2026 KNS Fall Conference

Scenario Analysis of a Carbon-Free Energy System in an Isolated Regional Grid

With a Focus on SMRs

Input data · Scenario design · Simulation results

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Hypothetical isolated grid

Transmission build-out lags generation growth, tightening grid constraints

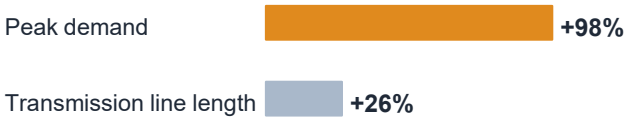
Transmission delays

150 months

Delay of the Bukdangjin–Sintangjeong 345 kV line

East Coast HVDC	**Delayed to Jun 2027**
Recent projects	**5–6 yrs (avg.)**

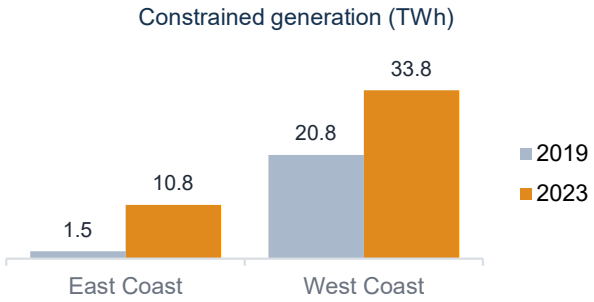
Growth, 2003→2023



More output constraints

7-fold

Rise in East Coast constrained output (2019→2023)

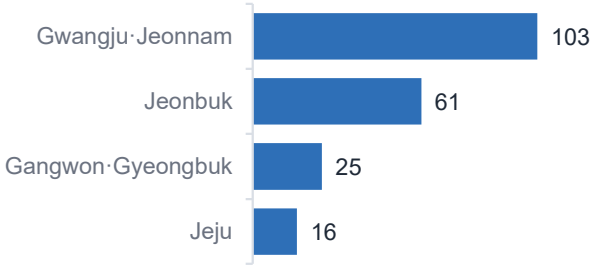


East Coast: 17.9 GW installed vs. 14.5 GW transmittable (2025)

Grid connection limits

205 substations

Designated May 2024; new connections restricted



Honam lifted Oct 2026 (41 of 87 reopen in phases, 2028–30)

Grid build-out alone is not enough → **So how are government and industry responding?**

Sources: MOTIE·KEPCO grid congestion measures (May 2024); MCEE Power Grid Innovation Plan (Sep 29, 2026); MOTIE data via Rep. Lee Un-ju (Oct 2024); KCCI SGI (Nov 2024); Kyeongin Ilbo (May 27, 2025)

Facing transmission delays, government and industry tuyrn to generation near load centers

2024.6

Ministry of Trade, Industry and Energy

Distributed Energy Act takes effect

"To address the problems of a centralized power system, such as social conflict over long-distance transmission, and build a local generation-for-local-consumption distributed energy system near demand"

2025.11–12

Ministry of Climate, Energy and Environment

7 Distributed Energy Special Zones designated

Nov: Gyeonggi, Busan, Jeonnam, Jeju

Dec: Gyeongbuk, Ulsan, Chungnam

e.g., Ulsan: 300 MW CHP supplying an AI data center directly

2026.1

Industry · Yongin semiconductor cluster

On-site generation for a large load

Of up to 16 GW of demand, 3 GW from LNG plants built near the cluster by three public gencos

The rest via long-distance lines from Honam, Gangwon, Gyeongbuk → growing opposition along routes

Rather than wait for new lines, supply near demand (distributed energy) → **SMRs (small/medium nuclear) are among distributed energy businesses**

Sources: MOTIE press release (Jun 13, 2024); MCEE press releases (Nov 5 & Dec 25, 2025); Kyunghyang Shinmun (Jan 11, 2026); Kyeongin Ilbo (2026)

SMRs are a distributed energy business: testing their role in an isolated grid

Why verification is needed

A DE business, but role unproven

DE Act: “small/medium nuclear” (≤500 MW/module)

Outside the DE scope of the Decree

SMR deployment is becoming real

One SMR in the 11th Basic Plan (Feb 2025)

Site call opened in Feb 2026

Operating alongside renewables

Complements or competitors?

Needs testing at the regional scale

National-scale analysis

Other plants absorb fluctuations,

SMRs may appear only as cheap

baseload, like large reactors

This study: isolated grid

Under maximal transmission limits,

check SMR use and fit with RE

→ benchmark for the distributed role

Why simulation?

Effects of demand patterns on output and prices

need a simulation with hourly demand, RE and plant limits

Source: Report Ch. 1, Ch. 2.3 (pp.14–15), Ch. 7.2.2, Summary (p.ix); Seoul Shinmun (Feb 21, 2025); Newsis (Feb 15, 2026)

Two research questions mapped onto three scenario axes

Q1

Under which demand pattern do SMRs contribute the most?

Demand patterns S1–S4

Same annual demand, different hourly profiles

Q2

How much do SMRs contribute to optimizing a regional carbon-free energy system?

RE levels Sa–Sd

Does more RE change the SMR effect?

With / without SMR

SMR (680 MW) included or not

Common indicators

- H2·ESS
- Capacity factor
- SMP
- System cost
- Curtailment

Source: Report Summary (p.x), Ch. 2.3 (pp.14–15)

Analysis flow: build data, design scenarios, run POSY, compare results

1 Build demand data

- Sector load patterns
- Regional scale & income
- Hourly demand by scenario

2 Build supply data

- Generation mix
- Fixed & variable costs
- Plant characteristics

3 Scenario design

Demand × RE × SMR combinations

4 POSY simulation

Inputs → hourly dispatch & capacity optimization

5 Compare & interpret

Demand pattern → Q1 / SMR on/off → Q2

Who does what

STEP 1–3
Researchers collect & process data, set assumptions, design scenarios

STEP 4
POSY computes hourly dispatch and H2·ESS capacity

STEP 5
Compare & interpret

Source: Adapted from Report Fig. 2-6 (p.15) and Ch. 3–6

KEPCO data (77) and Input-Output Tables (83) reclassified into 62 industries

KEPCO Power Data Portal

77 KSIC divisions

2023 hourly use (8,760 h)

BOK Input-Output Tables

83 mid-level sectors

2022 value added (extended table)

Matching rules

1 : 1	Motor vehicles ↔ Motor vehicles
n : 1	Metal ore + non-metallic mineral mining ↔ Metal & non-metallic minerals
1 : n	Basic metals ↔ Iron & steel + Non-ferrous + Castings
Excluded	No counterpart (e.g., mining support services)

62

integrated industries

Industries (62) + households + EVs = 64 sectors

Why mid-level?

Electricity-use and value-added data are published only down to this level

Why different years?

2022 was COVID-affected → patterns from 2023, value added from the latest 2022 table

Why separate households & EVs?

Demand that scales with population

Source: Report Ch. 3.1 (pp.17–20), Table 3-2

Indexing sorts 64 sectors by pattern; a representative industry for each of 5 types

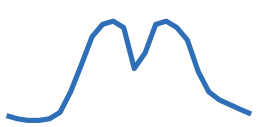
Why indexing, not standardization?

Standardization ($\frac{x-\mu}{\sigma}$) divides by the standard deviation, erasing each industry's own load pattern.

e.g., Coal & petroleum products: mean 1,506,396 MW vs. SD 7,952 MW, i.e., flat, yet standardization makes them look volatile → indexing adopted

Double-peak

Lunch dip, M-shape



Automotive

Intensity near mfg. average

Flat

Within ±10%



Electronics

Representative of 2038

Night-peak

Peak after 21:00

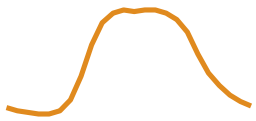


Basic metals

Only one in top-30 value added

Single-peak

Holds through lunch

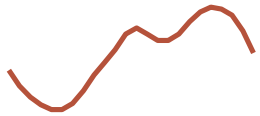


Wholesale/ retail

Largest value added, ubiquitous

Evening-heavy

21–24h mean > daily mean



Food & lodging

Best pattern fit

Other

Varies by industry

Patterns all differ, so no representative chosen

※ Curves are schematic illustrations of each type (not actual data)

Source: Report Ch. 3.2 (pp.21–30), Ch. 4.2.1 (pp.35–38), Table 4-4

Scenario logic: vary only the industry mix; fix generation and per-capita income

What we ask (Q1) How does the SMR contribution change with the demand pattern?

→ If anything other than the pattern changes, differences cannot be attributed to it, so variables fall into three types (example: S1 vs. S4, the sharpest contrast)

	S1 Manufacturing-led (automotive)		S4 Services-led (retail, food)
What we vary Treatment variable Industry value-added shares	40% / 15% / 15% / 15% / 15% Automotive, Electronics, Basic metals, Wholesale /retail, Food	≠	10% / 10% / 10% / 40% / 30% Automotive, Electronics, Basic metals, Wholesale /retail, Food
What we fix Control variables Same total generation & income	Annual generation 10 TWh Income $30,000 per capita	=	Annual generation 10 TWh Income $30,000 per capita
What we adjust Balancing variable Intensity gap → population	Population 437k → GRDP ≈ $13.1 bn	≠	Population 663k → GRDP ≈ $19.9 bn

Result Same generation and income across scenarios; only load shape, population and GRDP differ → results read as demand-pattern effects

Source: Report Ch. 4.1 (pp.31–34), 4.2.2–4.2.3 (pp.38–41)

Fix 10 TWh/yr and $30,000 per-capita income; scale by population

10
TWh / yr

Same in all demand scenarios

Substation basis

No regional-size standard → one 345 kV substation

~440k people × 10.6 MWh ≈ 4.6 TWh

→ one SMR (~4.8 TWh) covers it; scaled up

Municipal basis

Benchmarks: Gwangju 9.1 TWh · Daejeon 9.9 TWh

* Sejong (3.9 TWh) excluded: one SMR at ~66% CF could already cover it

Analytical purpose

SMR share of generation ≈ 50%

* Too low: RE swings drive SMR operation, blurring Q1; too high: an unrealistic mix

Income fixed, population adjusted

Per-capita GRDP $30,000

Based on G20 average of $30,760 (2023)

Population n

Adjusted to reach 10 TWh

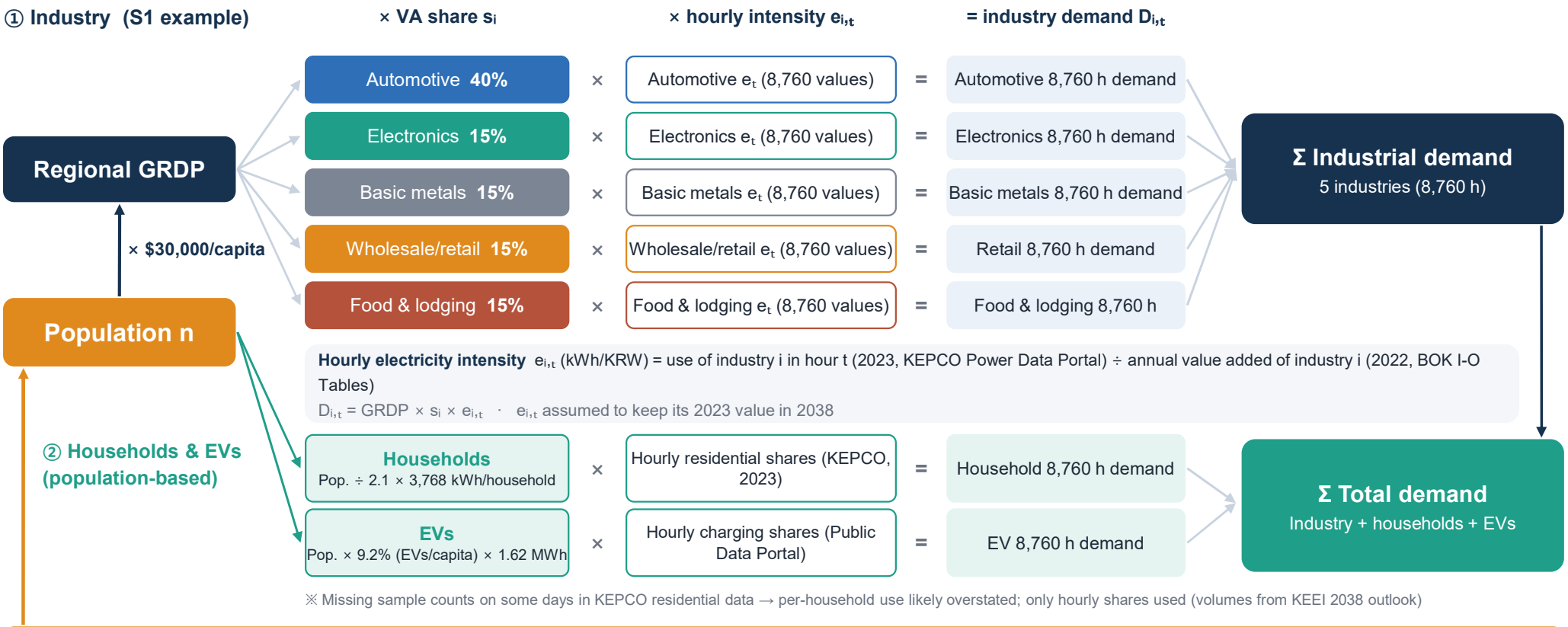
→ **Economic activity held constant, so only the demand shape differs**

Why fix per-capita rather than total GRDP?

With total GRDP fixed, changing industry shares misses 10 TWh because electricity intensities differ. Fixing per-capita GRDP and adjusting population keeps 10 TWh in every scenario (a static assumption).

Source: Report Ch. 4.1 (pp.31–34), Tables 4-1 to 4-3

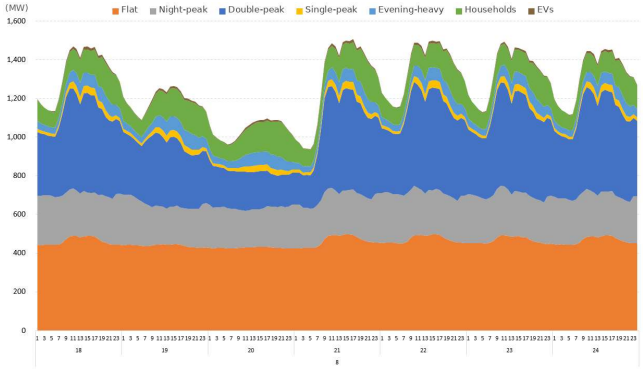
Hourly electricity intensity turns value added into 8,760-hour demand



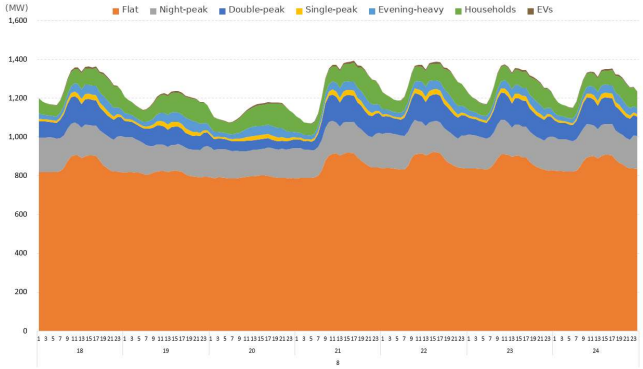
Source: Report Ch. 4.2.3–4.3.2 (pp.39–46), Tables 4-5 & 4-6; KEPCO Power Data Portal; Public Data Portal; KEEI (2025) 2024 Long-Term Energy Outlook

Same 10 TWh, but load shape and required population differ by scenario

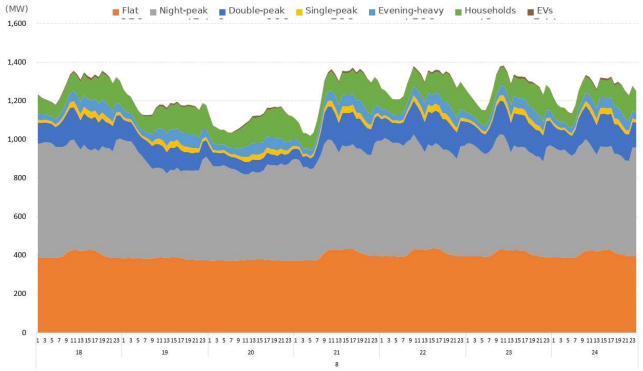
S1 **Double-peak · dips at lunch & weekends**



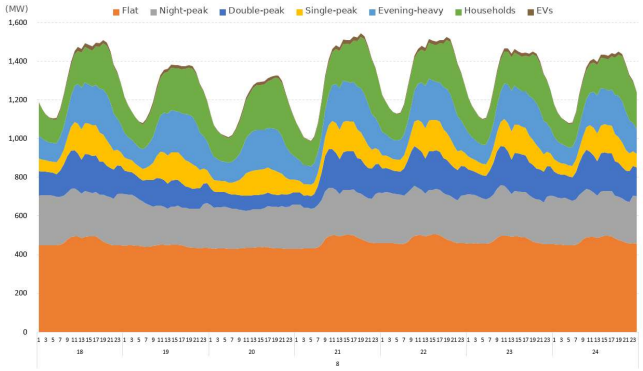
S2 **Flat · steady all day**



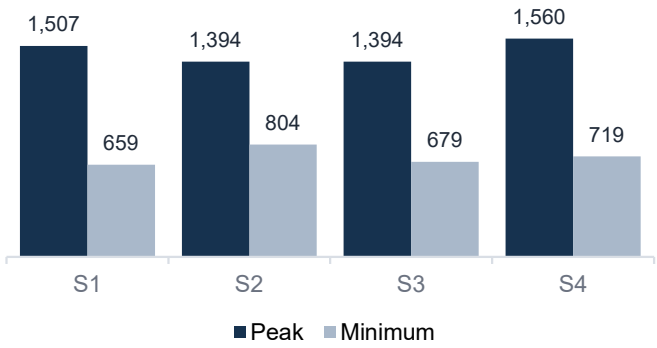
S3 **Night-peak · demand holds at night**



S4 **Single/evening-peak · into the evening**



Peak & minimum load (MW)



Required population

S1	S2	S3	S4
437k	303k	381k	663k

S1·S4 High peak, wide swing (848·841 MW)

S2·S3 Lower peak (S2 swing only 590 MW)

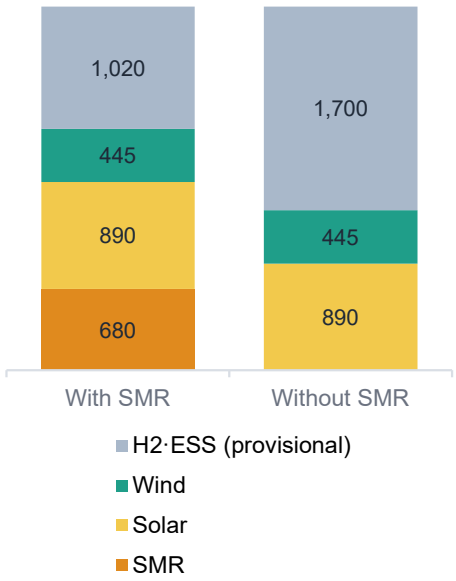
Source: Report Tables 4-7 & 4-8, Figs. 4-6 to 4-9 (pp.47–52) / Charts: sectoral demand in the peak week (Aug 18–24), MW

Generation mix: 11th Basic Plan capacity method scaled to the region

S1 calculation steps

1	**Peak demand**	**1,507** MW	Demand scenario S1
2	**Required (effective)**	**1,838** MW	× (1 + 22% reserve margin)
3	**RE nameplate**	**1,335** MW	44% of total nameplate; solar:wind = 2:1
4	**RE effective**	**138** MW	Capacity credit: solar 14.3%, wind 2.4%
5	**Remainder**	**1,700** MW	(2) − (4) = 1,838 − 138 SMR 680 + H2·ESS balance

S1-Sb nameplate mix (MW)



Resources

- i-SMR 680MW
- Solar
- Wind
- 100% H2
- ESS

Input vs. model-decided

SMR·RE: fixed inputs

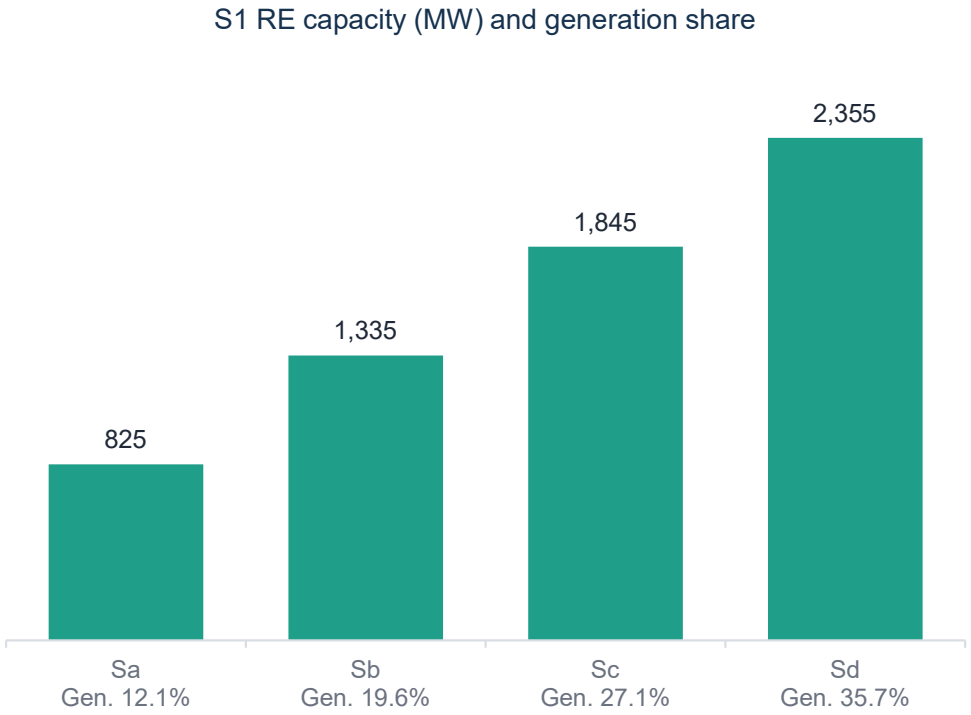
H2·ESS: decided by POSY

e.g., S1-Sa: provisional 1,072 MW → POSY 705 MW

H2·ESS capacity is left free so it can measure how much external supply and flexibility is needed (reserve margin used only to size RE)

Source: Report Ch. 5.1.1 (pp.53–55), Tables 5-2 & 5-5; 11th Basic Plan (MOTIE, 2025b)

Four RE levels built from the gap between capacity (Sb) and generation (Sc) bases



Capacity share: Sa 32.0% · Sb 44.0% · Sc 52.8% · Sd 59.6%

Sb

11th Basic Plan capacity share: 44%

With CFs of 14.6% (solar) and 21.1% (wind), generation share is only 19.6%

Sc

11th Basic Plan generation share: 27.1%

For S1, 510 MW more than Sb

Sa·Sd

Symmetric extension by that gap

Sa = Sb − 510MW, Sd = Sc + 510MW

Reflects uncertainty in future RE deployment

Gap differs by demand: S1 510, S2·S3 610, S4 460 MW

(Same 10 TWh output, so Sc = 1,845 MW in all cases)

Source: Report Ch. 5.1.2 (pp.56–58), Tables 5-3 to 5-5

All costs and fuel prices entered in 2038 prices, the analysis year

SMR

CAPEX (KRW/kW)

6,965,881

Fixed O&M (KRW/kW·mo)

12,441

Lifetime

60 yrs

Fuel cost

3,735 KRW/Gcal

i-SMR target $3,500/kWe

Large-reactor O&M & fuel

Solar

CAPEX (KRW/kW)

693,820

Fixed O&M (KRW/kW·mo)

1,945

Lifetime

20 yrs

Fuel cost

-

BNEF(2025)

2038 projection

Wind

CAPEX (KRW/kW)

465,326

Fixed O&M (KRW/kW·mo)

7,869

Lifetime

20 yrs

Fuel cost

-

BNEF(2025)

Offshore wind as proxy

H_2-fired

CAPEX (KRW/kW)

Gas ×1.2

Fixed O&M (KRW/kW·mo)

Gas ×1.3

Lifetime

30 yrs

Fuel cost (H_2)

3,000 KRW/kg

Retrofitted gas unit

Uplift from prior studies

ESS

CAPEX (KRW/kW)

2,346,000

Fixed O&M (KRW/kW·mo)

4,497

Lifetime

15 yrs

Fuel cost

-

Park (2024)

10th Basic Plan basis

Price basis

Converted to 2038 via PPI; 2.1%/yr after 2025 (2017–2025 avg., excluding the post-COVID spike)

Fuel cost estimate

Nuclear: 2,578 KRW/Gcal (2024) × 2.7%/yr

H2: avg. of 2030/2050 targets; HHV 33,888 kcal/kg

Hydrogen plant cost

CAPEX: gas 1,629,053 KRW/kW × (1 + 21.4%)

O&M: gas 3,623 KRW/kW·mo × (1 + 29.8%)

H_2-fired (100%) CAPEX & O&M Gas-fired costs plus uplifts from prior studies: CAPEX +21.4% (avg. of 3 studies), O&M +29.8% (Ryu et al., 2023)

Source: Report Ch. 5.2 (pp.59–63), Tables 5-6 to 5-9; Freitag et al. (2024); Hernandez & Gençer (2021); KEEI (2021); Ryu et al. (2023)

Plant characteristics entered into POSY as dispatch constraints

SMR (i-SMR)

- 170MW × 4 modules = 680MW
- Load following: 100% ↔ 20% output
- Ramp rate up to 5%/min
- Must-run; full output, no planned outages assumed

KISTEP (2022), 11th Basic Plan

Hydrogen

- Based on existing gas-unit data (expert consultation)
- Representative unit: capacity-weighted net capacity, start-up & no-load cost, min. output, ramp rate
- New units use specs of recent units of similar size

Solar·Wind

- Hourly CF profile × capacity = hourly output
- CFs by source from KPX data (2023)
- Curtailment determined by POSY

KPX; Report Ch. 6.1.1

ESS

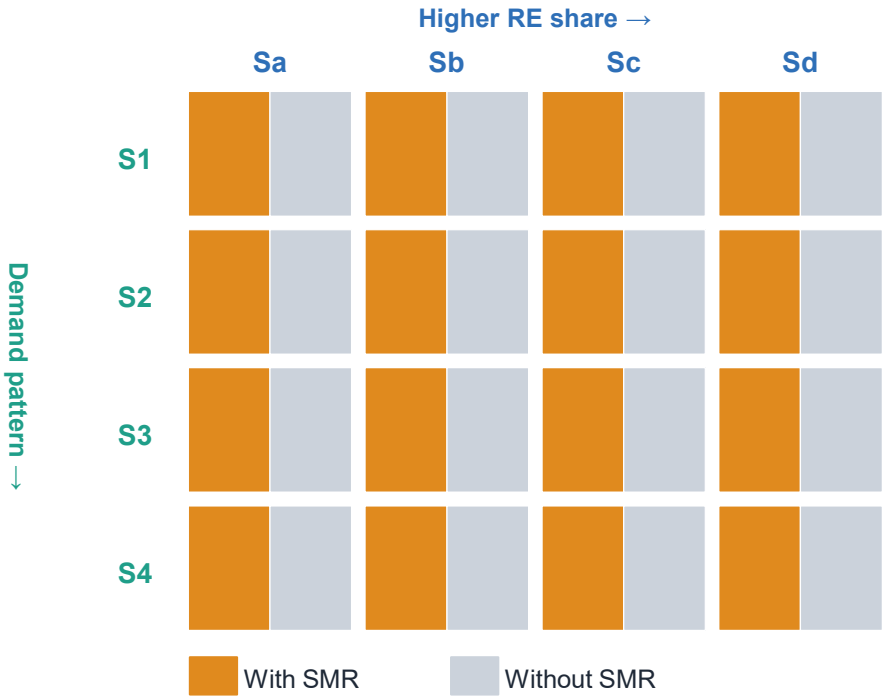
- Capacity optimized by POSY
- Inputs: CAPEX, fixed O&M, 15-yr life
- State-of-charge limits when charging/discharging

Park (2024); Report App. B

These parameters act as min-output, ramping and unit-commitment constraints in POSY and shape hourly dispatch

Source: Report Ch. 6.1.1–6.1.2 (pp.65–68), Ch. 5.1, App. B

4 demand × 4 RE × 2 SMR cases = 32 base scenarios



Demand pattern S1–S4

Fixed: 10 TWh/yr, per-capita income

Varied: industry mix → load shape

Q1) Which demand suits SMRs?

RE level Sa–Sd

Fixed: demand, SMR capacity

Varied: solar & wind capacity

Does more RE change SMR output?

With / without SMR

Fixed: demand, RE capacity

Varied: SMR 680 MW on/off

Q2) How much do SMRs contribute?

Common to all: costs, fuel prices, operating characteristics and model settings. RE capacity is sized to each scenario's peak load (Sc is 1,845 MW in all)

Source: Report Ch. 5 (pp.53–58), Table 5-5, Ch. 6.2.1 (p.68)

Three additional analyses test the scope and robustness of the findings

Further RE expansion

Se – Si

Setup

S1 · with SMR

Beyond Sd: solar +340 MW and

wind +170 MW per step

(Si: solar 3,270 · wind 1,635 MW)

As RE keeps growing, what role for SMRs? Where is the cost minimum?

Pathway comparison

3 pathways

Setup

Sa + SMR: minimal RE, SMR deployed

Sr: no SMR; its output replaced by RE

(solar +3,251 · wind +1,626 MW)

Sf + SMR: both expanded

Are SMRs and renewables substitutes or complements?

Sensitivity

2 variables

Setup

SMR CAPEX doubled

Hydrogen price −50%

Does the conclusion hold under greater cost uncertainty?

※ Run for S1 only, assuming trends differ little across demand scenarios. Sr replacement capacity based on 11th Basic Plan capacity factors

Source: Report Ch. 6.2.2 (pp.73–78), Table 6-6

Where the inputs came from: 10 datasets built into demand and supply DBs

Load patterns — 2023
KEPCO Power Data Portal
→ 8,760 h demand shape

Value added — 2022
BOK Input-Output Tables
→ Intensity, rep. industries

Regional scale — 2023
KEPCO regional sales
→ Basis for 10 TWh/yr

Target income — 2023
World Bank G20
→ $30,000 → population

Households·EVs — 2038
KEPCO, Public Data Portal, KEEI
→ Household & EV demand

Demand input DB: 8,760-hour demand × 4 scenarios

Generation mix — 2038
11th Basic Plan for Electricity
→ SMR & RE capacity

RE generation — 2023
CFs from KPX data
→ RE output

Capital costs — 2038
i-SMR program, BNEF, etc.
→ Fixed costs

Fuel cost — 2038
Past records, H2 plan
→ Variable cost, SMP

Plant characteristics — -
KISTEP, expert input
→ Dispatch constraints

Supply input DB: capacity · costs · fuel · plant specs · RE output profiles

Source: Report Ch. 3.1, Ch. 4, Ch. 5, Ch. 6.1.2 / RE capacity factors from KPX data

Separating externally given values from values set by this study

Given by external data & official plans

- 11th Basic Plan: reserve margin, RE share, capacity credit
- i-SMR capacity and target construction cost
- 2038 population, household, EV & power outlook
- Technology cost outlooks (BNEF) & records (KPX)
- Hydrogen price target (H2 Economy Plan)
- G20 per-capita GDP, municipal demand

Processed or set by this study

Framework

Hypothetical isolated grid, static 2038 analysis, 10 TWh/yr

Demand inputs

62 integrated industries, indexed patterns, representative industries & shares, population scaling, sample correction

Supply & cost inputs

Regional capacity scaling, H2 cost uplift, nuclear fuel trend, PPI 2.1%

Scenarios & model

Sa–Sd, Se–Si; SMR must-run, no outages; LP; negative prices → 0

Translating national-level values into “regional, 2038” inputs is itself the core of this study’s design

Source: Assumptions in Report Ch. 4, 5 and 6.1, classified by origin

POSY finds least-cost hourly dispatch and flexible-capacity investment

INPUT

- Hourly demand (8,760 h)
- RE output profile × RE capacity
- Installed capacity (SMR, RE, etc.)
- Fixed & variable costs
- Plant specs (min. output, ramps)

POSY

Developed by OECD-NEA · open-source, Julia-based

Objective: minimize total cost

Hourly dispatch, supply = demand

New-capacity investment

Min. output, ramp & storage limits

Endogenous curtailment

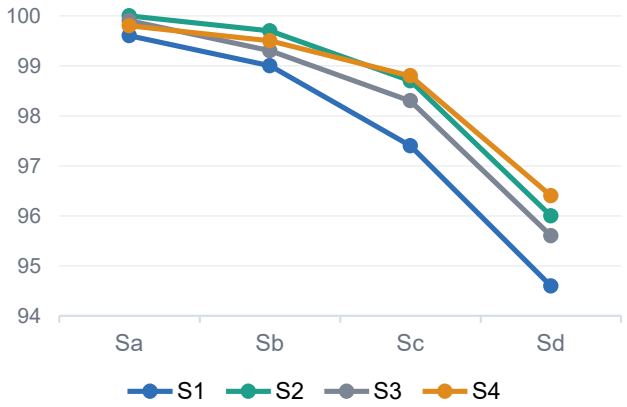
OUTPUT

- Output & CF by source
- Optimal new capacity (hydrogen, ESS)
- Hourly & average SMP
- Total & per-source cost
- Curtailment

Source: Report Ch. 6.1.1 (pp.65–66), App. B (POSY formulation)

With high RE, flat & night-peak demand (S2·S3) gives the lowest SMP and cost

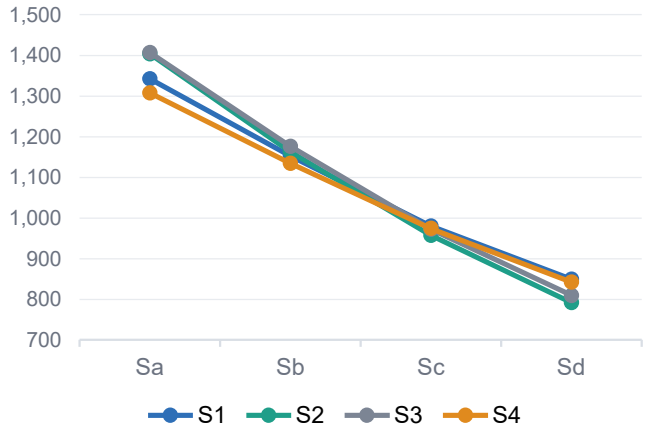
SMR capacity factor (%)



SMP (KRW/kWh)



System cost (KRW bn)



More RE: Sa→Sd More RE output → lower H_2 and SMR capacity factors → less H_2 fuel spending, so SMP and system cost fall (all demand patterns)

Differences by demand pattern (at Sd · all with SMR)

S1 Double-peak

High peak; demand dips at lunch & weekends

Lowest SMR CF (94.6%) · highest cost (KRW 849 bn)

→ Deep duck curve forces SMR to back down; H_2 covers the peaks

S2 Flat · S3 Night-peak

Lower peak; demand holds at night

Lowest SMP & cost (SMP 177–179 KRW/kWh)

→ ESS fills the gentle shortfalls, so H_2 sets the price less often

S4 Single-peak / evening-heavy

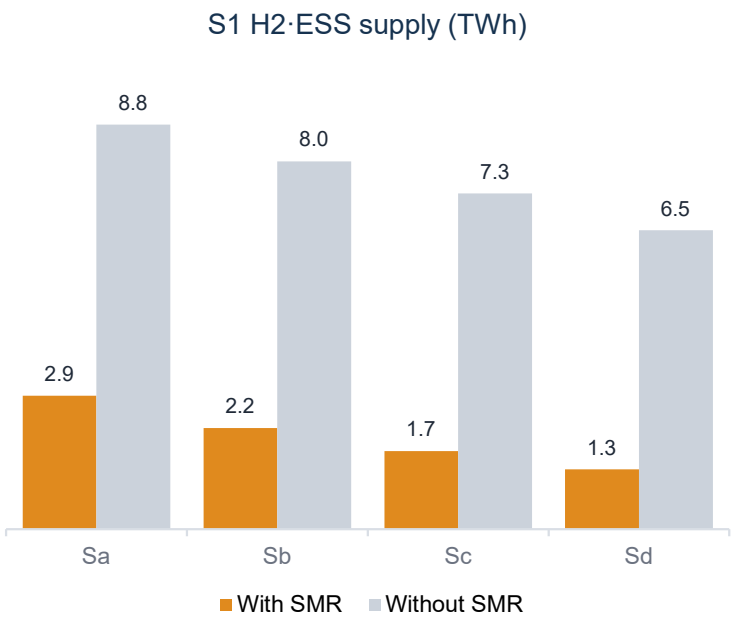
Demand lasts until ~19:00; highest peak

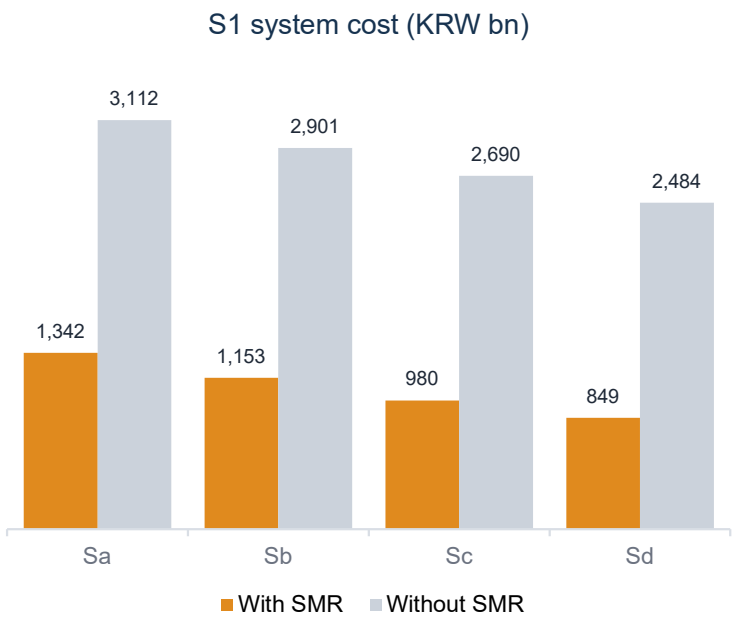
Top SMR CF (96.4%) · top SMP (195 KRW/kWh)

→ Day-to-evening demand keeps SMR running, but H_2 covers the evening peak

Source: Report Tables 6-3 to 6-5, Figs. 6-4 to 6-7, Ch. 6.2.3 (pp.78–81)

With SMRs, H2·ESS supply falls to ~1/3 or less and system cost to under half





1.3–3.1 TWh

H2·ESS supply with SMR

(6.4–9.1 TWh without SMR)

298–301 KRW/kWh

SMP without SMR

Nearly flat even as RE grows

293→191 KRW/kWh

SMP with SMR

Falls as RE expands (S1)

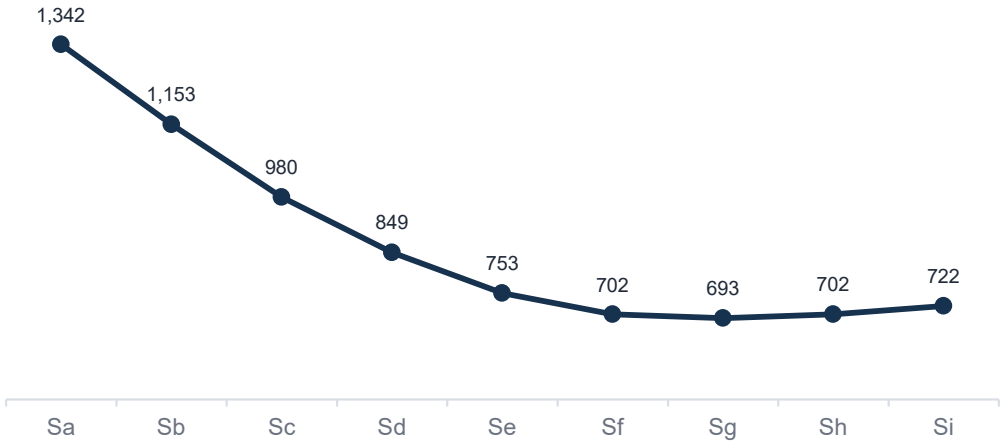
Result With SMRs, H_2·ESS supply and system cost fall sharply in all 4 cases → low-fuel-cost SMRs at high CF replace costly H_2 generation

Design H2·ESS supply proxies the need for outside power → without SMRs, large flexible capacity or imports are unavoidable, at odds with distributed energy

Source: Report Tables 6-1, 6-4, 6-5; Figs. 6-1 & 6-2 (pp.68–73)

Cost bottoms out at Sg as RE grows; SMR + RE together is the best option

S1 · with SMR: system cost (KRW bn)



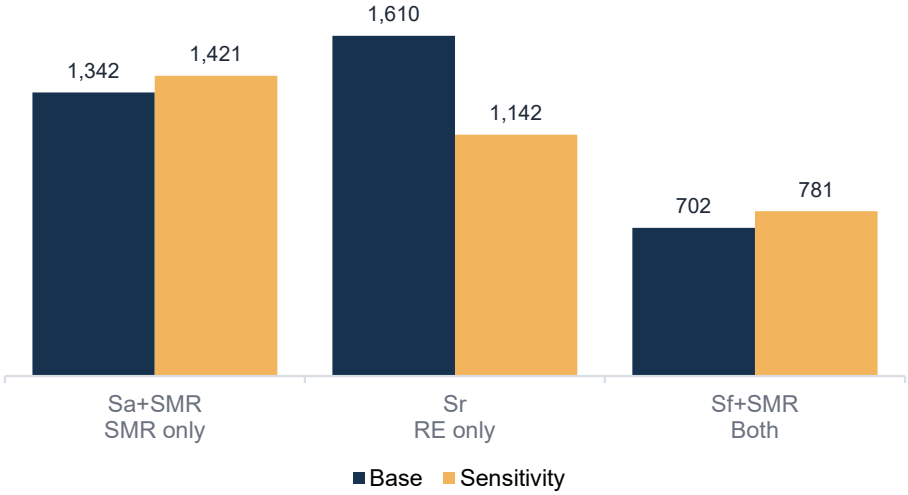
Change, Sd → Si

SMP	Curtailment	SMR CF
191 → 40 KRW/kWh	**0 → 462** GWh	**94.6 → 54.8** %

Inference Beyond Sg little H_2 is left; extra RE just cuts SMR output or is curtailed

→ Considering CFs and curtailment, Se–Sf is the appropriate range

System cost by pathway (KRW bn)



Sensitivity: SMR CAPEX ×2 for Sa+SMR and Sf+SMR; H2 price −50% for Sr

Result

· With only one option, the ranking flips with external factors such as H2 prices (Sr 1,142 < Sa+SMR 1,342)

· SMR + RE together stays lowest even under sensitivity

Source: Report Tables 6-7 to 6-9, Fig. 6-3, Ch. 6.2.2 (pp.73–78)

From input changes to results: simulated facts vs. interpretation

Input change	Operation & capacity	Outcome	Mechanism (inference)
More RE: Sa→Sd With SMR · S1	H2 700→343 MW ESS 5→289 MW	SMP 293→191 KRW/kWh Cost 1,342→849 KRW bn	More zero-cost power to charge ESS → ESS takes over hydrogen's role
Excess RE: Se→Si With SMR · S1	Curtailment 0.5→462 GWh SMR CF 89.6→54.8%	SMP 144→40 KRW/kWh Cost rises again after Sg	More RE does not cut cost indefinitely (negative prices set to 0)
Without SMR All demand cases	ESS capacity 0 Hydrogen covers shortfalls	SMP nearly flat at 298–301 KRW/kWh	SMP set at hydrogen fuel-cost level
Demand pattern At Sd	S2·S3: gradual demand S4: sustained evening demand	S2·S3: lowest SMP S4: highest SMR CF	SMRs follow demand → H2 sets the price less often

Result **Inference** Middle two columns: simulation results; right column: interpretation

Source: Report Tables 6-2 to 6-8, Ch. 6.2 (pp.68–81)

Limitations: a static, hypothetical-grid analysis with data constraints

Framework

A hypothetical isolated grid, not a specific region. With inter-regional exchange, CFs and economics could differ

Static analysis

Population and GRDP fixed; 2023 intensities kept; 2038 simulated with 2023 hourly patterns

Data coverage

Portal data (~484 TWh) cover ~89% of sales → intensities may be underestimated. Usage (2023) and value-added (2022) years differ

Causality

Assumes a one-way link from electricity use to value added

Model & costs

No power-flow modeling; no curtailment compensation. SMR and hydrogen cost uncertainty partly tested by sensitivity

Source: Report Ch. 2.3 (p.14), Ch. 4.1.2 (p.34), Ch. 6.1.1 (p.66) & fn. 25, Ch. 7.3 (pp.87–88)

A self-built input DB and scenarios quantify SMRs' role as distributed energy

What we analyzed

Simulated hourly dispatch and investment with POSY for 32 base and additional scenarios in a hypothetical isolated grid (2038, 10 TWh/yr)

With what data

KEPCO 8,760 h × I-O Tables → 64 sector patterns → 4 demand series

11th Basic Plan & literature → generation mix and 2038 costs

With what design

Demand 4 × RE 4 × SMR 2; further RE expansion (Se–Si); 3 pathways; 2 sensitivities

What we found

A1) With more RE, SMRs suit flat & night-peak demand best; long evening demand also keeps CFs high

A2) SMRs complement RE: far less flexible capacity and cost; SMR + RE stays least-cost under sensitivity

Policy implications

- Recognize SMR–RE complementarity
- Establish SMRs as distributed energy, with a benefit framework
- Introduce regional SMR power purchase agreements (PPAs)

Source: Report Ch. 7 (pp.83–87)