%$$

Where, $\sum_i E_i$ is the sum of the annual generation estimates for all included generation components and P_{total} is the total installed generation capacity. The blended capacity factor is calculated using gross estimated generation in this study; it should not be interpreted as a net-export capacity factor unless auxiliary consumption, storage losses, curtailment and electrical losses have been consistently accounted for.

The technical base case and the conservative financial case are treated as scenarios. The technical base case represents component-by-component generation assumptions chosen for screening. The conservative financial case uses an annual energy assumption for preliminary financial modelling.

The energy model must distinguish operational data from resource-based estimates. When an input already represents metered generation, we do not apply additional loss deductions unless the boundary and excluded losses are explicitly identified. For technologies lacking operating data we document availability, wake losses, auxiliary consumption and other adjustments separately. The resulting annual energy estimates remain preliminary until the component calculations, source data and energy boundaries have been independently verified.

4.5 Techno-economic boundary

A robust financial assessment requires documented assumptions for capital expenditure (CAPEX), annual operation and maintenance expenditure (OPEX), land and lease costs, taxes, insurance, degradation, component replacement, auxiliary consumption, financing structure, construction schedule, discount rate,

electricity selling price, curtailment and storage dispatch. Because these inputs have not been fully established through project-specific studies, supplier quotations and a reconciled financial model, this study does not report definitive numerical values for net present value (NPV), internal rate of return (IRR), levelized cost of electricity (LCOE) or debt service coverage ratio (DSCR). These indicators should be calculated only after the assumptions, cash flows and system boundaries have been documented and validated.

5. Preliminary Results

5.1 Capacity mix

Indicator	Preliminary result	Interpretation
Total installed generation	500.00 MW	Generation assets only
Solar PV and solar-related categories, including CSP	349.95 MW	70.0% of total generation capacity
Wind generation (utility wind + micro-wind)	150.05 MW	Approximately 30.0% of total generation capacity
LFP BESS	35 MW / 140 MWh	Separate storage asset
Gravity storage	20 MW / 80 MWh	Separate storage asset
Electrolyzer	10 MW input	Flexible demand; not generation

Table 3: Installed generation capacity and separate flexibility assets.

The solar-related total includes utility-scale PV (343.90 MW), CSP (1.00 MW), perovskite tandem PV (2.00 MW), floating PV (2.00 MW), vertical/BIPV (0.50 MW), solar carport PV (0.50 MW), and Smartflower PV (0.05 MW). These categories total 349.95 MW.

Adding 150.00 MW of utility-scale wind and 0.05 MW of Aeroleaf micro-wind gives total installed generation capacity of 500.00 MW. The capacity shares are rounded to one decimal place.

5.2 Preliminary annual energy

Technology	Capacity (MW)	CUF / energy assumption	Estimated annual generation (GWh/year)	Generation share (%)	Evidence grade
Utility-scale solar PV	343.90	Operational benchmark transferred from Banaskantha; Khavda applicability unverified	843.92	67.32%	Transfer caveat
Utility wind	150.00	Wind scenario; base 30% CUF	394.20	31.45%	Low-confidence assumption
Floating solar PV	2.00	Solar-derived placeholder	5.08	0.41%	Site validation required
Perovskite tandem PV	2.00	Solar-resource-equivalence assumption	4.91	0.39%	Project performance unverified

CSP with thermal storage	1.00	Assumed 35% CUF	3.07	0.24%	Non-comparable benchmarks
Solar carport	0.50	Audited model assumption	1.23	0.10%	Site-specific validation required
Vertical PV/BIPV	0.50	Assumed 22% CUF	0.96	0.08%	Technology-transfer limitation
Aeroleaf micro-wind	0.05	Low-confidence estimate	0.11	0.01%	Manufacturer energy data unavailable
Smartflower	0.05	Per-unit midpoint (4,800 kWh) × 20 units	0.096	0.01%	Manufacturer output assumption
Total	500.00	—	1,253.58	100%	Preliminary scenario

Table 4: Preliminary annual energy table

The annual generation estimates are scenario-based rather than measured operating results. The 28% capacity factor used for utility-scale PV is a transferred benchmark whose applicability to Khavda has not been independently established. The 30% utility-wind capacity factor is an author-selected screening assumption pending a site-specific wind-resource assessment and independently validated energy-yield study. The smaller technology estimates also require technology-specific evidence, including model ratings, expected operating conditions and supplier performance data. Accordingly, the total of 1,253.58 GWh/year should be interpreted as a preliminary technical base case, not as a guaranteed annual generation forecast.

The Smartflower annual generation estimate of 96,000 kWh/year (0.096 GWh/year; 20 units × 4,800 kWh) is an illustrative assumption within the manufacturer's published location-dependent annual-output range [5]. The selected model, number of units and aggregate installed rating must be verified before the capacity and annual-energy entries can be finalised. The annual-output figure is not a guaranteed yield for Khavda and should be replaced by a model-specific estimate using local resource conditions when available [5]. As an additional Gujarat operational comparison, the reported CUF of the 100 MW Raghnesda Solar Park may be examined using GIPCL's investor presentation for the reporting period ending 30 September 2024 [7]. These operational figures are presented only as a regional comparison; they do not establish the CUF of the proposed KRMH-500 MW plant at Khavda or independently validate the Banaskantha benchmark used in the base case.

The technical base case is estimated at 1,253.58 GWh/year using the component-level assumptions reported in Table 4. The conservative financial case of 1,092.50 GWh/year is approximately **12.85%** below the technical base case of 1,253.58 GWh/year (**161.08** ÷ 1,253.58). The high-generation scenario is specified as 1,273.90 GWh/year for illustrative comparison. The conservative and high-generation scenarios are preliminary assumptions and have not yet been derived from independently validated

component-level resource and loss models. Before use in a detailed financial assessment, each scenario should document the technology-specific capacity factors, availability, electrical losses, auxiliary consumption, curtailment and other applicable adjustments.

Wind generation represents a material uncertainty in the overall energy assessment because the adopted 30% capacity factor has not been verified using site-specific wind measurements or an independently validated wind-yield study. The low, base and high wind scenarios should therefore be evaluated separately. The final results should also document the treatment of wake losses, turbine availability, electrical losses and auxiliary consumption to avoid either omitting or double-counting losses.

5.3 Interpretation of Preliminary Results

The preliminary energy-yield estimates indicate that the proposed 500 MW generation portfolio could produce approximately 1.25 TWh of electricity annually under the stated scenarios. However, annual generation alone does not establish firm power capability, round-the-clock renewable supply, guaranteed delivery or commercial viability.

The proposed storage portfolio comprises a 35 MW/140 MWh battery energy storage system and a 20 MW/80 MWh conceptual gravity storage system. Their combined nominal energy capacity is 220 MWh, corresponding to four hours at rated discharge power for each system individually. Actual deliverable energy and operating duration will depend on usable state-of-charge limits, round-trip efficiency, auxiliary consumption, degradation and dispatch strategy.

The 10 MW electrolyzer is treated as an electricity-consuming load rather than a generation asset. Its operation would reduce electricity available for sale unless supplied by otherwise-curtailed generation or accounted for through a separate energy balance. An indicative hydrogen output is derived in Section 6.5; hydrogen revenue is not assessed. Operation near 8,000 h/year (Table 9) cannot be met from curtailed generation alone, so continuous operation requires storage or grid supply, to be modelled in the energy balance.

The 10 MW electrolyzer and any water-treatment system are electricity-consuming auxiliary loads, not generation assets. If a dedicated desalination or water-treatment system is implemented, its electricity use must be modelled separately from the electrolyzer load using the selected system's specific electricity consumption and treated-water requirement. Net electricity available for export must account for these loads, other auxiliaries, transmission and electrical losses, storage charging/discharging losses, and curtailment. Water-treatment electricity demand remains unquantified pending technology selection and vendor data.

6. Grid Integration and Implementation Considerations

6.1 Electrical architecture

A 400 kV double-circuit evacuation arrangement may be examined as one preliminary design option. However, the appropriate voltage level, number of circuits, conductor configuration, line length, reactive-power compensation, fault levels, N-1 security and connection point have not been determined. These parameters must be established through a detailed grid-integration and transmission-planning study in consultation with the relevant transmission utility and system operator [4], [8].

6.2 Required technical studies

- Resource and generation simulations using long-term solar irradiance, wind speed, temperature and loss data are required

- Load-flow, short-circuit /dynamic stability, reactive power, harmonics, protection coordination and grid-code compliance studies are required [4].
- Assessments of transmission capacity, connectivity, access, metering, forecasting, scheduling and curtailment are required [8].
- Storage dispatch optimization, accounting for round-trip efficiency, depth-of-discharge, degradation, auxiliary loads and replacement assumptions, is required.
- Site screening of land titles, geotechnical conditions, drainage, dust/soiling, water availability, biodiversity, protected areas and statutory permissions are required.
- Vendor and EPC quotations, construction phasing, commissioning plans, O&M strategies, insurance and end-of-life management plans must be obtained or prepared.

6.3 Environmental and social screening

The proposed project requires site-specific environmental and land-suitability screening, including examination of protected-area boundaries, wildlife movement corridors, land-use records and applicable environmental and forest regulations. Inclusion of the Khavda region as the study location does not establish land availability, statutory approval or environmental acceptability. Similarly, the proposed floating-PV component requires identification of a suitable waterbody, confirmation of land and water-use rights, and assessment of ecological impacts and competing water demand. The feasibility of these components remains unverified.

If seawater desalination is adopted, environmental screening must cover the intake and screening system, concentrated-brine management, treatment chemicals, pipeline construction, marine/coastal ecology, land disturbance and sensitive habitats [14]. The applicable environmental and Coastal Regulation Zone requirements depend on the actual intake, discharge, plant and pipeline-route locations. The proposed concept has not obtained or demonstrated any such permission.

6.4 Operational challenges

Potential operational challenges include dust accumulation and soiling losses in solar PV systems, water availability for module cleaning, variability in solar and wind generation, and maintenance requirements for emerging technologies. These issues may affect net energy yield and operating expenditure. Site-specific resource assessment, cleaning-water planning and technology-level performance evaluation are required before operational and financial performance can be established.

6.5 Water Demand and Preliminary Treatment Capacity

For preliminary water-supply screening, this study adopts an assumed water intensity of 18–20 L/kg H₂ as a scenario informed by published hydrogen-production water-demand estimates [15]. This is an author-selected modelling assumption, not a universal design value or a complete plant water balance. The Government of India has reported a requirement of approximately 10 L/kg H₂ of demineralised water for electrolysis [12], [13]. These figures should not be added together because they represent different water-demand boundaries. The selected design must separately establish electrolyzer feedwater, treatment-system recovery and reject streams, and any cooling-water requirement.

For screening, hydrogen output is estimated from the electrolyzer's annual electricity use: 10 MW × 8,000 h = 80,000 MWh/year. At 55 kWh/kg this gives about 1,455 t/year, and at 50 kWh/kg about 1,600 t/year. Using this estimated production, the assumed 18–20 L/kg H₂ intensity gives a calculated water requirement of approximately 26,190–32,000 m³/year, equivalent to approximately 72–88 m³/day averaged over 365 days. Applying an illustrative 20–25% design allowance gives approximately 86–110 m³/day. This allowance is a preliminary modelling assumption and is not a supplier-validated design margin. The

resulting range should therefore be treated as a screening estimate, not as the final treatment-plant capacity. Cooling demand, treatment reject streams and other process-water requirements must be quantified separately before the total water-supply system is sized.

Option	Information to collect	Financial treatment
Purchased/delivered treated water	Supplier capacity, quality, delivered price, reliability and transport requirements	Water purchase, transport and storage costs
Suitable treated wastewater	Availability, seasonal reliability, quality, polishing requirements and supply agreement	Procurement, additional treatment, pumping and monitoring
Coastal desalination with treated-water transfer	Plant capacity, pipeline route and length, elevation, pumping, right-of-way and water quality	Desalination CAPEX/OPEX plus transfer infrastructure
Seawater transfer to inland treatment	Intake location, pipeline route, pumping, pretreatment, SWRO, polishing and reject-water arrangements	Intake, pipeline, pumping, treatment, brine management and permitting

Table 5: water-supply comparison table

Proposed desalination process. The conceptual process sequence is seawater intake → screening and pretreatment → seawater reverse osmosis (SWRO) → polishing and deionisation → product-water storage → electrolyzer feed. The design must also account for concentrate/reject streams and their appropriate management.

Land requirement and water-transfer infrastructure.

The proposed desalination and water-treatment system would require space for pretreatment, reverse-osmosis equipment, post-treatment and deionisation, chemical storage, treated-water tanks, pumps, electrical equipment, access roads and associated utilities. The land requirement cannot be reliably quantified at this screening stage because the equipment arrangement, storage duration, treatment capacity, redundancy, safety distances and supplier layout have not been established.

A further distinction is necessary because Khavda is an inland project location. Supplying seawater to a desalination plant at Khavda would require an appropriately designed seawater-transfer pipeline, pumping facilities and a route assessment. An alternative is to locate the desalination plant near the coast and transport treated water to Khavda. Both options require route surveys, hydraulic calculations, right-of-way assessment, land access, pumping-energy estimates and environmental screening.

Accordingly, no fixed land area or pipeline length is assumed in this study. The land requirement should be established from a preliminary engineering layout and the selected water-supply route. The associated pipeline corridor and access requirements must be evaluated separately from the land occupied by the desalination equipment.

7. Techno-Economic and Financial Assessment

7.1 Objective and Assessment Methodology

The financial assessment of the Kutch Renewable Multi-Hybrid Energy Plant (KRMH-500 MW) is aimed

at examining the potential capital investment, operating costs, revenue generation, financing structure and long-term economic viability of an integrated renewable energy project located in Khavda, Gujarat.

The proposed project combines large-scale solar PV, wind turbines, CSP with thermal storage, emerging PV technologies, floating PV, building-integrated/vertical PV, solar carports, and small solar- and wind-demonstration units.

The project also includes a 35 MW/140 MWh battery energy storage system (BESS), a conceptual 20 MW/80 MWh gravity energy storage system, and a 10 MW green hydrogen electrolyzer. The storage systems and electrolyzer are accounted for separately from the 500 MW generation portfolio. The electrolyzer consumes electricity and therefore does not add to installed electricity-generation capacity.

The assessment evaluates generation technologies, storage systems, hydrogen production, water supply, shared infrastructure and financing costs separately before consolidating them into a project-level financial model. This approach helps avoid double-counting and keeps the underlying assumptions transparent.

7.2 Capital Expenditure Estimation

Capital expenditure, known as CAPEX, represents the money needed to build and start up the plant. For a project of this scale, total CAPEX must cover the costs of generation equipment, energy storage, hydrogen production, land preparation, evacuation routes, electrical systems, civil construction, engineering work, project management and the financing that is required during construction.

The total project capital expenditure can be expressed as:

$$CAPEX_{\text{total}} = \sum_i CAPEX_i + CAPEX_{\text{common}} + IDC$$

where $CAPEX_i$ is the capital cost of component i , $CAPEX_{\text{common}}$ is the cost of common project infrastructure not already included in the component estimates, and (IDC) is interest during construction. Taxes, contingency, land, financing fees and other indirect costs must be included or excluded explicitly, with no double counting. This expression is a cost-accounting framework; it does not provide a numerical total until the required cost inputs are available.

IDC stands for interest during construction. The handling of contingencies, taxes, land fees and other indirect costs must be written out clearly so that no expense is counted twice.

7.2.1 Benchmarking of Major Technologies

The calculated benchmark subtotal for utility-scale solar PV, onshore wind, and a four-hour BESS is approximately ₹2,591.24 crore using the unrounded component calculations. This subtotal is not the total project CAPEX. It excludes, or has not yet separately quantified, the remaining generation technologies, gravity storage, the electrolyzer package, hydrogen compression and safety systems, water supply and treatment, land and site development, common electrical infrastructure, transmission evacuation, engineering and project-management costs, contingency, taxes and interest during construction, as applicable. The cost benchmarks are planning assumptions drawn from the CEA Madhya Pradesh resource-adequacy report [9], used as a national proxy; cost year to be stated, not vendor quotations or EPC prices for Khavda.

Component	Calculation	Indicative benchmark
Utility-scale solar PV	343.90 MW × ₹4.1 crore/MW	₹1,409.99 crore
Onshore wind	150 MW × ₹7 crore/MW	₹1,050.00 crore
Four-hour BESS	35 MW × ₹3.75 crore/MW	₹131.25 crore

Total using unrounded calculations		₹2,591.24 crore
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Table 6: Indicative capital-cost benchmarks for selected major components

7.2.2 Preliminary CAPEX boundary for the hydrogen water-supply system

The proposed 10 MW green-hydrogen electrolyzer requires a dedicated water-supply and treatment system. If seawater desalination is selected, the associated capital expenditure should be estimated separately from the electrolyzer package and the renewable generation assets. The cost boundary should include seawater intake and screening, pretreatment, seawater reverse osmosis, post-treatment and deionisation, product-water storage, pumping equipment, electrical and control systems, civil works, pipeline infrastructure, brine management facilities, engineering, procurement and construction (EPC), contingencies and interest during construction (IDC), as applicable.

For an inland location such as Khavda, the cost estimate must distinguish between a desalination plant constructed near the coast with treated-water transfer to the site and a water-treatment plant supplied through a seawater pipeline. These alternatives have different pipeline, pumping, land, permitting and operating-cost implications.

No project-specific CAPEX is assigned to the proposed desalination system in this study because the supply route, treatment capacity, equipment specification, pipeline length, discharge arrangement and vendor quotations have not been established. The complete project CAPEX must include the selected water-supply option once these parameters have been defined. The water-system cost must be consolidated into total project CAPEX without double-counting any cost already included in the electrolyzer, common infrastructure or EPC packages.

CAPEX component	Current value/status	Required action
Utility-scale solar PV	₹1,409.99 crore benchmark	Confirm cost year, scope and units in CEA source
Utility wind	₹1,050.00 crore benchmark	Confirm cost year, scope and units in CEA source
Four-hour BESS	₹131.25 crore benchmark	Verify that ₹/MW basis is consistent with the four-hour configuration
CSP with molten-salt storage	Not quantified	Obtain supplier/EPC estimate for the specified 1 MW demonstration system
Perovskite tandem PV	Not quantified	Obtain model- and project-specific cost evidence
Floating PV	Not quantified	Establish waterbody, anchoring, electrical and civil scope
Vertical PV/BIPV and carport PV	Not quantified	Obtain building/canopy structural and electrical cost estimates
Smartflower and Aeroleaf	Not quantified	Confirm number of units, ratings and supplier pricing
Gravity storage, 20 MW/80 MWh	Not quantified	Obtain technology-specific design and vendor quotation

10 MW electrolyzer and hydrogen balance of plant	Not quantified	Define electrolyzer package, compression, storage, safety and connection scope
Water supply and treatment	Not quantified	Compare the four water options in Section 6.5
Land, roads and site development	Not quantified	Complete site layout and land due diligence
Substation and evacuation	Not quantified	Complete grid study and transmission cost estimate
Common infrastructure, EPC and owner's costs	Not quantified	Define cost boundaries and avoid double counting
IDC, contingency, taxes and other indirect costs	Not quantified	Calculate using a defined construction schedule and financial model
Current identified benchmark subtotal	₹2,591.24 crore	Not total project CAPEX
Total project CAPEX	Not yet established	Complete all component estimates and reconcile the cost boundary

Table 7: Preliminary project CAPEX status and unresolved cost components.

7.3 Operating Expenditure Estimation (OPEX)

Operating expenditure (OPEX) comprises the recurring costs required to operate and maintain the project throughout its operational life. For KRMH-500 MW, component-specific operating costs should be estimated separately and subsequently consolidated with shared project costs. The principal cost categories are listed below.

1. Solar PV module cleaning, preventive maintenance, inverter servicing and replacement of components.
2. Wind turbine maintenance, blade inspection, gearbox and generator servicing and crane-related maintenance.
3. CSP receiver, heliostat, thermal storage heat-transfer system and turbine-generator maintenance.
4. BESS operation, management, battery monitoring and periodic replacement.
5. Gravity storage mechanical and electrical maintenance.
6. Electrolyzer maintenance, hydrogen compression, hydrogen handling and associated safety systems.
7. Land lease, security, staffing, insurance, communication systems, SCADA and administrative expenses.
8. Grid connectivity, transmission-related charges, auxiliary electricity consumption and other applicable operating expenses.
9. Water-supply operations, including pretreatment, seawater reverse osmosis (if selected), polishing and deionisation, pumping, membrane and filter replacement, treatment chemicals, water-quality monitoring, product-water storage, pipeline maintenance and brine management. Avoid duplicating electrolyzer maintenance or hydrogen compression already included in item 6.

The annual operating expenditure is calculated as the sum of component-specific operating costs and shared project costs:

$$OPEX_t = \sum_i^n OPEX_{i,t} + OPEX_{shared,t}$$

Where, $OPEX_{i,t}$ is the operating expenditure of the component i in year t , and $OPEX_{shared,t}$ represents common costs not already allocated to individual components. If an annual escalation rate is applied, a component's cost may be modelled as:

$$OPEX_t = OPEX_1(1 + g)^{t-1}$$

where $OPEX_1$ is the first-year operating expenditure and (g) is the annual escalation rate. The escalation rate must be supported by the project's financial assumptions and applied consistently. Component-level O&M percentages from government planning studies may be used for preliminary benchmarking but should not be substituted for a detailed O&M budget. A final project-level OPEX value cannot be established until the component-level assumptions and shared costs are reconciled.

The annual OPEX model for the hydrogen water-supply system should separately identify water-treatment electricity consumption, pumping energy, chemical consumption, membrane and filter replacement, labour, preventive maintenance, water-quality monitoring, brine management and any water-purchase or discharge charges. Electricity used by the water-treatment plant must be recorded as an auxiliary load and included in the energy balance. The model should use supplier-guaranteed specific electricity consumption, expressed in kWh per cubic metre of treated water, and the actual annual volume treated. No numerical desalination OPEX is claimed until these inputs and the selected water-transfer arrangement have been established.

7.4 Annual Energy Generation and Revenue Estimation

The revenue calculations presented in this section are illustrative gross-generation scenarios using an author-selected hypothetical selling price of ₹3.00/kWh for sensitivity analysis [10] [11]. They are not approved tariffs, awarded bid prices or forecasts of realised project revenue. Actual electricity revenue must be calculated using net saleable electricity at the applicable delivery point and the tariff or market price established by the relevant power-purchase agreement or sale arrangement. The energy balance must account consistently for electrolyzer consumption, water-treatment and pumping loads, storage charging and discharging losses, curtailment, and applicable transmission and auxiliary losses.

Scenario	Estimated annual generation	Hypothetical selling price	Illustrative gross revenue
Conservative	1,092.50 GWh/year	₹3.00/kWh	₹327.75 crore/year
Technical base	1,253.58 GWh/year	₹3.00/kWh	₹376.07 crore/year
High case	1,273.90 GWh/year	₹3.00/kWh	₹382.17 crore/year

Table 8: Illustrative gross electricity revenue under alternative annual-generation scenarios.

Note: Gross revenue is calculated as estimated annual generation multiplied by the hypothetical selling price. These values assume that all stated generation is saleable and exclude deductions for electrolyzer consumption, water-treatment loads, storage losses, curtailment and other applicable losses. The assumed price of ₹3.00/kWh is for sensitivity analysis only; it is not an approved tariff, awarded bid price or executed power-purchase agreement rate.

7.4.1 Financial Generation Scenarios

The conservative financial case of 1,092.50 GWh/year is adopted as a preliminary input for financial sensitivity analysis. The technical base case is 1,253.58 GWh/year, based on the component-level

assumptions in Table 4, including the illustrative Smartflower output of 96,000 kWh/year. The high-generation scenario is set at 1,273.90 GWh/year for comparison. All three values are scenario assumptions rather than verified operating outcomes, and the conservative and high cases require explicit component-level derivations before they can support a detailed financial evaluation.

For comparison purposes, this section calculates illustrative gross electricity revenue using an author-selected hypothetical selling price of ₹3.00/kWh. This value is an analytical assumption, not an approved tariff, an awarded bid price or an executed power-purchase agreement rate. The applicable tariff or market price for a future project would depend on the selected sale arrangement, procurement process and relevant regulatory framework [10] [11]. The revenue figures below assume that all stated annual generation is saleable. They therefore do not represent forecast realized revenue until the net electricity balance, delivery point, auxiliary consumption, storage losses, curtailment and contractual sale terms have been established.

7.5 Financing Structure and Cost of Capital

For preliminary financial modelling, a debt-to-equity ratio of 70:30 may be evaluated as a scenario assumption, subject to lender requirements, project bankability and the final financing structure. Sensitivity analysis should examine alternative financing ratios and their effects on WACC, equity returns and debt-service coverage.

The debt and equity amounts can be calculated as:

$$Debt = d \times C_f, Equity = (1 - d) \times C_f$$

Where, C_f is the defined financing base and d is the assumed debt proportion. Do not automatically equate the financing base to total project expenditure if some items are excluded from eligible financing.

The weighted average cost of capital (WACC) is expressed as:

$$WACC = \frac{E}{D + E} R_e + \frac{D}{D + E} R_d (1 - T)$$

Where, R_e is the cost of equity, R_d is, the cost of debt, and T is the applicable tax rate, subject to the selected tax and financing treatment.

The WACC must be calculated from internally consistent financing assumptions. In particular, the tax treatment, debt interest rate, equity return requirement, and timing of cash flows must be consistent with the project's financial model. A discount rate should not be inserted solely because it produces a favourable NPV.

7.6 Net Present Value

Net present value (NPV) measures the present value of the project's future cash flows after accounting for the initial investment. It is calculated as:

$$NPV = \sum_{t=0}^N \frac{CF_t}{(1 + r)^t}$$

CF_0 should normally include the initial project investment as a negative cash flow. The initial investment must not be deducted again if it is already included in CF_0 . For project NPV, the cash flows and discount rate must be defined on a consistent unlevered basis. Equity NPV, if reported, must instead use equity cash flows and an appropriate equity discount rate.

A positive NPV indicates that the project is expected to generate value above the selected discount-rate benchmark under the stated assumptions. A negative NPV indicates that the projected cash flows do not meet that benchmark. As project-specific annual cash flows and reconciled capital costs have not been finalised, a definitive NPV result is not reported in this preliminary assessment.

7.7 Internal Rate of Return

The internal rate of return (IRR) is the discount rate at which the NPV of the relevant cash flows equals zero:

$$0 = \sum_{t=0}^N \frac{CF_t}{(1 + IRR)^t}$$

Two distinct indicators should be reported:

- **Project IRR:** Calculated from project cash flows before debt financing.
- **Equity IRR:** Calculated from cash flows attributable to equity investors after debt financing and debt servicing

The two indicators are not interchangeable. Any reported IRR must identify the cash-flow basis, project life, construction period, financing treatment, and assumptions used. No final project IRR or equity IRR is claimed at this stage because the consolidated cash-flow model has not been validated.

7.8 Levelized Cost of Electricity

The levelized cost of electricity (LCOE) represents the discounted lifetime cost of electricity generation divided by the discounted lifetime quantity of electricity generated or delivered, depending on the selected system boundary. A general formulation is:

$$LCOE = \frac{\sum_{t=0}^N \frac{C_t}{(1+r)^t}}{\sum_{t=0}^N \frac{E_t}{(1+r)^t}}$$

where C_t represents the costs included within the defined system boundary and E_t represents the corresponding electricity output. The paper must state whether the output is gross generation or net electricity delivered and whether storage, replacement expenditure, hydrogen and grid evacuation are included in the cost boundary.

For KRMH-500 MW, the LCOE methodology must specify whether it includes generation assets only or also storage, hydrogen production, grid evacuation, replacement expenditure, and other common infrastructure. If the electrolyzer consumes electricity to produce hydrogen, its consumption must be accounted for consistently with the selected output boundary.

The calculation should also incorporate annual degradation, planned maintenance, component replacement, and the timing of capital expenditure. LCOE is not automatically equivalent to the tariff required to make the project financially viable; financing structure, taxes, revenue from ancillary services, and contractual arrangements can affect the required tariff.

A final numerical LCOE is therefore deferred until the costs, net energy output, and system boundary have been reconciled.

7.9 Debt Service Coverage Ratio

The debt service coverage ratio (DSCR) measures the cash available to service debt relative to the principal and interest payments due in a given period.

$$DSCR_t = \frac{CFADS_t}{Principal_t + Interest_t}$$

Here, $CFADS_t$ represents cash flow available for debt service in period t . The calculation should specify the treatment of taxes, working capital, reserve funding and other applicable adjustments.

A DSCR above 1.0 indicates that the cash available in the relevant period exceeds scheduled debt service, while a DSCR below 1.0 indicates a shortfall for that period. Lenders may require additional coverage depending on the financing terms and project risks.

The model should report minimum DSCR, average DSCR, and the year in which minimum coverage occurs. These indicators require a defined debt tenor, repayment schedule, interest rate, any moratorium, and annual cash flows. They cannot be reliably calculated from installed capacity or annual revenue alone.

7.10 Sensitivity and Risk Analysis

The integrated nature of KRMH-500 MW creates uncertainty in capital costs, energy generation, storage performance, operating expenses, and realised electricity prices. A sensitivity analysis should therefore be performed after the base financial model has been validated.

The principal variables to evaluate are:

1. Total project CAPEX and technology-specific cost overruns.
2. Net saleable electricity and renewable resource variability.
3. Tariff and realised electricity selling price.
4. Annual OPEX and escalation.
5. Discount rate and cost of debt.
6. Storage replacement costs and round-trip efficiency.
7. Project life and component degradation.
8. Construction delays and interest during construction.
9. Electrolyzer utilisation and hydrogen selling price, where hydrogen revenue is included.
10. Water-supply configuration, including desalination CAPEX, treated-water demand, specific electricity consumption, membrane replacement and treatment-chemical costs.
11. Water-transfer infrastructure, including pipeline length, pumping energy, land and right-of-way costs, brine-management requirements and any additional environmental or permitting costs.

The financial model should compare delivered treated water, suitable treated wastewater and seawater desalination using consistent assumptions for water availability, quality, reliability, CAPEX, OPEX and auxiliary electricity consumption. The preferred option should be selected on the basis of lifecycle cost, supply reliability and environmental acceptability rather than water-treatment cost alone.

Each scenario should report its effect on NPV, project IRR, equity IRR, LCOE, and minimum DSCR, as applicable. The base case and sensitivity cases should use the same financial-model structure so that the effect of each change can be interpreted consistently.

Case	Water source	Financial items to compare
A	Purchased or delivered treated water	Delivered price, transport, reliability
B	Suitable treated wastewater	Treatment cost, supply agreement, quality
C	Seawater desalination	CAPEX, OPEX, electricity, pipeline, brine management

7.11 Limitations of the Financial Assessment

The present financial assessment provides an initial benchmarking framework rather than a bankability assessment. The CEA values used for solar PV, wind, and four-hour BESS are planning assumptions at the stated historical price level; they are not quotations for construction at Khavda. The remaining technology components require project-specific cost evidence.

The preliminary annual energy estimate also requires validation of component-level capacity factors, losses, auxiliary consumption, storage dispatch, and net electricity sales. In addition, the final financial model must establish a consistent treatment of project life, degradation, taxes, depreciation, construction expenditure, debt repayment, storage replacement, and the electrolyzer's electricity consumption.

Accordingly, final NPV, IRR, LCOE, and DSCR values should only be reported after the integrated financial model has been reconciled. This approach avoids presenting unverified results as established financial performance.

7.12 Assessment Summary

The identified benchmark subtotal for utility-scale solar PV, onshore wind and the four-hour BESS is ₹2,591.24 crore, based on the unrounded component calculations. The difference between this subtotal and the sum of the individually rounded table entries is due to rounding. This amount is a partial capital-cost benchmark and does not represent the total project CAPEX. The remaining generation technologies, gravity storage, hydrogen production, water supply and treatment, land development, transmission evacuation, common infrastructure and other applicable project costs require separate estimation.

The financial feasibility of KRMH-500 MW will ultimately depend on the relationship between total installed cost, net saleable electricity, realised tariff, operating expenditure, financing conditions, and the operational value of storage and hydrogen production. A validated component-wise cash-flow model is therefore necessary before drawing conclusions regarding investment returns or bankability.

Parameter	Current value	Status / treatment
Total installed generation capacity	500 MW	Proposed configuration
Utility-scale solar PV	343.90 MW	Proposed capacity
Utility wind	150 MW	Proposed capacity
Other solar and wind demonstration technologies	6.10 MW	Proposed capacities; technology validation required
BESS	35 MW / 140 MWh	Proposed storage; 4-hour nominal ratio
Gravity storage	20 MW / 80 MWh	Conceptual storage; vendor validation required
Green hydrogen electrolyzer	10 MW electrical input	Flexible electricity-consuming load
Annual electricity generation — conservative case	1,092.50 GWh/year	Scenario input; derivation to be documented
Annual electricity generation — technical base case	1,253.58 GWh/year	Calculated from listed component assumptions
Annual electricity generation — high case	1,273.90 GWh/year	Illustrative high-generation scenario; derivation required
Blended capacity factor — conservative case	24.94%	Calculated from stated generation and 500 MW
Blended capacity factor — technical base case	28.62%	Calculated from stated generation and 500 MW

Blended capacity factor — high case	29.08%	Calculated only for the stated generation threshold
Electrolyzer operating hours	8,000 h/year	Author-selected assumption
Electrolyzer annual electricity use	80,000 MWh/year	Calculated from 10 MW × 8,000 h
Hydrogen electricity consumption	50–55 kWh/kg H ₂	Preliminary assumption; supplier validation required
Estimated hydrogen output	1,455–1,600 tonnes/year	Calculated from electricity input and specific consumption
Demineralised-water requirement	10 L/kg H ₂	Government-reported planning value [12], [13]
Estimated demineralised-water demand	Approximately 14,545–16,000 m ³ /year	Calculated from the estimated hydrogen output
Preliminary broader water-treatment capacity	86–110 m ³ /day	Conditional scenario only; boundary and design allowance must be justified
Utility PV capital-cost benchmark	₹1,409.99 crore	CEA planning benchmark; not a quotation
Utility wind capital-cost benchmark	₹1,050.00 crore	CEA planning benchmark; not a quotation
Four-hour BESS capital-cost benchmark	₹131.25 crore	CEA planning benchmark; not a quotation
Identified benchmark subtotal	₹2,591.24 crore	Includes only the three components above
Total project CAPEX	Not established	Requires component-wise costing
Annual project OPEX	Not established	Requires component budgets and shared-cost reconciliation
Illustrative selling price	₹3.00/kWh	Hypothetical assumption only
Gross revenue — conservative case	₹327.75 crore/year	Illustrative calculation before deductions
Gross revenue — technical base case	₹376.07 crore/year	Illustrative calculation before deductions
Gross revenue — high case	₹382.17 crore/year	Illustrative calculation before deductions
Debt-to-equity ratio	70:30 may be evaluated	Scenario assumption; not a committed financing structure
Cost of debt / interest rate	Not established	Requires financing evidence
Cost of equity	Not established	Requires financial assumptions
Project life	Not established	Must be defined for NPV, IRR and LCOE

Debt tenor and repayment schedule	Not established	Required for debt-service analysis
NPV	Not calculated	Do not report a numerical result yet
Project IRR / Equity IRR	Not calculated	Do not report a numerical result yet
LCOE	Not calculated	Requires consistent lifetime cost and output boundaries
Minimum / average DSCR	Not calculated	Requires annual cash flows and debt schedule
Payback period	Not calculated	Requires a defined cash-flow method

Table 9: Consolidated Technical and Financial Summary of the Proposed KRMH-500 MW Plant.

8. Discussion

The KRMH-500 MW concept illustrates the importance of evaluating renewable generation, energy storage, flexible electricity demand and grid integration within a common analytical framework. Installed capacity and annual energy generation alone do not establish the ability to supply firm power or meet a specific delivery profile. Storage can shift electricity across time, but its contribution depends on usable energy, conversion efficiency, operating constraints, degradation and dispatch requirements.

The preliminary generation assessment identifies wind capacity factor as a major uncertainty. The adopted solar generation estimate also requires cautious interpretation because the operational benchmark used in the calculation originates from a different district and has not been independently validated for Khavda. The performance of the smaller technology components, including CSP, perovskite tandem PV, floating PV, vertical PV/BIPV and Aeroleaf micro-wind, remains subject to technology-specific and site-specific validation.

The financial assessment is correspondingly preliminary. The available CAPEX benchmark covers only utility-scale solar PV, onshore wind and four-hour BESS. It does not represent the total project investment, while annual OPEX, net saleable electricity and financing assumptions remain to be established. Therefore, the current results do not demonstrate that the proposed configuration is more economical than a conventional solar-wind project or that it is commercially bankable.

A staged evaluation is recommended: first validate the resource and generation model, then assess storage dispatch and grid integration, and subsequently complete the component-wise financial model. The emerging technologies and hydrogen-production system should be assessed against clearly defined technical, operational and economic objectives. This approach would allow the proposed configuration to be evaluated transparently without treating conceptual assumptions as proven project performance.

9. Limitations and Future Work

- The study does not include a site-specific, hourly solar and wind resource simulation or an independently validated generation-yield assessment.
- The annual generation estimates are based on component-level assumptions that require further validation, including technology-specific performance, availability, electrical losses and auxiliary consumption.

- Vendor-backed capital and operating cost quotations are not available for several proposed technologies; their costs therefore remain unquantified or uncertain.
- There is no analysis of dispatch, storage optimization, curtailment, grid stability or transmission.
- The study makes no claims about clearances, land titles, water availability or wildlife impact.
- No bankable financial metrics are provided; indicators such as NPV, IRR, LCOE and DSCR need a reconciled model with assumptions.

Future research should: (i) build a generation model using official or traceable resource data; (ii) run dispatch optimizations to compare PV-wind systems against those with storage; (iii) validate interconnection and evacuation plans with the relevant utility; (iv) conduct thorough site and environmental screenings; and (v) publish an auditable financial model that includes sensitivity analysis.

10. Conclusion

The preliminary energy-yield assessment estimates annual generation of approximately 1,253.58 GWh/year for the technical base case, based on the component-level assumptions reported in this study. The estimate uses a 28% capacity factor for utility-scale solar PV and a 30% capacity factor for utility wind, together with preliminary assumptions for the smaller generation technologies. These inputs have not been independently validated for the proposed Khavda site. Consequently, the result represents a screening scenario rather than a guaranteed generation forecast.

The preliminary cost assessment identifies a benchmark subtotal of approximately ₹2,591.24 crore for utility-scale solar PV, onshore wind and a four-hour BESS. This subtotal is not the total project CAPEX. The remaining generation technologies, gravity storage, hydrogen production, water supply, grid evacuation, common infrastructure and other project costs require further quantification. The illustrative gross-revenue scenarios likewise do not establish net revenue or project profitability. A reconciled cash-flow model is required before numerical NPV, IRR, LCOE, DSCR or payback results can be reported.

Future work should prioritise site-specific resource assessment, component-level energy modelling, storage-dispatch optimisation, grid-connection studies, comparative water-supply engineering and a fully reconciled techno-economic model. The proposed configuration should be evaluated against a clearly defined reference case to determine whether the additional technologies and storage assets provide sufficient technical or economic value to justify their costs. The present study establishes a preliminary analytical framework for that evaluation; it does not establish construction readiness or commercial bankability.

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