An analysis of centralized procurement mechanisms for clean attributes in PJM

Emmanuele Bobbio
Sr. Lead Economist
Advanced Analytics
28 March 2023

Disclaimer

- These slides discuss results of analysis performed by PJM in response to CPAWG's request, subsequent requests from the IMM, Wilson Energy Economics, Constellation, and feedback from stakeholders
- Results depend on assumptions and modeling approach
- Results are not forecasts
- This study is complementary to the "Energy Transition in PJM: Resource Retirements, Replacements & Risks" study but targets different questions:
  - This study: *equilibrium* modeling of alternative clean attribute market designs' impacts on retirement and investment decisions; deliberately abstracts from present issues like interconnection bottlenecks
  - "RRRR" study: *balance-sheet* approach to retirements, and activations, seeking to identify potential near-term resource adequacy risks that may arise absent enhanced market signals under discussion at RASTF and CAPSTF

Design elements discussed and analyzed in CAPSTF

Procurement mechanism

- Sequential, clean attribute first (FCEM+RPM)

Clean attribute → Capacity

- Sequential, capacity first (RPM+FCEM)

Capacity → Clean attribute

- Integrated, clean energy (ICCM)

Co-optimize clean energy and capacity

- Integrated, clean capacity (RPM+)

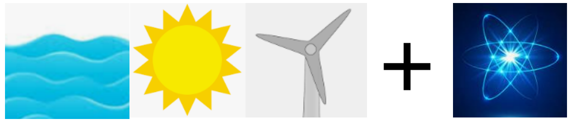
Co-optimize clean capacity and capacity

Product definition

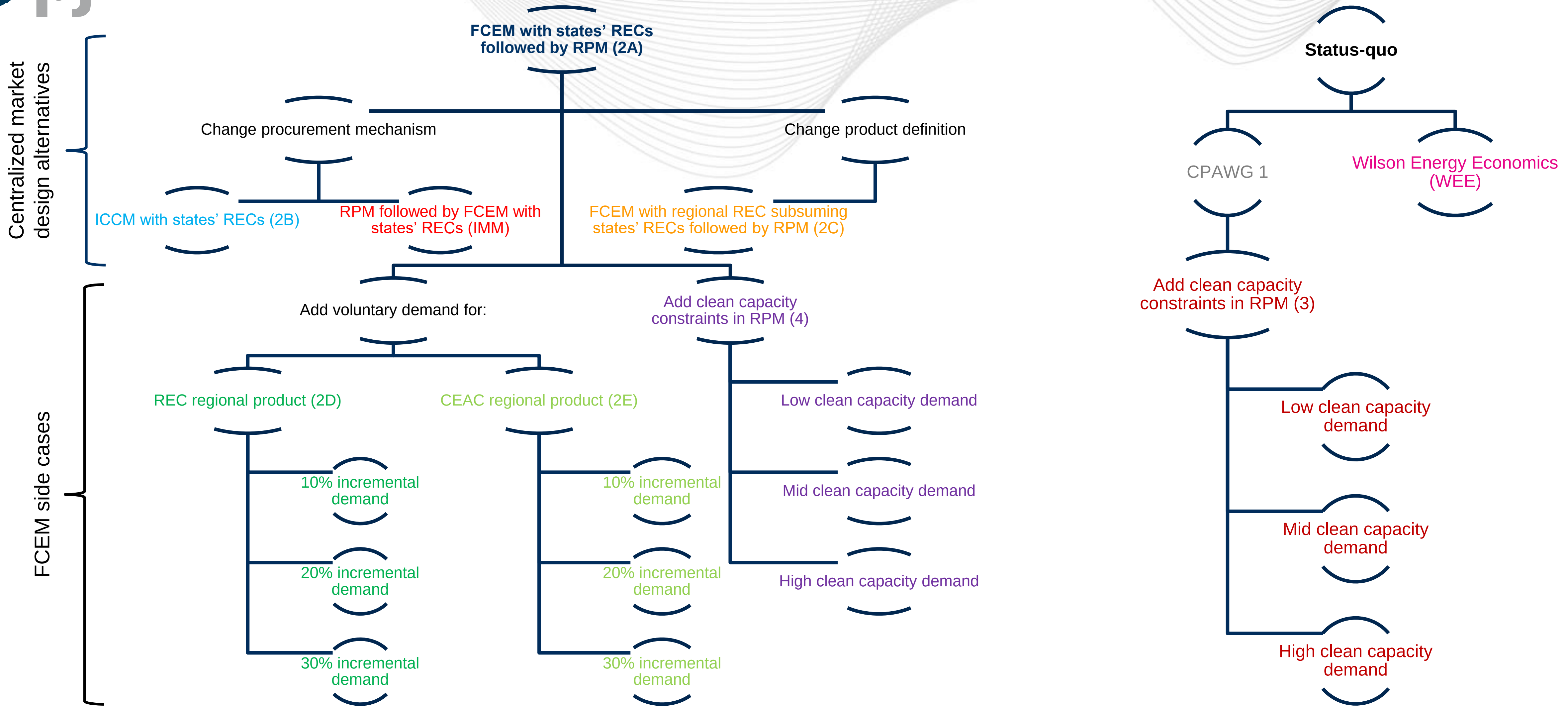
- State-specific RECs

- Regional REC

- Regional clean credit (nuclear eligible)



Scenarios' map (see next slide for scenario description)



Case ids in parenthesis, corresponding to CPAWG's request numbering for that request; **FCEM** is Forward Clean Energy Market; **ICCM** is Integrated Clean and Capacity Market; **CEAC** is Clean Energy Attribute Certificate (includes nuclear); **Wilson Energy Economics**, consultant to the consumer advocate offices in NJ, PA, MD, DC, and DE

Scenarios' description and figures' labels

- FCEM with states' RECs followed by RPM (2A): Forward Clean Energy Market (FCEM) with states' specific RECs followed by capacity market (RPM); short label used in figures **(2A) FCEM, states RECs**
- ICCM with states' RECs (2B): single Integrated Clean energy and Capacity Market for the two product types; label in figures **(2B) ICCM, states RECs**
- RPM followed by FCEM with states' RECs (IMM): as 2A but invert the ordering of FCEM and RPM; short label **(IMM) RPM followed by FCEM**
- FCEM with regional REC subsuming states' RECs followed by RPM (2C): as 2A but with a common regional REC replacing state-specific RECs; short label **(2C) FCEM, regional REC**
- Add voluntary demand for the regional REC (2D): same as 2A but with added 10%, 20%, 30% voluntary REC demand with 5% slope; details in slide below; short label **(2D) FCEM, X% voluntary REC**
- Add voluntary demand for the regional REC (2E): same as 2D but the voluntary demand is for a regional clean product (includes nuclear); details in slide below; short label **(2E) FCEM, X% voluntary CEAC**
- Add clean capacity constraints in RPM (4): same as 2A but with added clean capacity constraints (low, mid, high) for NJ, MD, DE, DC, VA, PA, IL; details in slide below; short label **(4) FCEM, low/mid/high clean capacity**
- Status quo, CPAWG and Wilson Energy Economics: as 2A but the fixed cost in sellers' forward market offers is multiplied by 1.05 in CPAWG's case and 0.95 in WEE's case; short labels **(CPAWG 1) Status Quo** and **(WEE) Status Quo**
- Status quo with added clean capacity constraints in RPM (3): same as (1) but with added clean capacity constraints defined as in (4); label **(3) Status Quo, low/mid/high clean capacity**

Analytical framework

Run forward markets for delivery year 2023

For example, run Forward Clean Energy Market with state-specific products followed by capacity market

Outcomes: **Entries and Exits**, Capacity and clean attributes' prices and quantities

Run spot energy market 2023

Outcomes: LMPs, generation, shortages, curtailments, congestions, production costs, resources' revenues and profits, load payments, emissions

Form expectations for delivery year 2024

Run energy market for 2024 (2024 load, fuel prices, technologies) given resources that cleared in capacity auction for DY 2023; update ELCC

Outcomes: E&AS offsets, renewables capacity factors, ELCC

Repeat through 2030

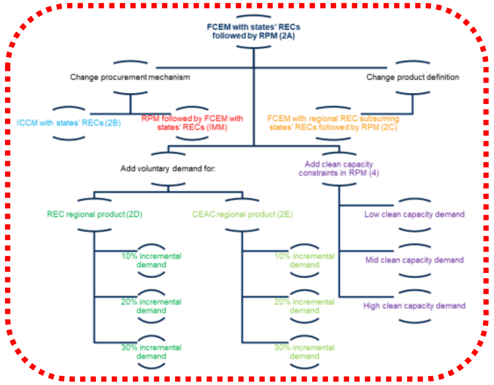
- See appendix for detailed assumptions
- All model inputs and outputs are posted on the CAPSTF's webpage under *Modeling Results*

Key findings

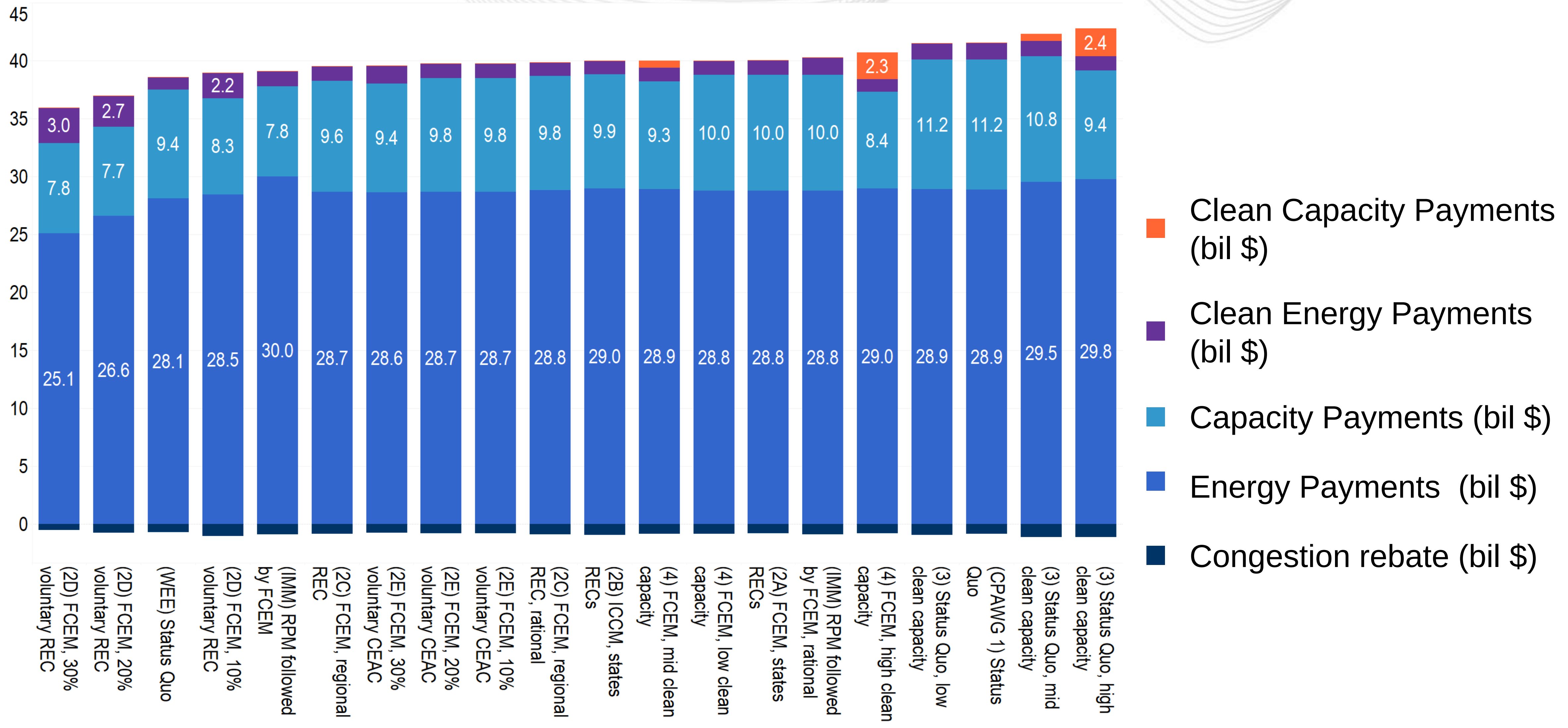
- With fairly accurate forward prices expectations, centralized market design alternatives deliver similar outcomes (ICCM, FCEM+RPM, RPM+FCEM); states' policy coordination on a common product also has limited impacts (regional vs. state-specific RECs)
- Clean capacity constraints, if sufficiently high enough to bind:
  - Accelerate the entry of renewables
  - Alter investments across technologies and locations
  - Increase load costs for states expressing these targets; but,
  - Decrease capacity costs for states without these targets
- Voluntary demand for clean attributes:
  - Accelerates the entry of renewables
  - And *lowers* costs for PJM load

Scenarios comparison, summary:

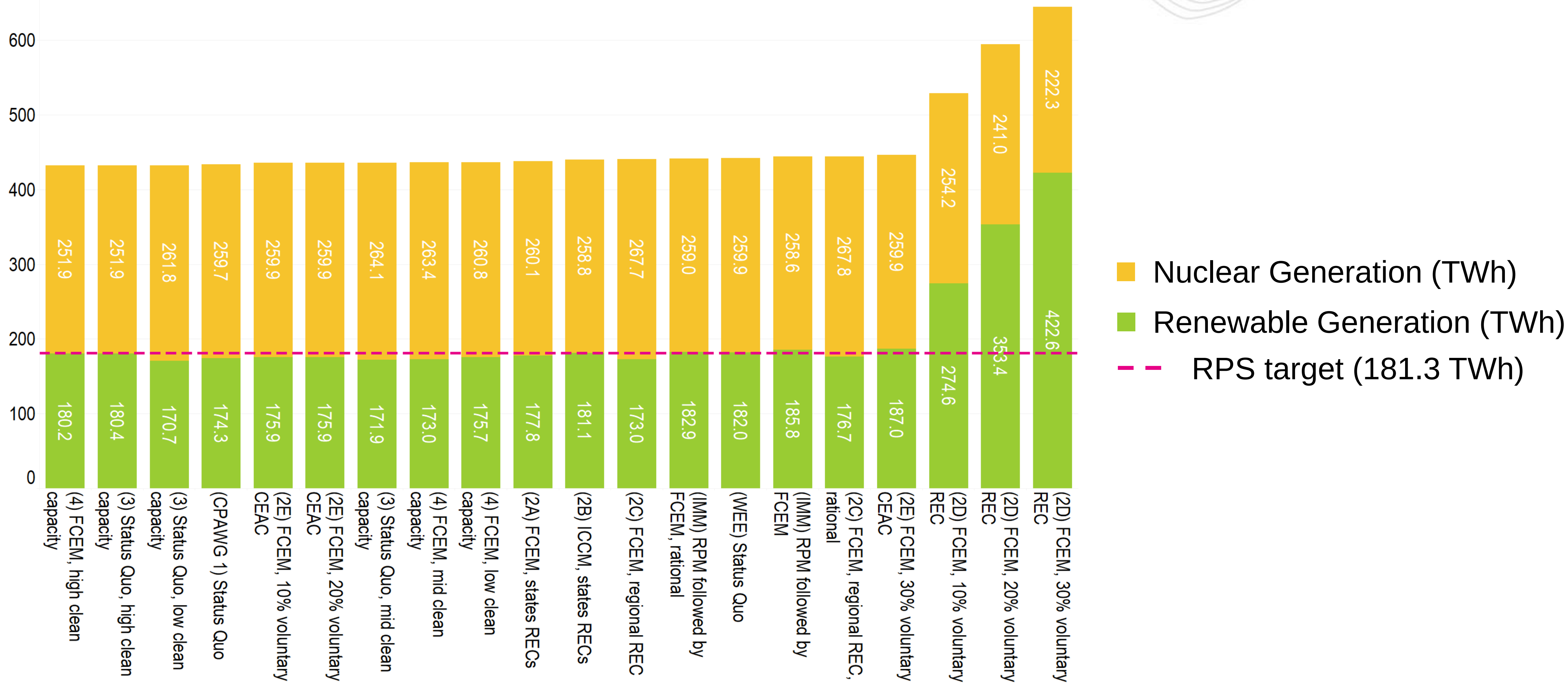
- Load costs
- Clean energy
- Emissions
- System costs



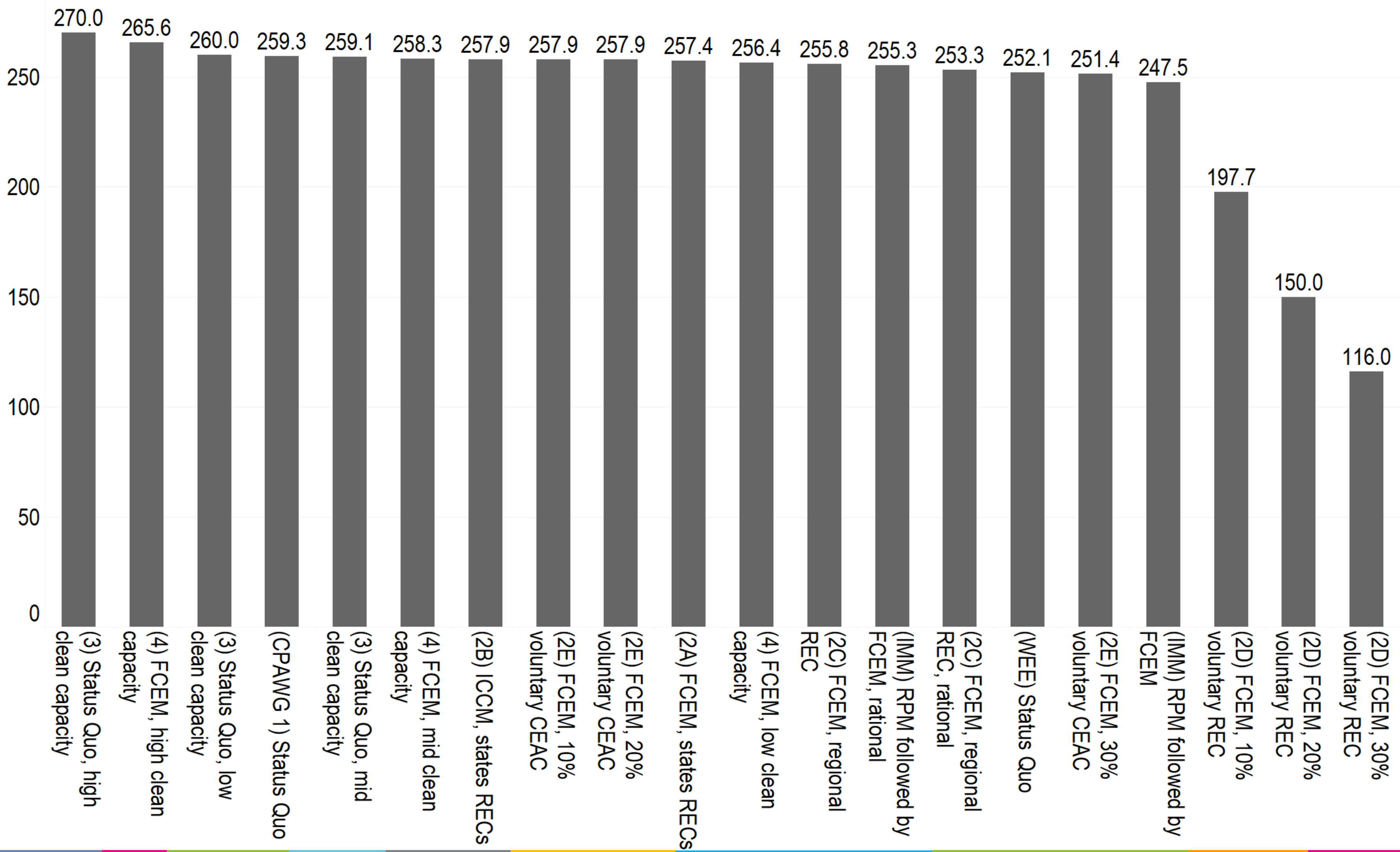
Load costs (2023-2030 average; bil $)



Renewable and nuclear generation (2030 levels; TWh)

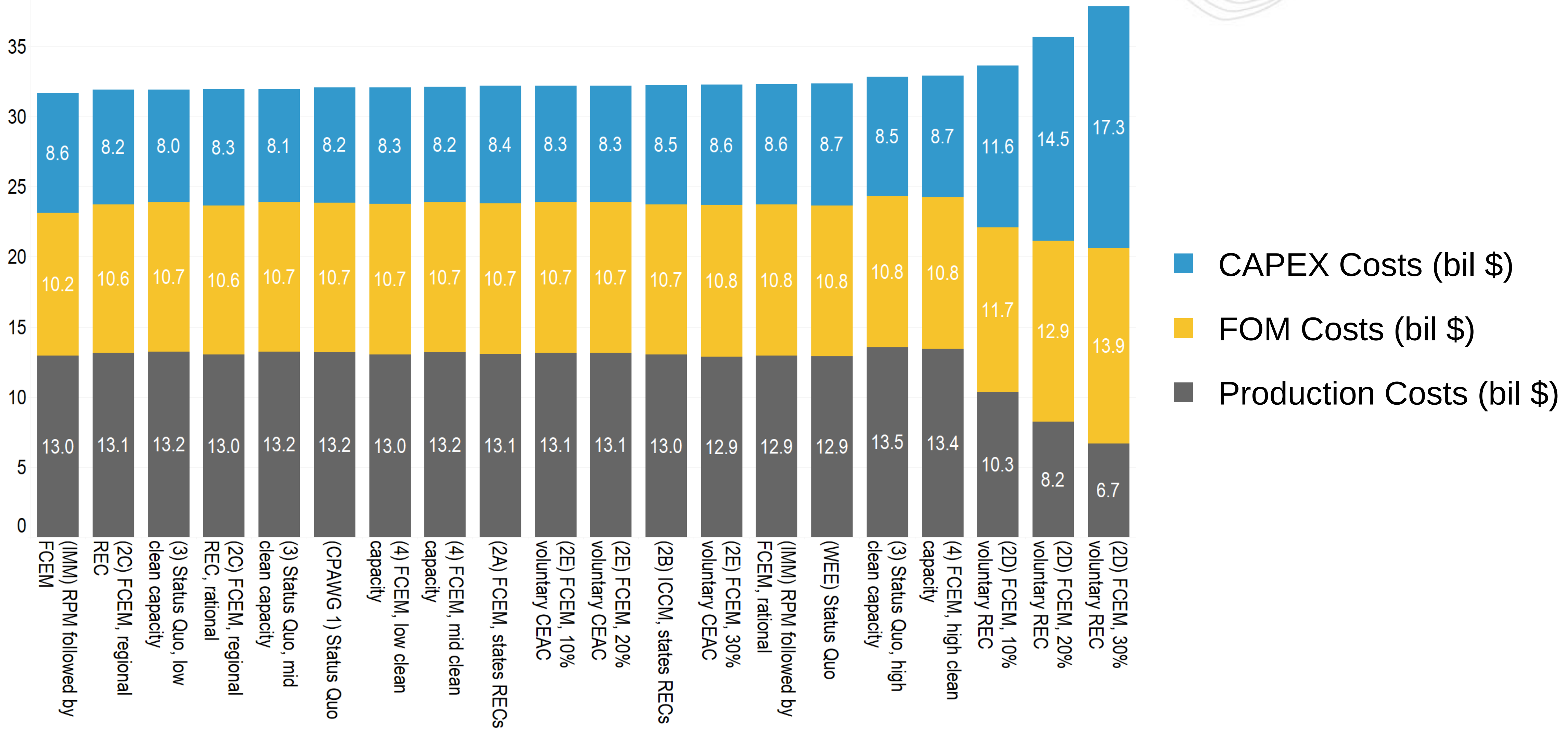


CO2 Emissions in 2030 by scenario (mil. ton)



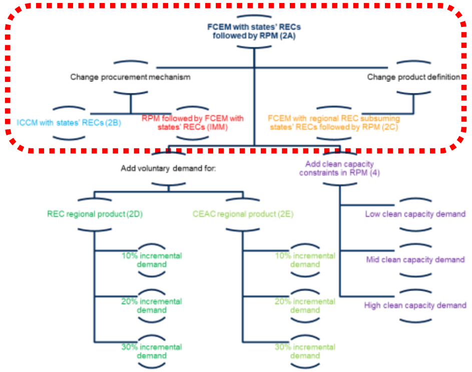
Note: 2023 level in FCEM, states' RECs is 337.2

System costs in 2030 (bil $)



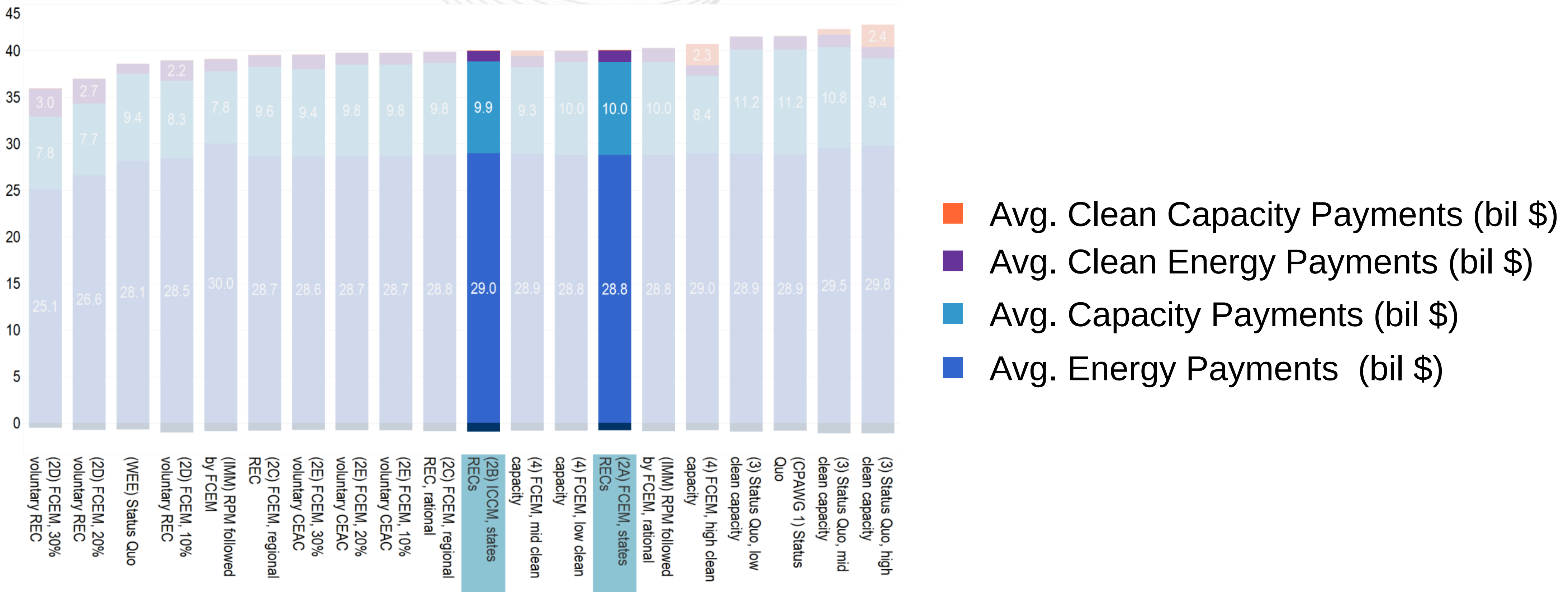
Fundamental market design alternatives:

- Procurement mechanism
- Product definition



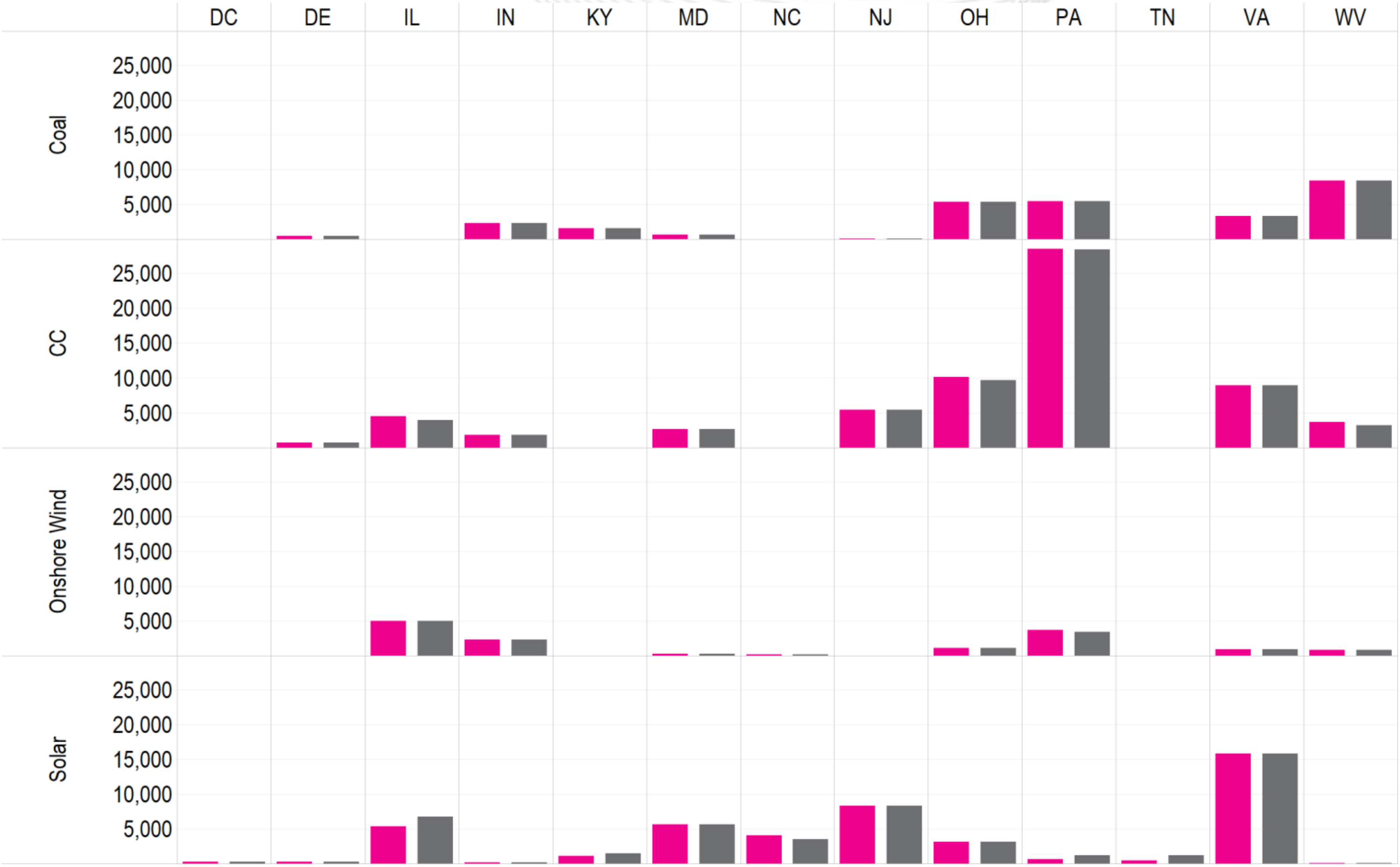
ICCM and FCEM with states' RECs deliver similar outcomes

Load payments (average 2023-2030, gross of congestion; bil $)



- Exits are mainly determined by policy retirements
- States' RPS policies and Transmission capacity limit the location choice of new investments

MW-ICAP across states and selected technologies in 2030



(2A) FCEM, states RECs

(2B) ICCM, states RECs

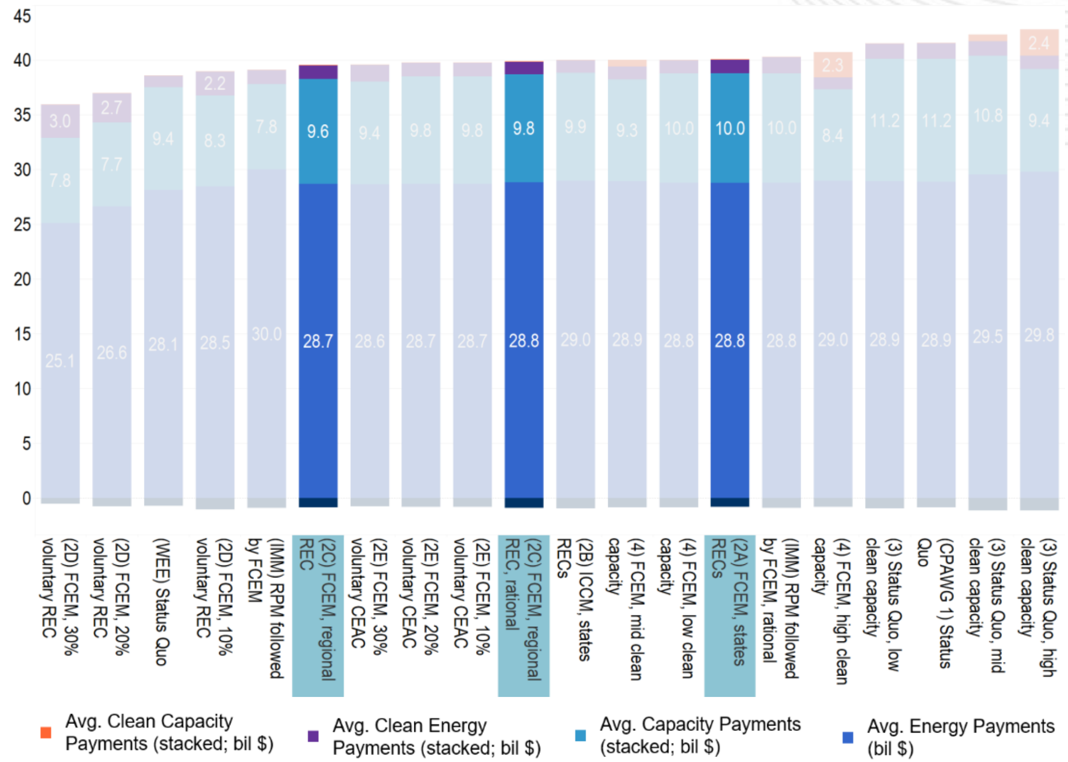
- Buildout broadly unaffected

Policy coordination on a common regional product shifts some solar investment from northern to southern states (2030)

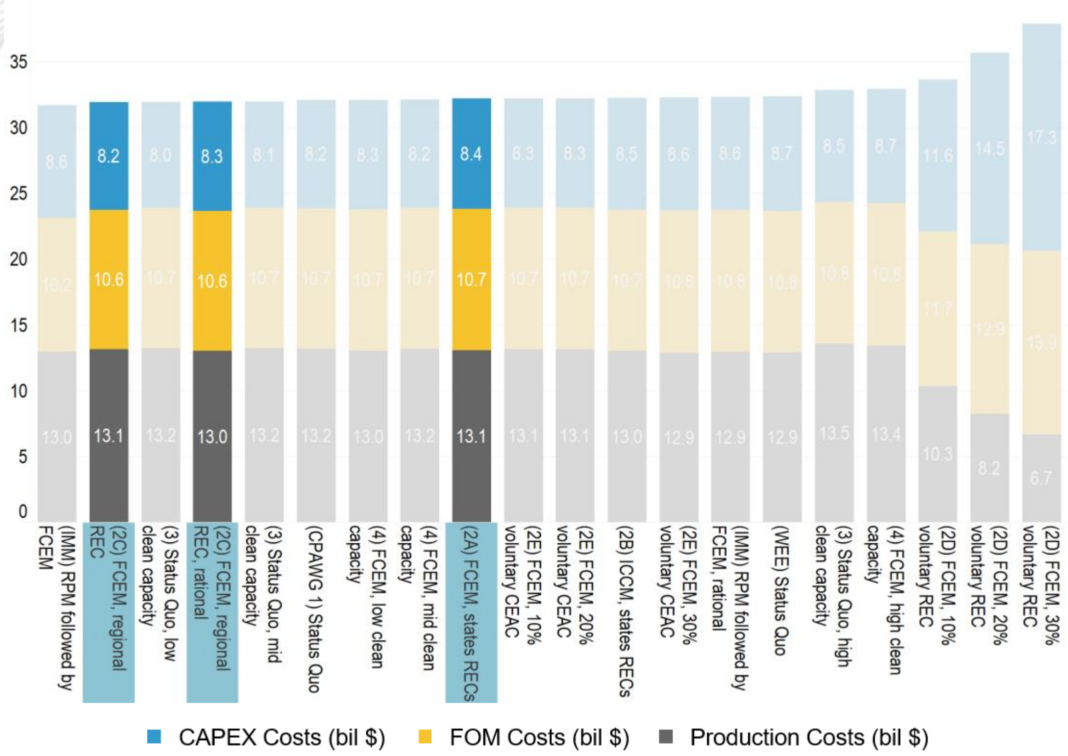
- But changes are overall small, because of reasons in previous slides
- And because states' RPS broadly aligned with economics: carve-outs are for solar, which has lower levelized cost of energy due to IRA, except in Illinois where wind potential is relatively high

Small efficiency gains and load cost impacts from policy coordination, with accurate forward price expectations

Load payments (average 2023-2030; bil $)



System costs in 2030 (bil $)

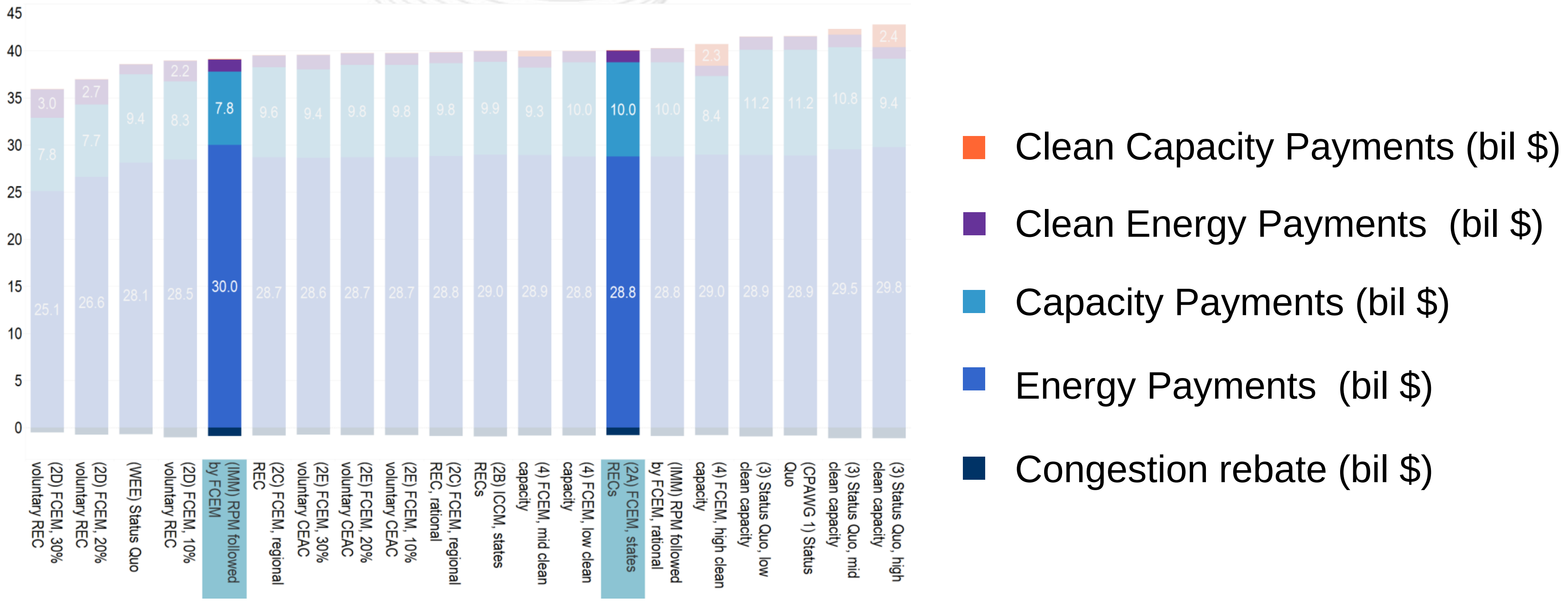


- Reduction of about 100 mil per year in system costs
- Load cost impact mainly depends on forward price expectation formation rule:
    - Load cost essentially the same as with states products if expectations are accurate*

* Near-rational forward price expectations are created by solving for prices using the ICCM engine

Inverting the ordering of the FCEM and RPM lower load costs with incorrect expectations

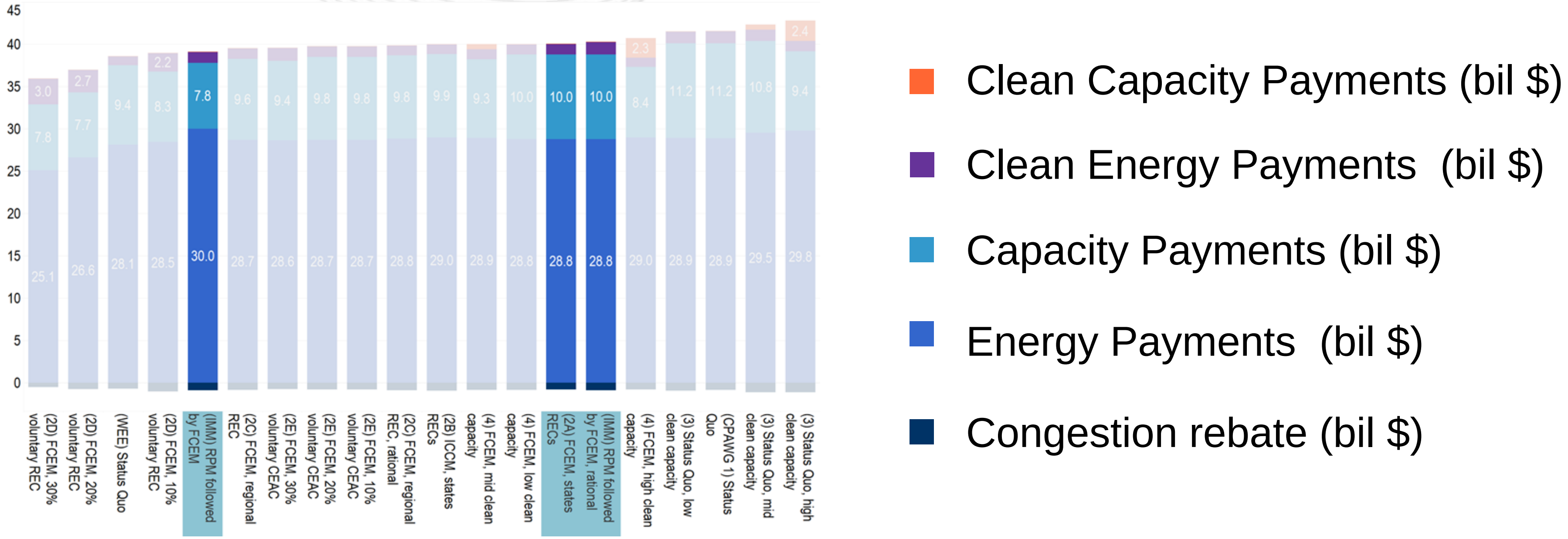
Load payments (average 2023-2030; bil $)



- Resources do not anticipate REC price drop (due to the IRA and renewables' technical improvements)
- Since resources expect past high REC prices to continue, they bid lower in the capacity market, reducing capacity prices and load costs relative to the *FCEM, states' RECs (2A)* and *ICCM, states' RECs (2B)* cases

With accurate expectations for forward prices, load costs in the *(IMM) RPM followed by FCEM* and *(2A) FCEM, states' RECs* cases are similar

Load payments (average 2023-2030; bil $)

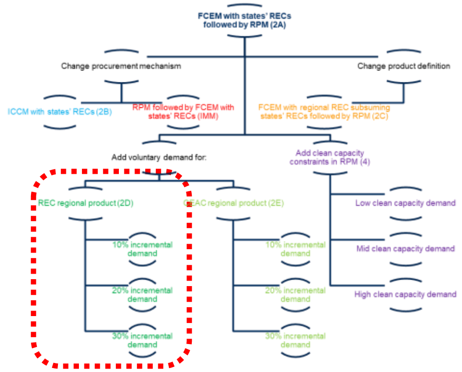


- Load costs can be slightly higher
- Capacity market's tie-breaking does not internalize states' RECs constraints in downstream FCEM, resulting in higher REC prices
- **Example**:
    - Rational expectation* REC price equates forward revenue need of marginal CC (for capacity) and marginal solar (for REC);
    - The capacity market tie-breaking rule happens to select the CC resource;
    - The FCEM still needs to procure the solar resource paying entire forward revenue need (the solar resource does not receive capacity payments), raising REC prices and procurement costs

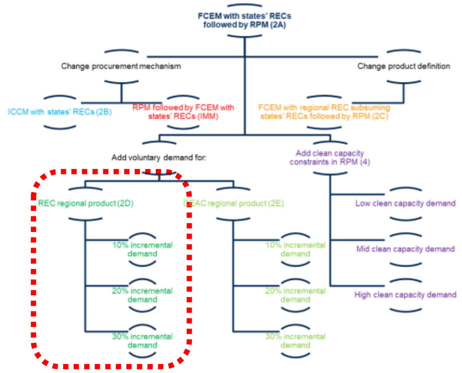
* Near-rational forward price expectations are created by solving for prices using the ICCM engine

FCEM side cases:

- Incremental voluntary demand for a regional REC
- Incremental voluntary demand for a regional CEAC
- Clean capacity constraints



Incremental voluntary demand for a regional *REC*



Voluntary demand modeling

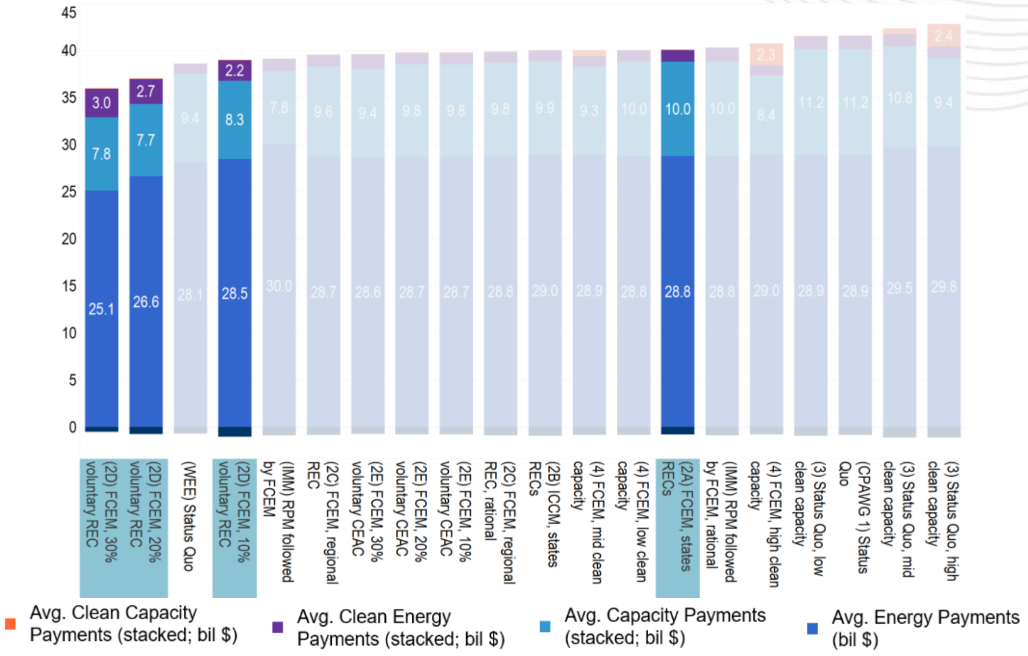
- CPAWG's request cases 2D and 2E are *what-if* sensitivities relative to the FCEM with states' RECs:

What if the introduction of the FCEM allowed more entities to express their preferences for clean attribute products?

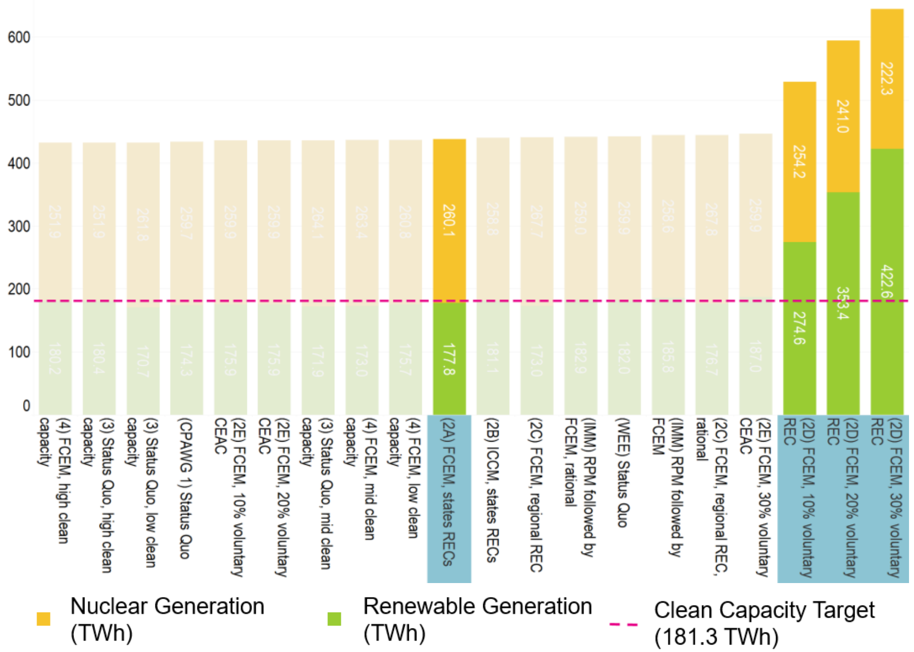
  - The FCEM is voluntary
  - Buyers can procure clean attributes as today; some buyers today may not be able/chose not to express their preference for clean attributes given existing trading venues
  - A centralized, open access, transparent, liquid, and competitive market for a standardized regional clean product could allow some of that unexpressed demand to emerge
- Voluntary demand in these sensitivities is incremental relative to some baseline level normalized to zero for simplicity
- Six sensitivities:
  - Incremental 10%, 20%, or 30% voluntary demand (as fraction of annual load)
  - Two standardized regional product option, renewable (2D) or clean (2E; includes nuclear)
- Voluntary demand slope +/- 5% (as fraction of annual load) with cap at $60/MWh

Voluntary demand for the regional REC product lowers load costs and accelerates the energy transition

Load payments (average 2023-2030; bil $)



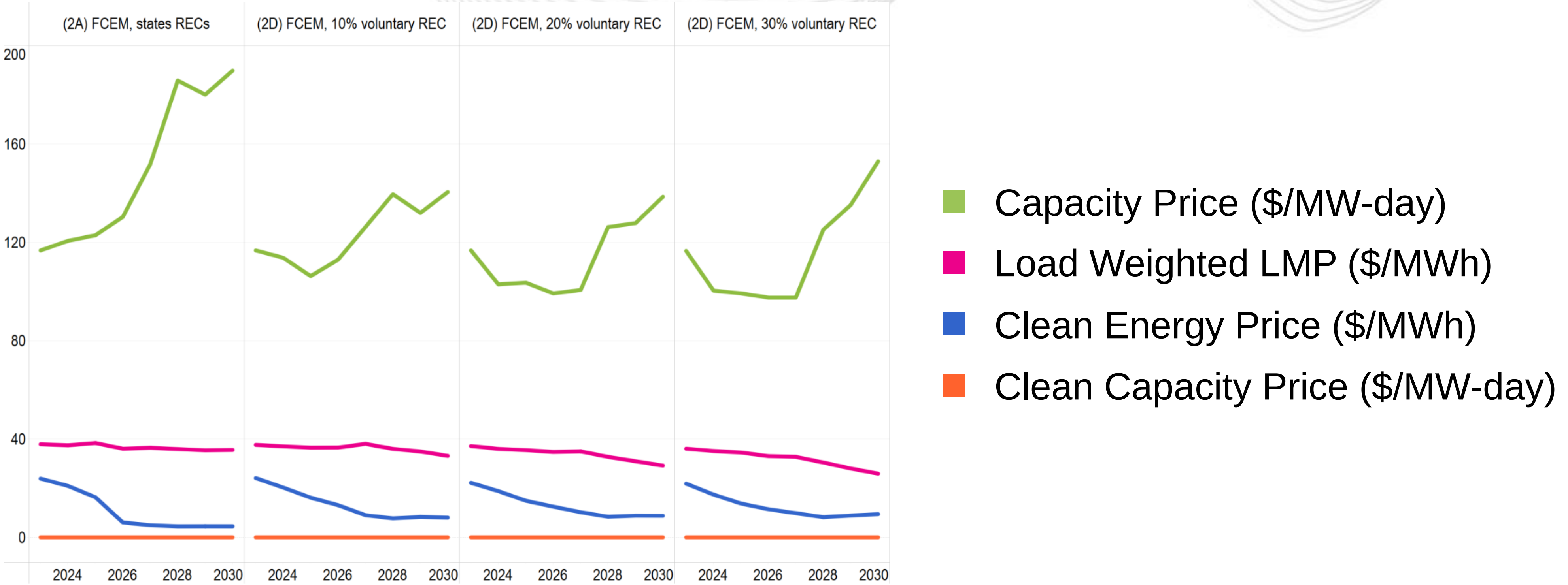
2030 clean generation (TWh)



Note: modeled voluntary demand is incremental reflecting the hypothesis that a transparent, equal access, centralized market allows more voluntary demand to emerge and be expressed

- Voluntary demand increases the REC price
- PJM load pays more for RECs
- *But PJM load pays less for energy and capacity*

Price dynamics: unpacking voluntary participation effects

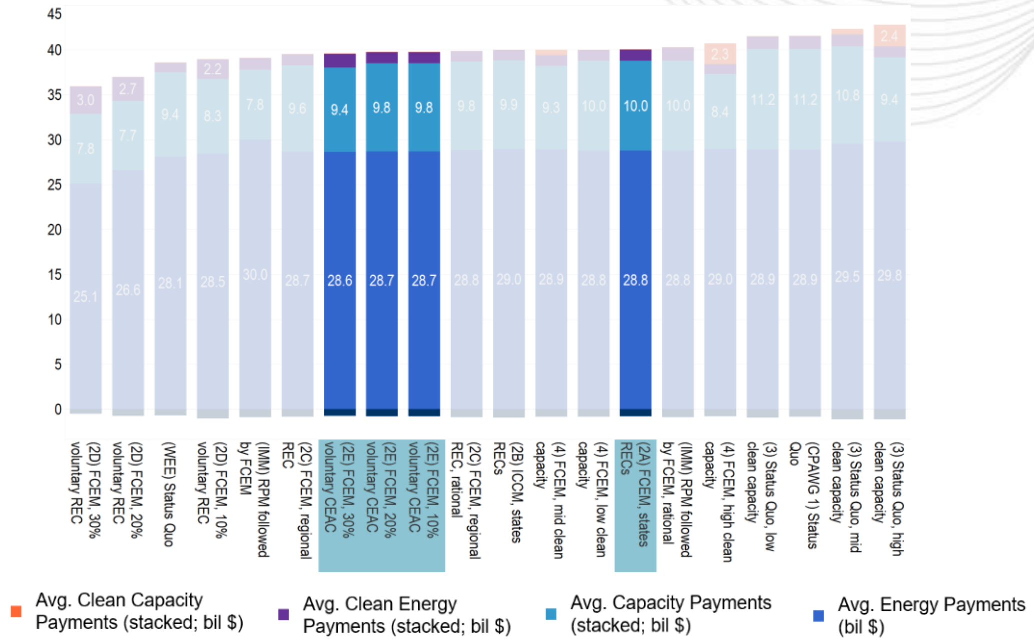


- Voluntary demand payments lower additional capacity revenue needs of new renewable resources, and therefore capacity prices, *ceteris paribus*
- Higher renewable penetration lowers the energy price (displaces also some nuclear generation)
- Lower energy prices may result in lower E&AS and therefore higher capacity and REC prices in later years, the higher the voluntary demand

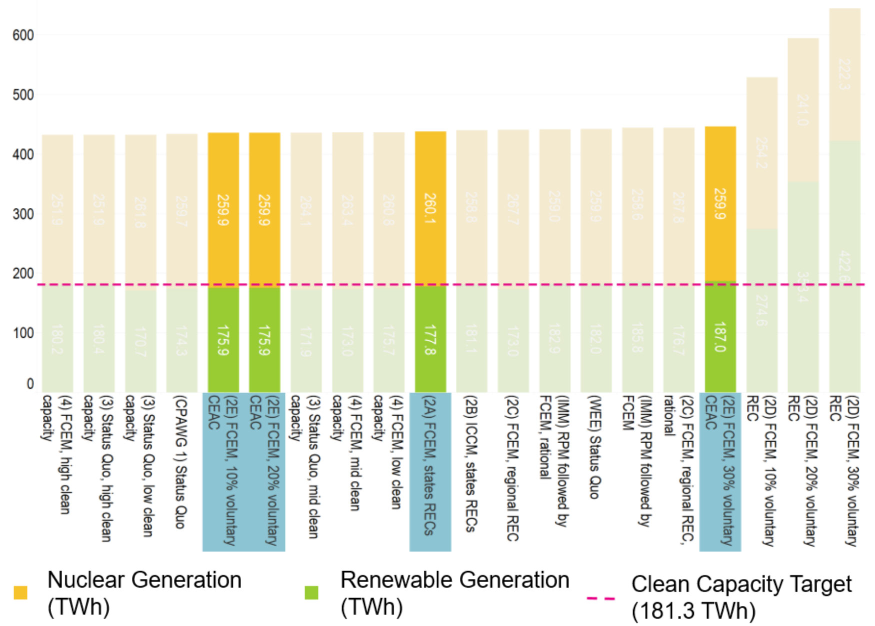
Incremental voluntary demand for a regional *CEAC*

Effects of adding voluntary demand for a regional CEAC

Load payments (average 2023-2030; bil $)



2030 clean generation (TWh)



- PJM has about 30% nuclear generation
- 10% or 20% CEAC voluntary demand: existing nuclear is sufficient (CEAC price=0, results unaffected)
- 30% voluntary demand: additional renewable generation is built, CEAC price greater than zero
  - voluntary demand has ± 5% slope; CEAC is cheap, the market procures above RPS target

Note: we remove NJ nuclear support. NJ is the only state with nuclear subsidies in the model; these subsidies are assumed to renew automatically through 2030

Clean capacity constraints

Clean capacity targets construction methodology

- State/zone clean capacity demand levels for NJ, MD, DE, DC, VA, PA:
  - Low: renewable and clean capacity (UCAP) built at each state/zone location and year in the *FCEM, states' RECs* simulation (CPAWG's case 2A)
  - High: RPS x Peak Load for each state/zone location and year plus 2022 renewable and nuclear capacity (UCAP) at each state/zone location
  - Mid: 0.5 Low + 0.5 High
- These demands are aggregated at the LDA level
- The clean capacity target for each LDA is:

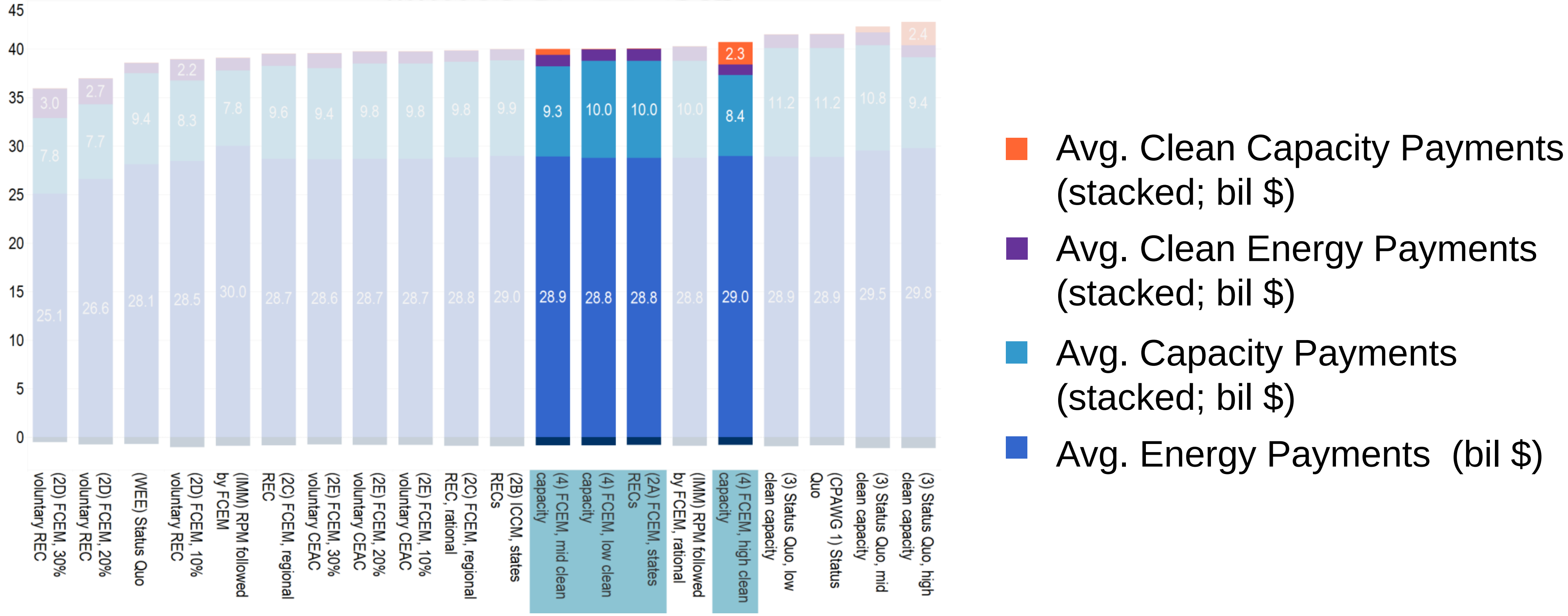
  Target x (1 + Forecast Pool Requirement) – CETL, with FPR = 0.0901
- CETL levels as for generic capacity and based on Energy Exemplar's Eastern Interconnection dataset zonal transmission topology
- Costs are allocated as detailed in the slide *Forward Products' Costs Allocation* below
- Illinois: the target increases uniformly (percentage point-wise) from the existing renewable plus nuclear levels in ComEd and MISO 4 (separately) to 65%/1.0901, 85%/1.0901, and 109.01%/1.0901 in the low, mid, and high cases respectively

Comparison with 28 February 2023 clean capacity targets

- The new targets are generally much lower than those used for the February's simulations
- The February's target definition included DR, batteries, and pump-storage and clean capacity in OH, WV, IN, KY, TN, NC, MI
- The new low targets never bind
- The mid and high targets bind only for Illinois (ComEd, MISO 4)
- February's findings are qualitatively unchanged, but quantitatively much attenuated
- Results for the higher February's targets are on the CAPSTF webpage and discussed in February's analysis update

Clean capacity targets raise load costs and clean generation

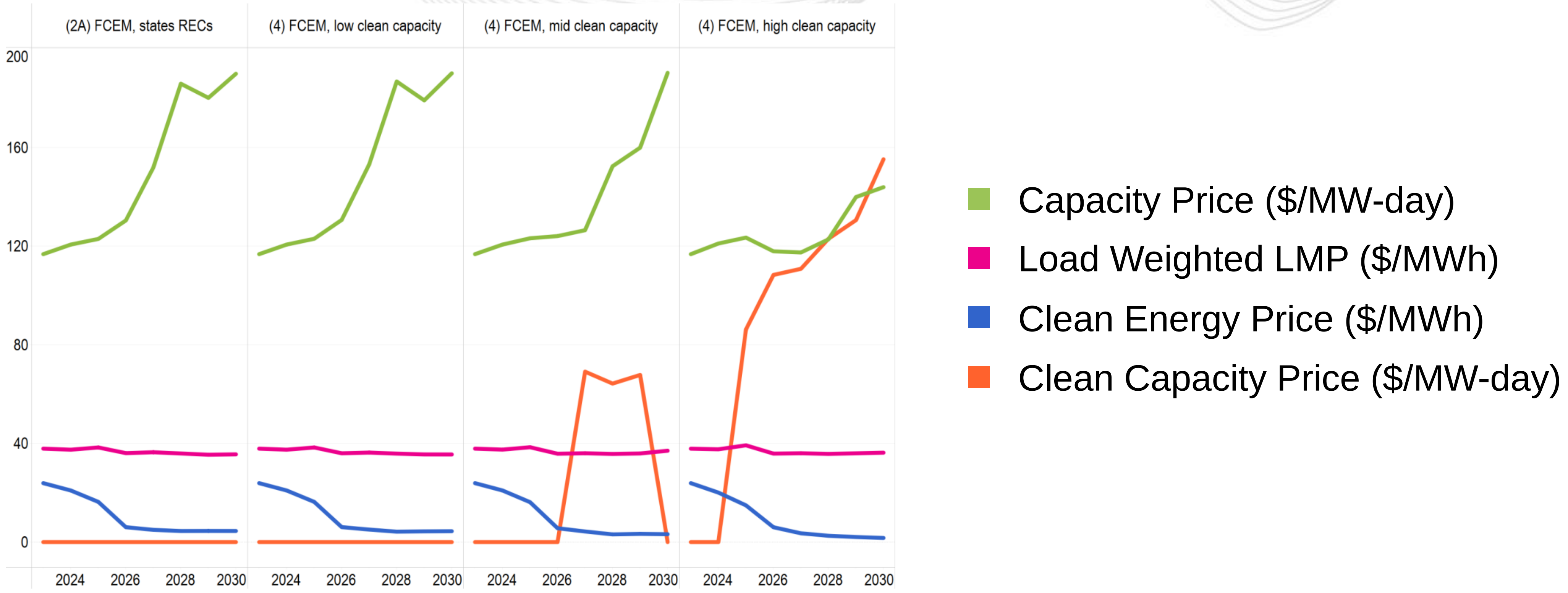
Load payments (average 2023-2030; bil $)



- Clean capacity targets can be met via imports (subject to same LDA structure and CETL as for capacity)
- Clean capacity costs are allocated only to states demanding clean capacity, as detailed below

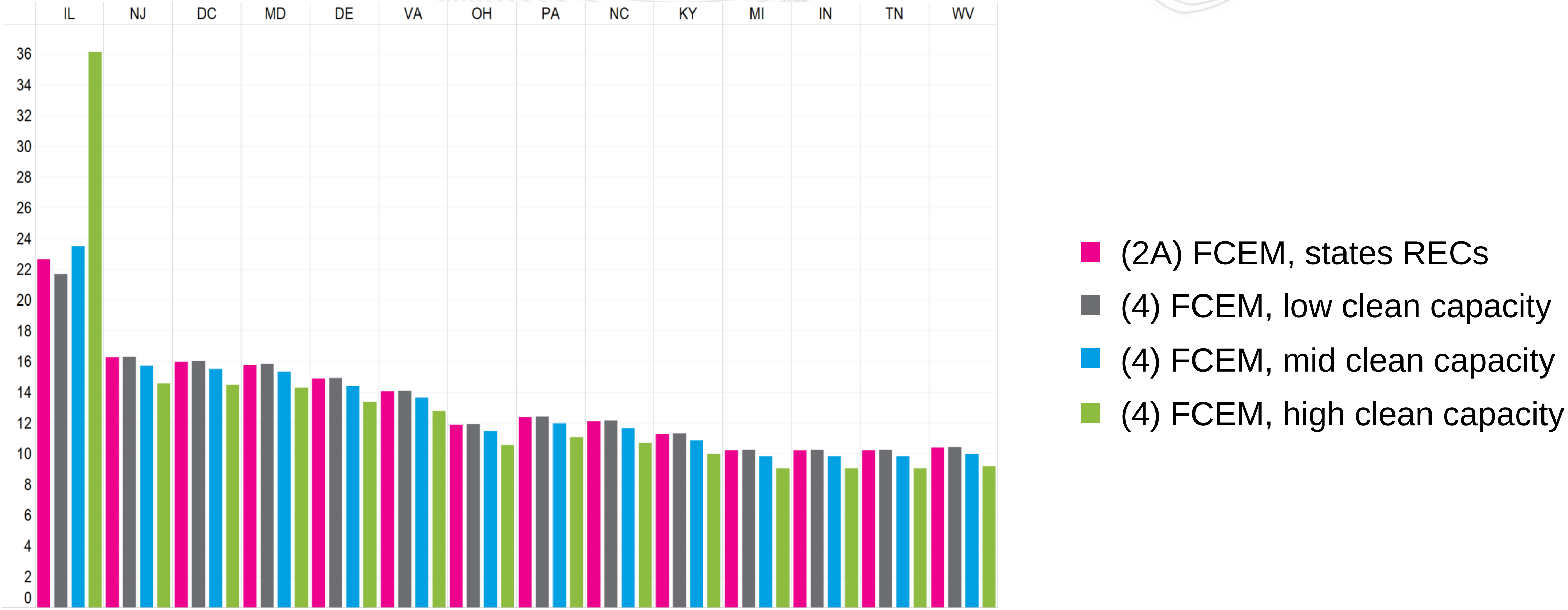
Note: load payments are for PJM and exclude MISO 4. Load payments for the footprint (including MISO 4) are higher for the mid than for the low clean capacity demand case

Clean capacity targets' effect on other products' prices



- Clean capacity targets lower the price of states' RECs (and lead to clean energy procurement above RPS mandates if clean capacity targets are sufficiently high)
- Lower capacity prices, esp. in later years muting the effects of policy retirements
  - The clean capacity constraints attract new renewable units in place of fossil units

Unitized forward markets costs ($/MWh) by state (2023-2030 avg.)



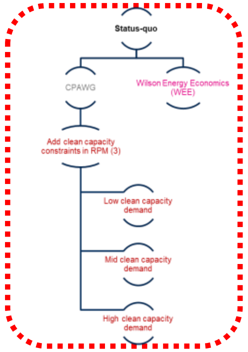
- Clean capacity constraints lower forward markets costs in other states

Unitized forward markets costs = (capacity pmt + clean capacity pmt + clean energy pmt) / load

Nameplate by state and selected technologies in 2030 (MW)

- Clean capacity constraint affect the location and type of investments
  - More solar in IL and less in other states and less combined cycle in IL and PA

Status quo



Status-quo
CPAWG
Wilson Energy Economics (WEE)
Add clean capacity constraints in RPM (3)
Low clean capacity demand
Mid clean capacity demand
High clean capacity demand

Status quo modeling

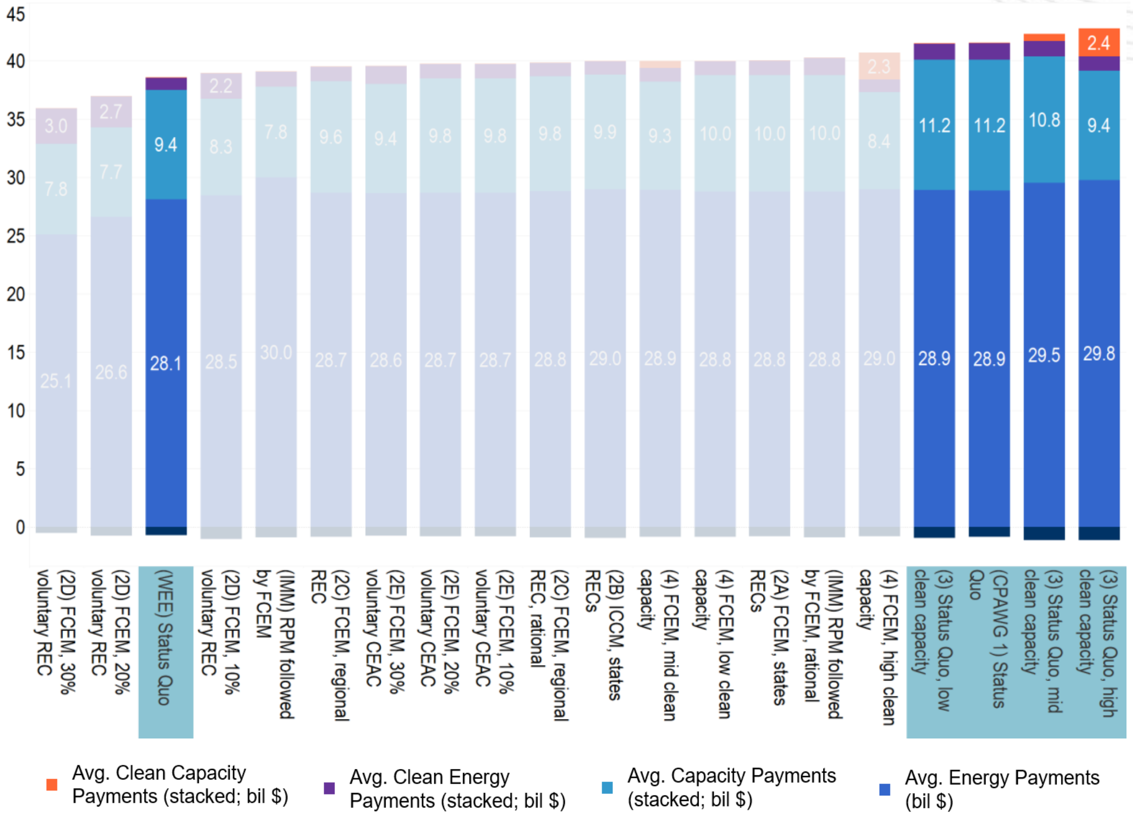
- PJM’s view is that a centralized market would improve welfare *as long as voluntary*. But the model is not well suited to quantifying that improvement because it does not explicitly account for the costs and benefits of the various ways participants trade RECs today, e.g., RFPs, PPAs, self-supply.
- PJM answered CPAWG and Wilson Energy Economics' status quo simulation requests by assuming that suppliers offer unbundled RECs into a centralized market at price:

  Fixed cost × multiplier – expected energy profits – expected capacity payments

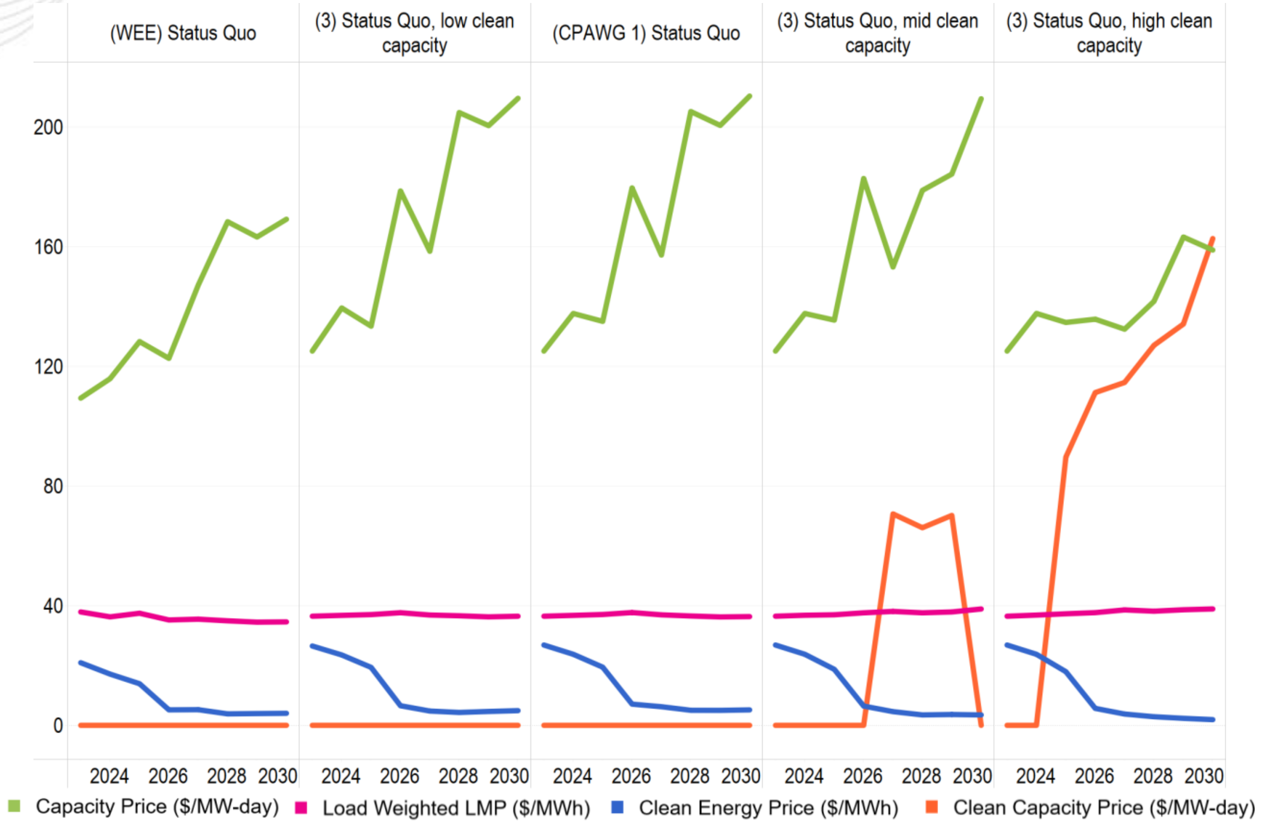
- The multiplier is equal to 1.05 in CPAWG’s requested simulation and 0.95 in Wilson Energy Economics’ requested simulation, reflecting differing assessments of the status quo costs and benefits
- Demand curves are vertical and set based on states’ RPS mandates

Load costs and products' prices

Load payments (average 2023-2030; bil $)



Products prices ($/MW-day and $/MWh)



Status quo results follow bidding behavior assumptions

- In CPAWG's request, resources' offers embody an adder reflecting transaction costs that are assumed to exist in today's market for RECs and mitigated under centralized procurement
  1. Capacity and clean energy prices, and load costs are higher than in the FCEM with states' RECs case (CPAWG's 2A)
  2. Similarly, load costs with clean capacity constraints are higher than in corresponding cases with the FCEM
- In Wilson Energy Economics' request, resources offer at a discount in the status quo compared with the FCEM, reflecting assumed benefits of multi-year commitment and custom provisions
  1. Capacity and clean energy prices, and load costs are lower than in the FCEM with states' RECs case (CPAWG's 2A)

Data overview

The model uses inputs from Energy Exemplar’s Eastern Interconnection dataset, NREL’s 2022 Annual Technology Baseline, PJM processing of publicly available data, PLEXOS for production cost simulation, and PJM’s proprietary models for forward markets and market dynamics simulations.

The Model’s inputs and outputs are published on the CAPSTF webpage, under *Modeling Results.*

List of published scenarios

- Status Quo (CPAWG; 1)
- Status Quo (WEE)
- FCEM, states' RECs (2A)
- FCEM, states' RECs, rational (2A) *
- ICCM, states' RECs (2B)
- FCEM, regional REC (2C)
- FCEM, regional REC, rational (2C)
- ICCM, regional REC *
- RPM followed by FCEM, states' RECs (IMM)
- RPM followed by FCEM, states' RECs, rational (IMM)
- FCEM, 10% voluntary REC demand (2D)
- FCEM, 20% voluntary REC demand (2D)
- FCEM, 30% voluntary REC demand (2D)
- FCEM, 10% voluntary CEAC demand (2E)
- FCEM, 20% voluntary CEAC demand (2E)
- FCEM, 30% voluntary CEAC demand (2E)
- Status Quo, low clean capacity targets (3)
- Status Quo, mid clean capacity targets (3)
- Status Quo, high clean capacity targets (3)
- FCEM+RPM, low clean capacity targets (4)
- FCEM+RPM, mid clean capacity targets (4)
- FCEM+RPM, high clean capacity targets (4)

* Data provided but not discussed in this presentation. Results are similar to ICCM, states' RECs (2B) and FCEM, regional REC, rational (2C) as expected

Raw data files

Model stage	File name	Description	Key
Forward markets	forward_market_offers.csv	Unit-level revenue expectations, costs, and offers in the forward markets (ICCM, FCEM, RPM) and unit-level clearing outcomes	scenario, year, resource_id
	forward_market_products.csv	Products' targets, nesting structure (e.g. LDAs) and cleared quantities and prices	scenario, year, product_id
Spot market	spot_market_units_annual.csv	Units' charateristics (e.g., marginal costs, FOM) and annual energy market outcomes (e.g., generation, profits)	scenario, year, resource_id
	spot_market_zones_hourly_X.csv.zip	Hourly zonal outcomes, e.g. load, generation, imports, exports, LMP, marginal emissions	scenario_index, resource_index, timestamp_index
	spot_market_generation_hourly_X.csv_zip	Hourly unit level state-of-charge, generation, net-generation	scenario_index, zone_index, timestamp_index
Indexes for hourly files	scenarios_index.csv resources_index.csv zones_index.csv timestamp_index.csv	Mappings from scenario name to scenario index for reducing hourly files size; similarly for timestamp and resources identifiers	

PJM has created summary data files

- Content
  - Load, generation, forward products' procured quantities and prices, energy payments, profits, load payments, capital, fixed and production costs, nameplate by types, entry/exit of thermal resources
- Three aggregation levels
  - PJM: `pjm_annual_summary.csv`
  - State: `state_annual_summary.csv`
  - State-zone (includes MISO 4): `state_zone_annual_summary.csv`

Forward products' costs allocation

- Forward products are nested: DELMARVA → EMAAC → MAAC → PJM
- Shadow prices and costs must be stacked
- Example for DE products in FCEM, with states products case (CPAWG's 2A)

product_id	parent	share_of_parent_cost	Quantity procured (MW or GWh)	Procurement target (MW or GWh)	Price ($/MW-day or $/MWh)	Procurement costs (mil $)	Stacked prices ($/MW-day or $/MWh)	Stacked procurement costs (mil $)	cost_owner
RTO-renewable_hydro			97993.9	97993.9	22.6	2211	22.6	2211	
DE-solar	RTO-renewable_hydro	0.023	278.0	278.0	7.9	2	30.4	52	DE
RTO-capacity_types			178638.5	171749.0	116.7	7612	116.7	7612	
MAAC-capacity_types	RTO-capacity_types	0.366	69109.6	49305.6	0.0	0	116.7	2788	
EMAAC-capacity_types	MAAC-capacity_types	0.552	33150.9	24601.8	0.0	0	116.7	1540	
PJM_DelmarvaPL-capacity	EMAAC-capacity_types	0.127	5667.5	0.0	0.0	0	116.7	195	PJM_DelmarvaPL

- Costs are split and propagated iteratively from parent to child using *share_of_parent_cost*: 52 = 2 + 0.023 × 2211 (see `CAPSTF - Model inputs.xlsx`, blue and orange tabs for shares derivation)
- Next, energy (capacity) costs are allocated from the state (zone) to the zonal (state) level using *cost_owner* which keys to the shares in `CAPSTF - Model inputs.xlsx`, tab [state-zone_shares]

Appendix:
Methodology, assumptions, model assessment

Main assumptions, time and space

- Frequency
  - Annual for forward markets (FCEM, ICCM, RPM, etc.)
  - Hourly for energy market
- Footprint
  - 20 zones + Illinois non-PJM portion (MISO 4)
  - 14 Jurisdictions

    36 distinct zones/jurisdictions (e.g. OH-AEP)
  - Transmission limits between zones
    - import limits into MISO 4 set to 0 when solving capacity market
  - Locations differ in fuel prices and renewables’ capacity factors

Main assumptions, resources definition and behavior

- **Resources definition**
  - Representative at the state/zone/technology levels (e.g. OH-AEP-CT)
  - Perfectly dispatchable (e.g. ignore start-up costs and times)
- **Behavior**
  - Existing resources offer:
    - Marginal cost in energy market
    - net-ACR in forward markets
  - New resources offer net-CONE in forward markets (if they clear they become existing and offer net-ACR in subsequent years)
  - In FCEM+RPM, clean resources bid into RPM net of FCEM revenues
  - Only resources clearing in forward markets stay/enter

- Investors and PJM formulate expectations on energy profits and capacity factors by simulating the energy market *virtually* given cleared resources in latest capacity auction, future demand, fuel prices, and anticipated policy retirements
- In the FCEM case, 2023 expected capacity prices are set using ICCM outcomes, and then updated averaging past expectations and realizations

$$\textit{new expectation} = 0.7\ \textit{past expectation} + 0.3\ \textit{realization}$$

Main assumptions, policy

- States RPS targets
- States mandates for offshore, batteries, solar
- NJ nuclear is subsidized
- CT, CC, and CC with carbon capture and storage (after 2027) can be built anywhere (consistent with assumptions in PJM Quadrennial Review of RPM's VRR demand curve and Net CONE)
- Policy retirements as in "Energy Transition in PJM: Resource Retirements, Replacements & Risks" whitepaper
  - Uniformly spread over three years (example, suppose there is a policy affecting a 300MW plant in 2028; we assume 100MW exits each year from 2026-2028)

Main assumptions, average ELCC

- Renewables ELCC change over time as per previously released indicative PJM projections for informational purposes only
- Thermal ELCC = 1 – eFORD from 2023/2024 BRA

	2023	2024	2025	2026	2027	2028	2029	2030
Onshore wind	0.150	0.160	0.150	0.140	0.130	0.120	0.110	0.110
Offshore wind	0.400	0.370	0.350	0.340	0.330	0.310	0.300	0.290
Solar (tracking)	0.540	0.540	0.510	0.470	0.440	0.400	0.370	0.320
Battery	0.830	0.820	0.750	0.740	0.730	0.770	0.800	0.890
Run of river	0.960	0.960	0.950	0.930	0.920	0.930	0.940	0.980
CC	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964
CC (ccs)	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964
CT	0.955	0.955	0.955	0.955	0.955	0.955	0.955	0.955
IC	0.955	0.955	0.955	0.955	0.955	0.955	0.955	0.955
Nuclear	0.991	0.991	0.991	0.991	0.991	0.991	0.991	0.991
Steam coal	0.872	0.872	0.872	0.872	0.872	0.872	0.872	0.872
Steam gas	0.872	0.872	0.872	0.872	0.872	0.872	0.872	0.872
Pump storage	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950
DR	1.090	1.090	1.090	1.090	1.090	1.090	1.090	1.090

- Energy Exemplar’s Eastern Interconnection (EI) dataset for fuel prices, renewables’ capacity factors, list of existing resources and their characteristics, transmission topology
  - Resources are representative to allow data sharing with stakeholders courtesy of Energy Exemplar
  - Existing nameplates by state/zone/technology aligned with IMM’s Q3 2022 state of the market report
- New resources’ characteristics are from EI and NREL’s 2022 Annual Technology Baseline (CT’s major maintenance is in VOM)

Industry trends and model assumptions, fundamental costs

1. Cost pressures from supply chain restructuring and onshoring
   – Brattle's quad study: CC CONE is 35% higher than in NREL
     ➡ We escalate FOM and CAPEX of all new resources by 35%
2. We use fuel prices from Energy Exemplar's Eastern Interconnection dataset predating 2022 energy shocks

(1) and (2) lead to higher capacity and REC prices and costs other things equal

3. It will take time for the IRA to fully affect the queue (e.g., IHS)
   – 5pp CAPEX reduction per year down to 70% in 2028
4. Headwinds to new gas generation investments
   – Gas pipeline capacity
   – Investment uncertainty (e.g. policy)

In the model we ignore these headwinds. New gas investments continue to be economic, mainly in PA

Other technical assumptions

5. Congestion in new solar and onshore wind construction (similar to IHS)
   - In each year and location, 500 MW tranches with 5pp incremental costs per tranche (tranche size is 750MW in ComEd because it is larger than other model zones)
6. About 10.5GW-ICAP do not participate in RPM
   - Shift model VRR by 5GW-UCAP (or, we could adjust supply)

Results for FCEM with states' RECs in 2023 (excludes MISO 4)

Quantities

- Annual Load: 766,818 GWh
- Peak Load: 152,967 MW
- ICAP: 203,817 MW
- UCAP: 178,639 MW
- RECs: 90,318

Prices

- LMP ($/MWh): 37.9
- Capacity ($/MW-day): 116.7
- REC Price: $23.9

Payments (mil $)

- Energy (gross of congestions): 29,039
- Capacity: 7,611
- REC: 2,157

Total: $38,807 mil

System Costs (mil $)

- FOM: 8,114
- Annualized CAPEX: 1,176
- Production: 14,359

Total: $23,649 mil

Emissions

- CO_2 (mil ton): 337.2
- NO_x (1000 ton): 109.6
- SO_x (1000 ton): 101.4