



Green Hydrogen Pathways in India from a Grid Perspective

How RE mix, banking, grid-imports, and key policy levers influence cost and emissions

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Disclaimer: Preliminary Results – Peer Review in progress



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Executive Summary:

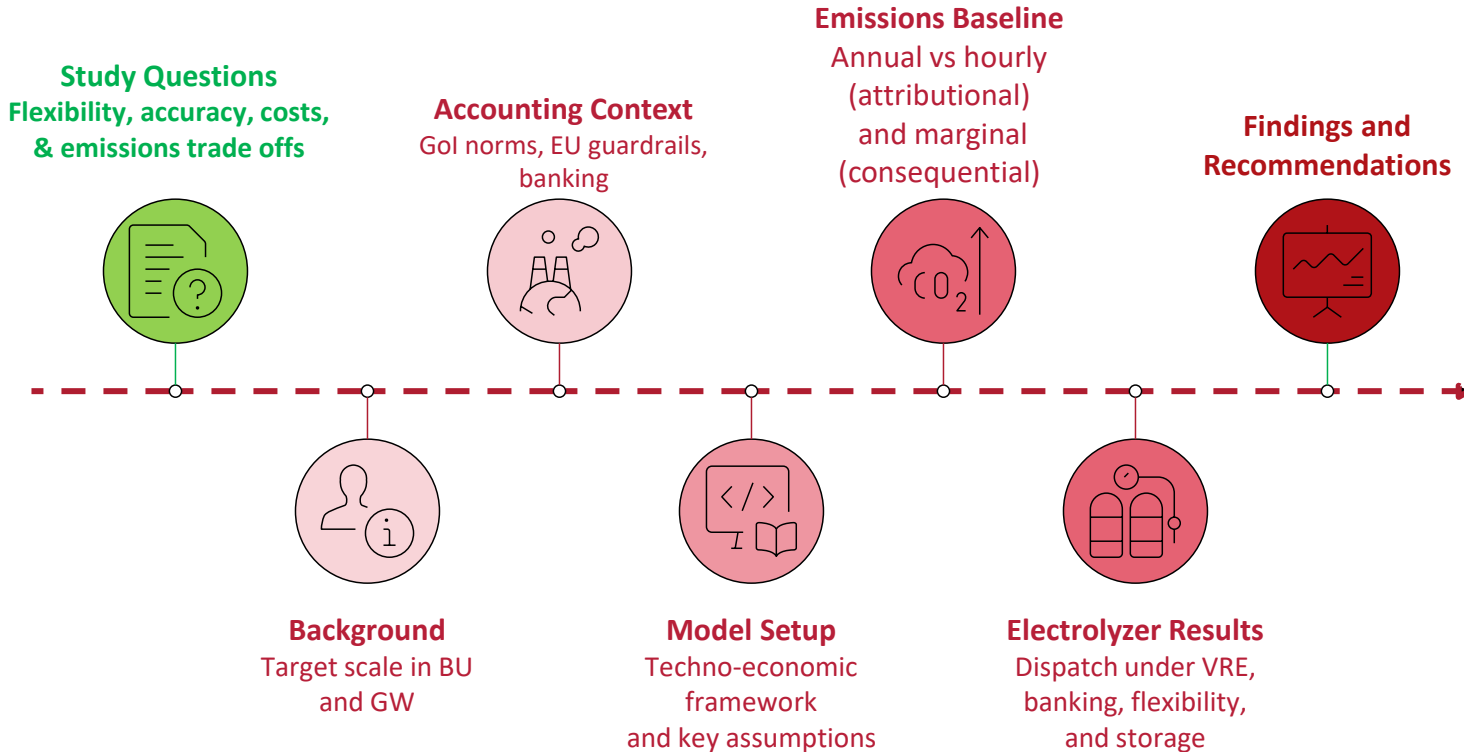
The “Greenness” of Hydrogen depends on the accounting norm

- Official norms for Green Hydrogen (gH₂) allow 2 kg-CO₂/kg-H – this is based on an *average annual emissions factor*
- We have built a model for a first-of-a-kind analysis of more granular (hourly) and precise emissions accounting, for both attributional and consequential emissions
 - Examines how an electrolyser can be operated under different policies of power sourcing options to understand the trade-off between flexibility, costs, and emissions

KEY FINDINGS

1. *Hourly accounting is important to accurately capture the true emissions impacts and to promote flexible operations, but can increase costs to comply with the 2 kg-CO₂/kg-gH₂ limit*
2. *India’s current norms differ from global norms and best practices, and this needs clarity, especially for export markets*
3. *Early green H deployment may be “opportunistic” (to be blended with grey hydrogen), enabling electrolyser demand flexibility*
 - *Flexibility can lower emissions and lower costs, but must be evaluated for global compliance (esp. for entities facing hourly emissions accounting requirements)*

Roadmap of the Green Hydrogen Analysis



Framing the Study:

How Green is “Green” Hydrogen, and at What Cost?

- How do **power-sourcing choices, demand flexibility, banking provisions,** and **policy levers** for green hydrogen jointly shape **cost (LCOH), emissions,** and grid requirements?
- How do different accounting norms (annual vs. hourly, attributional vs. consequential) impact reported emissions and electrolyzer operations?
 - Does the official norm of 2 kg-CO₂/kg-gH₂ *annual average* mean higher emissions based on hourly emissions?
 - What does this mean for exports, EU guardrails/CBAM, and national decarbonisation impacts?
- Does demand flexibility toward high-RE hours lower costs and emissions?
 - What are trade-offs through lower electrolyser CUF and higher capacity needs?

Background: Green Hydrogen is a Green Electricity Story

Key planning numbers on hydrogen scale, electricity needs, and renewable capacity are not yet fully aligned

2030 green H₂ target

National Green Hydrogen Mission: 5 MMT (million metric tonnes) by 2030
(supported by ~125 GW RE capacity)

Electricity and RE Requirement for the gH₂ Target

- 1 kg gH₂ ≈ 50 kWh electricity (electrolysis) → 5 MMT ≈ 250 BU/year (BU = billion units/kWh)
- 20th Electricity Power Survey (EPS) assumed 10 MMT with 50% co-located + 50% grid supply, implying ~250 BU/year drawn from the grid

Options for sourcing Power:

(1) Co-located RE | (2) Contracted off-site RE | (3) RE from the any green supplier / Market | (4) General grid supply

Firming options due to RE variability:

Oversize RE | Battery/PSP storage | Grid banking | Hydrogen storage

CONTEXT: 5 MMT gH₂ target implies ~250 BU/year demand
= ~1/7th of 2025 overall electricity demand
= Similar to total 2024-25 non-hydro RE generation

Emission Accounting for GH2 – What “Green” Means Under Various Norms

Official definition of green H: ≤ 2 kg CO₂/kg-H₂ threshold based on annual avg. Emission Factor (EF)

Options for Emission Accounting:

- Average Emission Factor (Annual) – MNRE methodology
- Average Emission Factor (Hourly) = share of grid’s hourly average emissions = **Attributional Accounting**
- Marginal Emission Factor (Hourly) = based on grid’s hourly marginal emissions (RE curtailment matters) = **Consequential Accounting**

Attributional vs Consequential Emissions (explained via a Simple Microgrid Example)

- (say) A renewable microgrid can fully charge 10 EVs
- Adding an 11th EV exceeds RE supply, so requires operating a diesel generator
- Attributional (average): diesel emissions are shared across all EVs
- Consequential (marginal): emissions are assigned to the 11th EV that triggers diesel

Both frameworks have value: Attributional for average reporting and foot-printing, and Consequential for marginal policy and decision impacts

- How “green” hydrogen emissions are measured or certified also depends on evolving **global certification guardrails**, viz.,
(1) incrementality (aka *additionality*); (2) temporal/geographic correlation (aka *deliverability*);
(3) temporal matching (e.g., *hourly matching*)
- India has other norms including “**banking**” of electricity (accounting offsets that time-shift excess RE generation)

Global debate on greenness of gH2 aka “guardrails”

EU’s Green Hydrogen Criteria, GHG protocol etc.

1. Incrementality (aka Additionality) — [Else zero-sum-game]

- Step 1 is easy – add “enough RE” to produce enough kWh (annual basis)
 - ◆ But this only remains fully green up to the point of NOT being surplus RE AND displacing coal 1:1 AND not using up preferential (high PLF) wind sites

2. Deliverability

- Depends on location and transmission

CEA has stated India’s grid is designed for regional and national deliverability, and so European deliverability norms of “bid zone” can extend almost nationally

3. Hourly Matching

- India’s MNRE norms allow electricity “banking” for 30 days
- India’s RECs (if usable) are multi-year or indefinite

Banking of electricity in India is allowed (but limited)

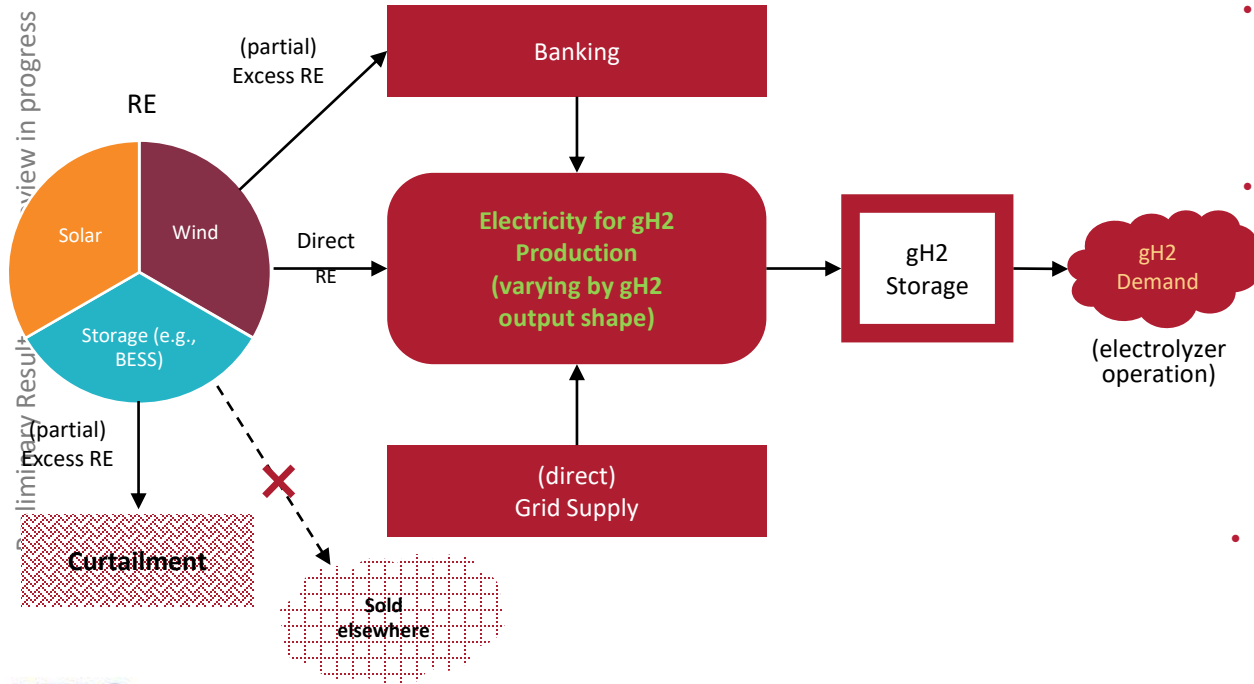
- Central policy leaves banking as per state/regulator norms
 - Charges differ by state: monetary/energy deductions and/or multiple additional grid fees
 - Usage rules
 - ◆ 30-day cycle
 - ◆ No inter-state banking norms available
 - ◆ States impose their own limitations
 - ▶ Caps, typically ~30% (sometimes ~10%)
 - ▶ Peak period banking to peak period withdrawal only (in some cases)

Banking violates EU accounting norms *and* creates costs for other stakeholders (similar to net-metering for rooftop solar)

- ◆ Lets users treat the grid like a battery, while paying little for it
 - ▶ The excess RE comes at a period of surplus, while withdrawal can be during peak periods
- ◆ Peak period supply may be coal, which has higher emissions

Techno-Economic Modelling of Green Hydrogen production

Multiple options for meeting electrolyser demand



Three-Step Modelling Approach

- Step 1: National Grid emissions estimation (exogenous)
 - Use CEA-based future grid mix
 - Estimate hourly grid emission factors (average & marginal) using economic dispatch models
- Step 2: Hydrogen optimisation (*main model*)
 - Objective: Minimise hydrogen cost (LCOH)
 - Optimise* around: **power sourcing**, gH2 storage, electrolyser operation, banking, and RE curtailment
 - Assume grid costs and time-block price spreads are based on recent power exchange Day Ahead Market (DAM) prices (**optimization is based on official (avg. annual) emission constraints of 2 kg-CO₂/kg-H₂**)
- Step 3: Calculate actual grid emissions
 - Use hourly grid emission factors from Step 1 to calculate system *attributorial* and *consequential* emissions

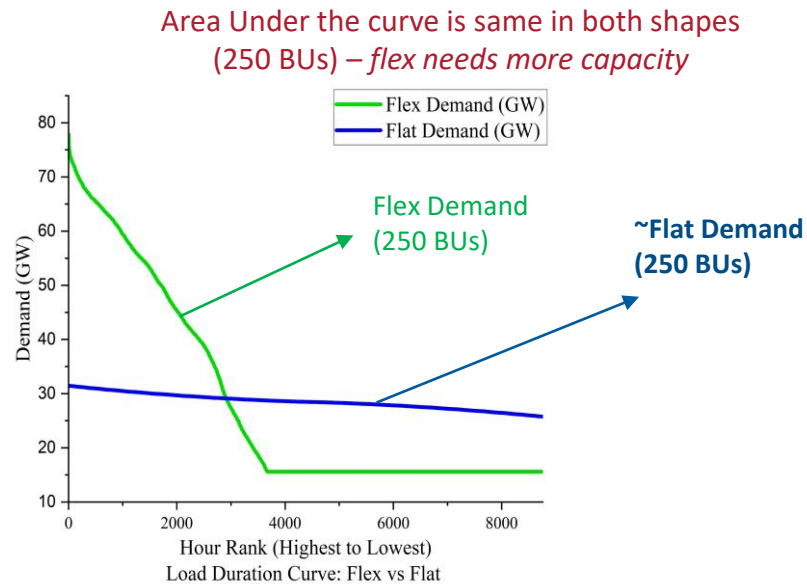
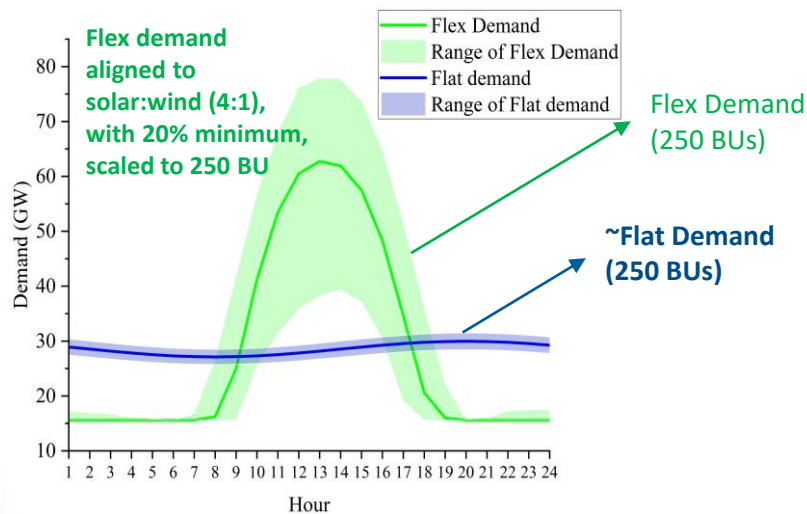
*Using GAMS, we run thousands of optimisations per case as an MIP, avoiding MINLP complexity while capturing operational variability and flexibility

What profile (shape) will national gH2 demand take?

Consequential emissions require comparing dispatch with and without gH₂; total load (~250 BU) is known, but its hourly demand shape (aka Electrolyzer input) must be estimated: RE aligned vs. ~flat

- CEA 2030 demand: ~2,280 BU including ~250 BU gH₂ load (6.46% CAGR) [CEA has not taken any specific gH₂ shape]
- Since we don't know the shape for aggregated gH₂ national demand, we assume 2 bounding variants: **~flat** OR **flexible** that aligns w/ RE

Preliminary Results – Peer Review in progress



2030 Grid Dispatch with Total Demand including gH2 Demand

(1) Attributional: Hourly Average Emission Factors

Government accounting uses annual average emission factors;
Hourly emission matters for accurate accounting

Preliminary Results – Peer Review in progress

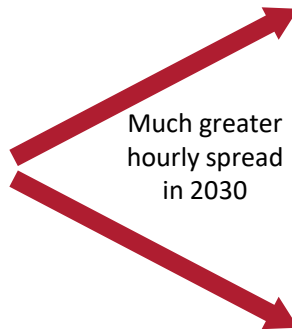
CEA'S 2025 Emission Factors

Annual Average EF:
727 g-CO₂/kWh

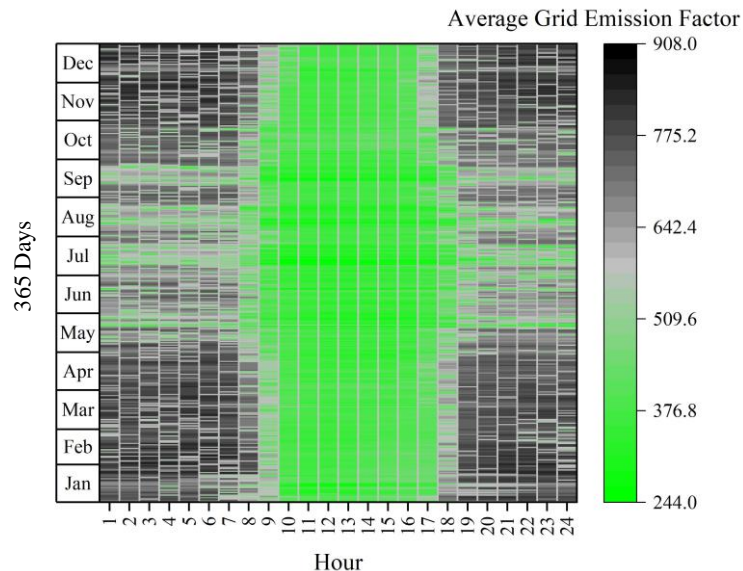


Calculated 2030 Emission Factors

Annual Average EF:
562 g-CO₂/kWh



Much greater
hourly spread
in 2030



Hydrogen's hourly emissions depend on the shape of its demand

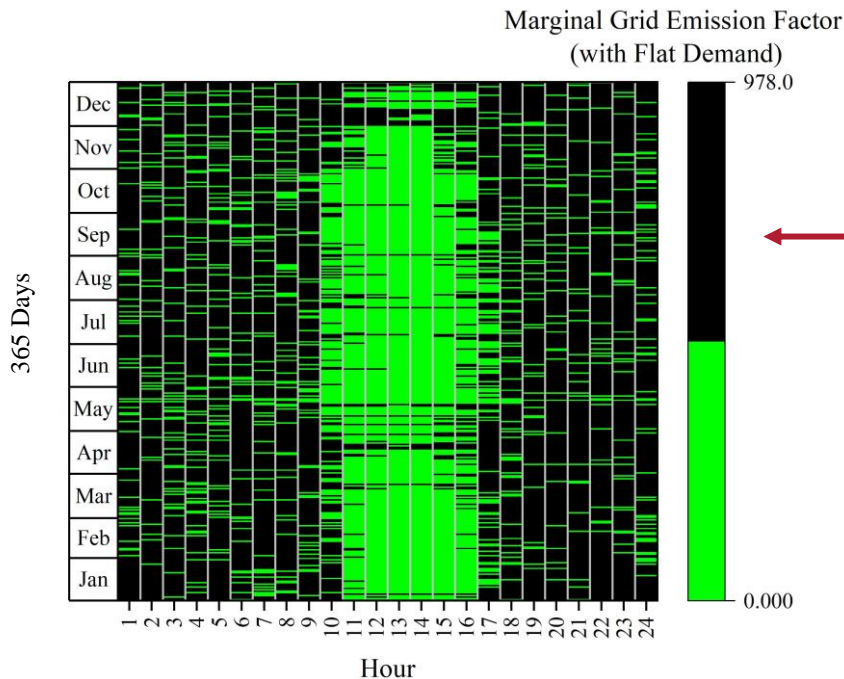
Since we don't know the exact shape of gH2 demand, we bound the problem with 2 bounding cases

- For the same 2030 total resource mix per CEA, RE-aligned H₂ demand adds ~0% emissions, while a ~flat H₂ profile raises emissions by ~6.4%
- However, fully RE-aligned operation is not cost-optimal for electrolyser operation, as shown later

2030 Dispatch with vs. without gH2 Demand

(2) Consequential: Hourly *Marginal* Emission Factors

Hourly marginal emission factor: **Either zero (RE curtailment)** or **978 gCO₂/kWh (coal is the swing producer)**



For flat gH2 demand case (shown on the left):
Annual Average of hourly *Marginal* Emission Factors
= **645.89** gCO₂/kWh

For flex gH2 demand case (not shown):
Annual Average of hourly *Marginal* Emission Factors
= **614.58** gCO₂/kWh

Optimisation: Flat Electrolyser Demand Case

Cheapest case: Solar only (wind is more expensive) with 100% Banking Allowed (thus no storage), plus grid imports [per MNRE norms using annual average grid EFs to stay within 2 kg-CO₂/kg-gH₂]

(Synthetic Case)
Solar + Banking (100% Allowed) + Grid Import

Flat gH₂ Electrolyzer Demand

	Levelized Cost of Hydrogen (LCOH) with banking		229.51 Rs/kg-gH ₂	
	<i>of which</i> RE cost		60.55%	
	<i>of which</i> Electrolyzer System cost (balance costs are for banking, grid imports)		36.57%	
	Emissions (ignoring banking) based on <u>annual average EF</u>		2.00	Accounting per MNRE norms
[kg-CO₂ per kg-gH₂]	Emissions (ignoring banking) based on <u>hourly time-block wise EF</u>	~ 25% Higher →	2.50	
	Emissions also <u>accounting for Banking</u> (Hourly Attributional)	~ 400% Higher →	10.01	
	Emissions also <u>accounting for Banking</u> (Hourly Consequential)	~ 850% Higher →	19.38	

The cheapest “compliant” option fails on two fronts:

- 1) States usually don't allow such quanta of banking (51% banked energy as per optimisation in the absence of wind)
- 2) Banking raises actual emissions dramatically (over 10 kg-CO₂/kg-gH₂ just on attributional hourly basis accounting)

Banking reduces costs but increases emissions

Case of solar *with wind supply* but no storage (flat demand)

Banking Allowed	Total Banking of energy need of Electrolyzer	LCOH [Rs/kg-gH ₂]	Grid Emissions with Banking (Attributional) [kg-CO ₂ /kg-H]
0%	0%	367.9	2.32 <i>Lower than 2.50 due to wind</i>
10%	10%	253.5	3.95
20%	20%	242.2	5.53
30%	30%	236.0	7.04
40%	37%	235.0	8.00
50%	37%	235.0	8.00

Banking *appears* cheaper but true costs are borne by other consumers (banking charges are nominal)
Discoms have to buy expensive evening power, while taking in RE from the developer when they have excess supply

Additional finding:
Banking (even 10 %) gives no extra value to adding storage (BESS)

More Practical Optimisation (Flat Demand Case): Banking capped at 10%, wind with solar, grid imports, no storage

[per MNRE norms using annual average grid EFs to stay within 2 kg-CO₂/kg-gH₂]

Flat gH₂ Electrolyzer Demand

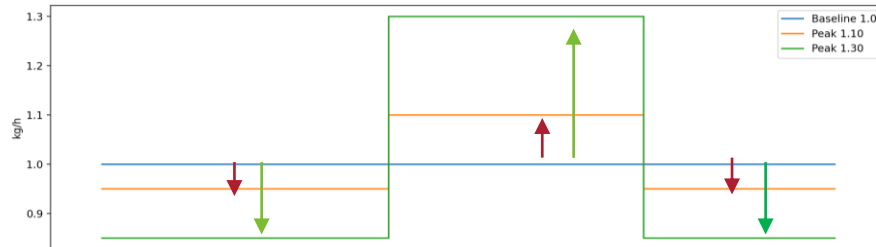
	Levelized Cost of Hydrogen (LCOH) with banking			253.71 Rs/kg-gH₂	
	<i>of which</i> RE cost			65.79%	
	<i>of which</i> Electrolyzer System cost (balance costs are for banking, grid imports)			33.08%	
[kg-CO₂ per kg-gH₂]	Grid Emission (ignoring banking) based on <u>annual average EF</u>			2.00	Accounting per MNRE norms
	Grid Emission (ignoring banking) based on <u>hourly time-block wise EF</u>	~ 21% Higher	→	2.42	
	Grid Emission <u>with Banking</u> (Hourly Attributional)	~ 100% Higher	→	3.95	
	Grid Emission <u>with Banking</u> (Hourly Consequential)	~ 200% Higher	→	6.11	

Note: We assume that excess RE banked can offset coal supply (a short term possibility)
If we assume zero emissions credit for banking exports, attributional emissions
increase from 3.95 to 5.91 kg-CO₂/kg-gH₂

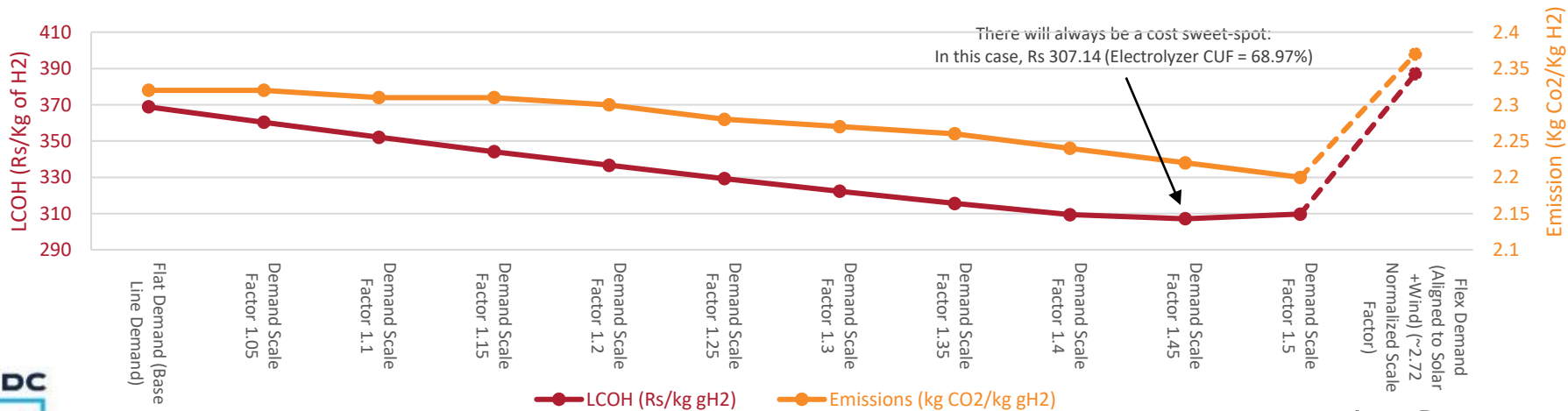
But what about H2 Demand Flexibility?

Demand-shape flexibility lowers LCOH, reduces emission factors, and achieves optimal electrolyser operation at ~69% CUF

Flexibility is modelled using a scaling factor (e.g., 1.5), shifting demand from non-solar hours to solar hours so annual hydrogen demand stays constant but becomes more RE-aligned.



Demand Flexibility vs LCOH vs Emission



More flexibility = higher peaks = larger electrolyzer (more capex)

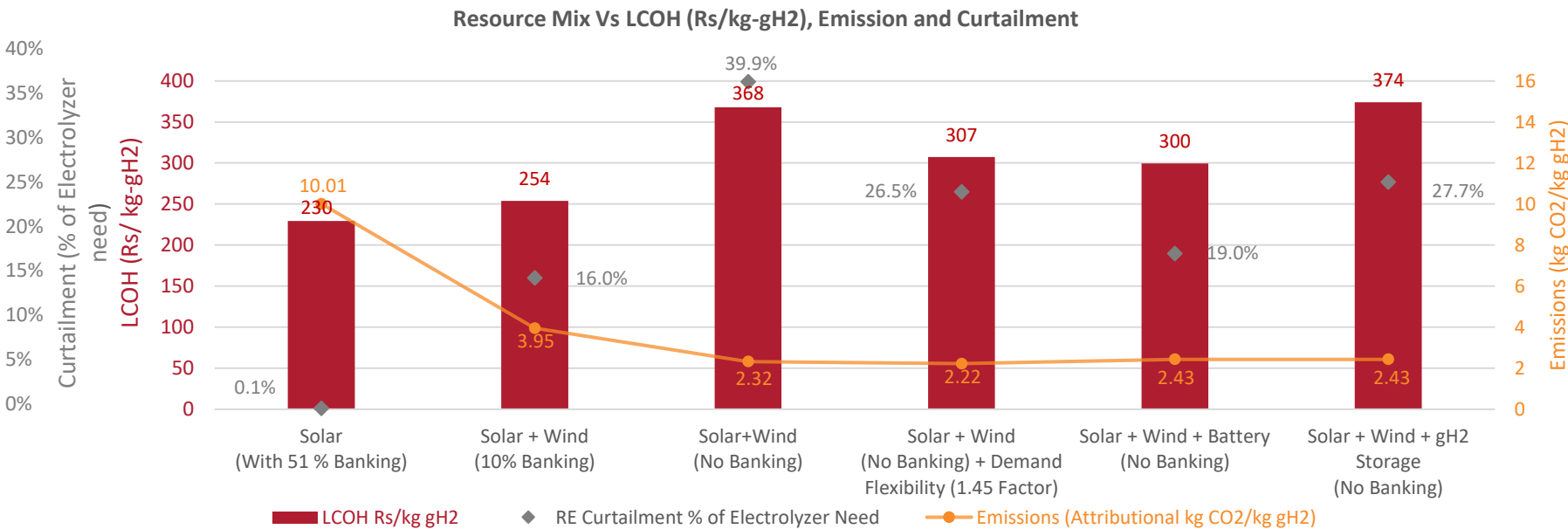
Thus, always a trade-off and sweet-spot for cheaper RE vs cheaper capex at higher Capacity Utilization Factor (CUF)

Storage – of Electricity (BESS) or gH2

- Without banking, electricity storage lowers LCOH by ~19% but raises attributional emissions by ~5%
 - Why? Because the grid interaction (including battery charging) can be during cheaper but dirtier time blocks
- Batteries are cheaper than extensive gH2 storage, which also raises emissions by about 5% (similar reason as demand flexibility)
 - Good news: In the longer run, cheap grid time-blocks will become cleaner
 - Today, the constraints are based annual average emissions, which is why actual emissions rise per calculations, but if we optimize with hourly constraints, emissions wouldn't rise (but costs would rise)

Comparing select options across cost, emission and RE curtailment

“Low cost” can mask higher emissions; use a cost + emissions + demand flex view

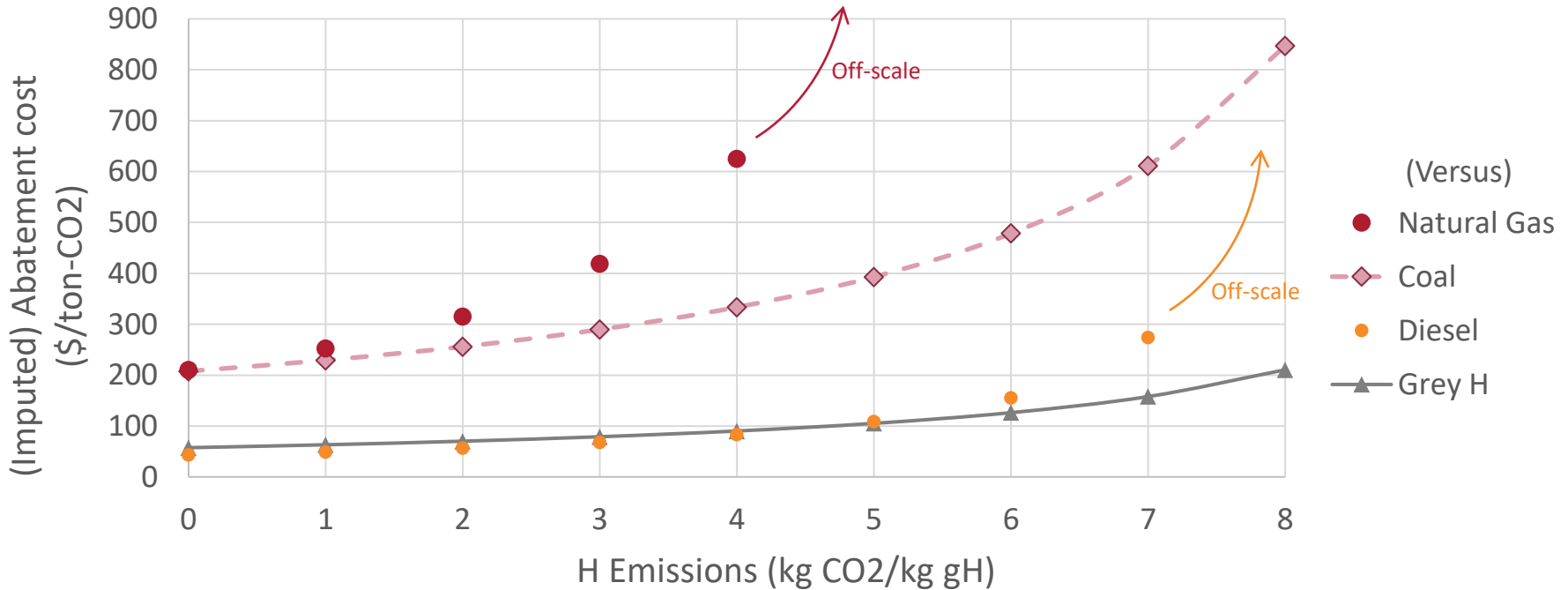


- Unlimited or coarse (average-EF) banking can lower LCOH but raise lifecycle/consequential emissions
- Demand flexibility is a cheap, effective way to cut both cost and emissions – but depends on the gH₂ output requirement
- BESS helps (unless banking dominates), H₂ storage is costly today
- More curtailment means more RE capacity required – with national planning implications
 - Thus: Minimize curtailment by pairing wind with flexibility, right-sized storage, and/or transmission upgrades



Higher gH2 emissions = higher abatement cost (\$/ton-CO2)

Delivered *fuel-only* basis comparison (vs. gH2 @ \$23/MMBTU)



Assumes:

gH2 @ Rs 250/kg
forex @ 95 Rs/US\$

Thermal Coal
3.8

Fuel Costs (\$/MMBTU)

Natural Gas
12

Diesel
20* (with lots of taxes)

Grey H
17.6
[11 kg-CO2/kg-grey-H]

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Findings and Recommendations (1)

- **Annual averages understate real gH₂ emissions**
 - *Gol's 2 kg-CO₂/kg-gH₂ norm allows limited grid drawal, but drawal typically occurs in low-RE hours. Hourly accounting raises emissions by ~25%, showing why time-block impacts matter*
- **Banking is cheapest, but shifts costs and emissions to the grid**
 - *Banking often gives the lowest LCOH and can appear near “zero-emission” under current norms. In reality, evening supply is often coal-backed, with costs borne by utilities and other consumers (and higher emissions).*
 - *This is not compliant for exports to the EU*
- **Alternative accounting reveals much higher emissions even under compliance**
 - *Hourly accounting alone within MNRE's frameworks (ignoring attributional/consequential) raises emissions ~25%*
 - *Attributional emissions are ~90% higher and consequential emissions 200%+ higher; Both methods are valid, answering average footprint vs marginal system impact*

Findings and Recommendations (2)

- **Green hydrogen can crowd out other decarbonisation benefits**
 - *Adding gH_2 demand to the 2030 grid increases grid emissions unless new RE is demand-aligned. Otherwise, “additionality” is incomplete, and “more RE” does not offset coal 1:1*
- **Demand flexibility lowers costs and emissions, but needs CAPEX trade-offs**
 - *Shifting production to high-RE hours accesses cheaper renewables, reducing LCOH and emissions. But it requires larger electrolysers, lowers CUF, and the sweet spot is ~70% CUF under today’s costs.*
- **Electrolyser performance must value flexibility, not only efficiency**
 - *Flexible ramping with variable RE enables operating at the sweet spot of CUF is central for cost-effective green hydrogen integration*

Findings and Recommendations (3)

- **Exports require alignment with global guardrails and CBAM-type rules**
 - *Europe is moving toward verifiable hourly accounting; annual averages or multi-year RECs cannot be apportioned to exports*
 - *CBAM PPAs already require hourly accounting, but RFNBO would require this by 2030*
- **“Opportunistic gH₂” and blending with grey hydrogen need clear standards**
 - *Early blending with SMR (grey) hydrogen may help flexibility, but can affect export eligibility and certification integrity*
- **Future policy must tighten accounting transparency, not just thresholds**
 - *The challenge is specifying hourly norms in advance and distinguishing banking-based compliance from truly matched supply*
 - *Phased hourly RECs and differential incentives (US IRA-style) can reward lower-emission pathways*

Appendices with more details/assumptions

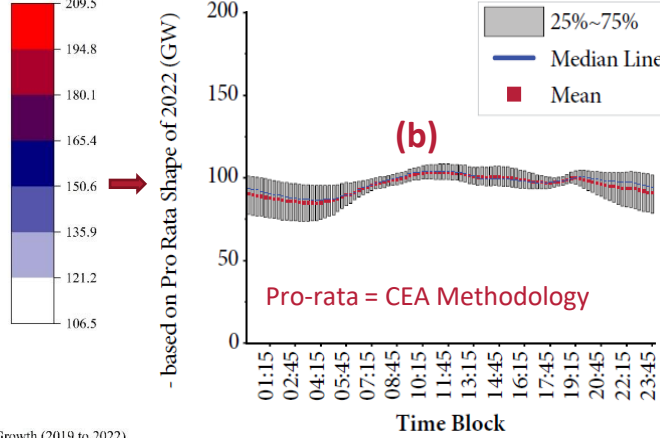
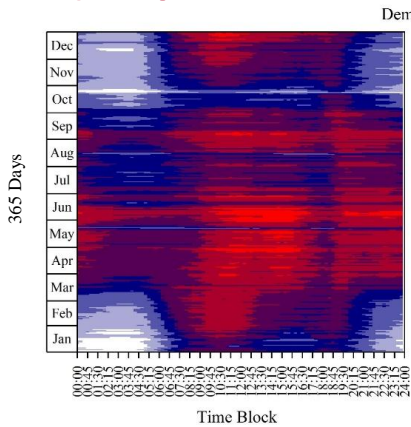
(please stay tuned for a more detailed report)

Model (selected) key assumptions

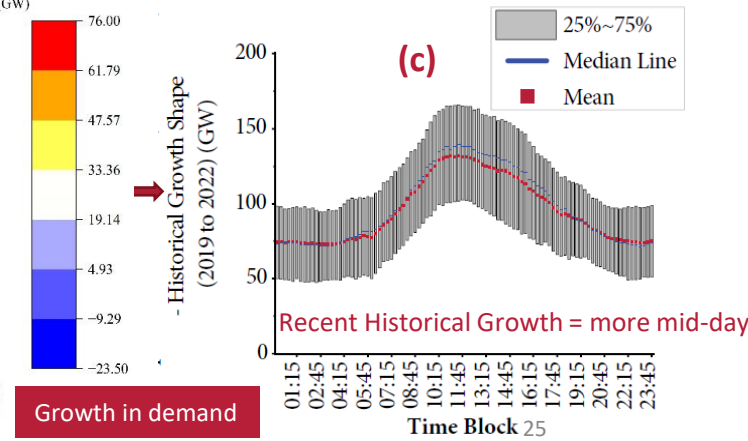
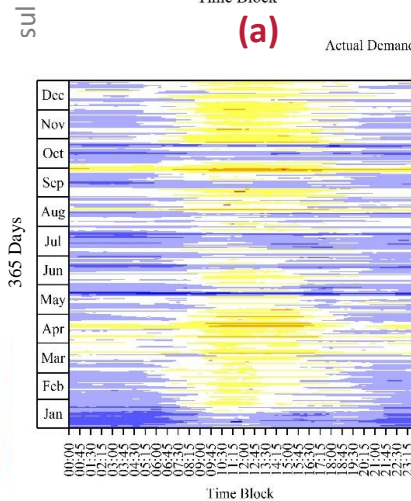
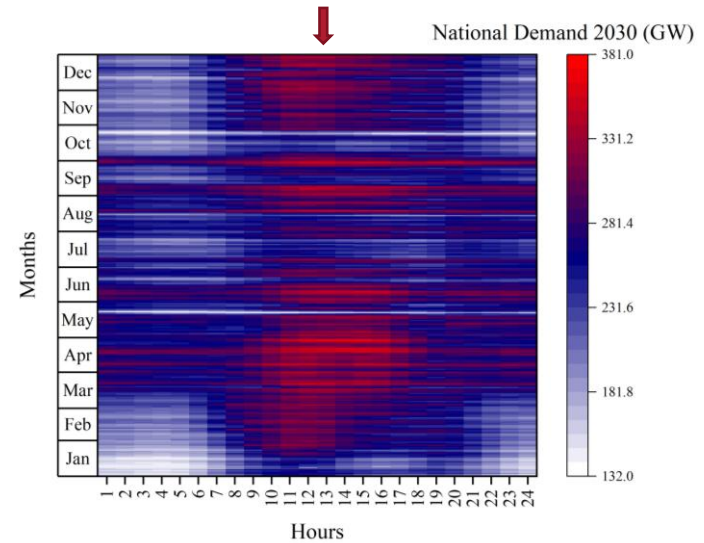
Focus is on effect of emissions accounting frameworks/policies than specific numbers

- State of the Grid (future supply mix) – Using CEA studies
- Shapes of electricity demand – *modified compared to CEA*
 1. Overall grid demand – modified from CEA's pro-rata extrapolation
 2. Green H₂ electricity demand – not explicitly part of CEA calculations (thus assume a range)
- National “Copperplate” grid (single grid with no transmission implications; any congestion would raise costs and/or emissions)
- No complex arbitrage of storage by developer or 3rd parties into the power exchange
- Grid: swing producer remains coal, *unless there's RE curtailment*
 - RE is “must run”* or at least lowest marginal cost (* up to technical limitations on coal)
- Any grid purchases will be based on power exchanges
 - Most RE is self-generated or contracted; no ad-hoc third-party PPAs
- We focus on well to electrolyzer gate, ignoring the energy (or emissions) to compress/transport gH₂
- Electrolyzer and Hydrogen Storage assumptions
 - \$650/kW capex; 3% O&M; 10.15% WACC; 10+ years stack life, alkaline electrolyzer with 30% minimum load
 - Banking cost @1.5 Rs/kWh
 - Hydrogen storage capex \$466/kg gH₂ with 4% O&M (including energy for compression)

Step 1: What will be the probable CY2030 national grid demand shape ? (Required for Emission Factor estimation for 2030)



Est. 2030 Total Demand Shape =
Existing Demand (a)
+
Growth
{Weighted avg. of pro-rata (b) and historical (c)}



Growth in demand