PJM solar and battery forecast 2021: Phase II—Forecasts

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Maria Chea, Senior Analyst, maria.chea@ihsmarkit.com**,** +1 512 813 6324

Sam Huntingon, Director, sam.huntington@ihsmarkit.com, +1 617 866 5180

TC Maslin, Associate Director, tc.maslin@ihsmarkit.com, +1 202 286 0904

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Solar PV and battery forecasting methodology

IHS Markit solar photovoltaics (PV) power and battery forecasting methodology

Analytical framework

The IHS Markit outlook for solar power takes into account multiple drivers and inhibitors that reflect the maturity of the market and its growth potential for solar and batteries.

Key components of our framework for assessing market attractiveness for solar are

- State renewable policy (including renewable portfolio standard [RPS], net energy metering [NEM], community solar, and renewable corporate policies)
- Regulatory incentives
- Solar resources
- Site approval
- Grid access and offtake

Short-term data points

In the short term (one to four years), our forecast is based primarily on existing policies, the late-stage project pipeline, and status of procurement and equipment orders.

Key data inputs collected and assessed by IHS Markit energy analysts include

- Project announcements
- Utility request for proposals (RFPs), auctions, and tenders
- Existing mandates and incentives
- Project development track record
- Reported costs and pricing
- Supply chain announcements and equipment orders

Longer-term assumptions

In the longer term (5–15 years), our forecast draws upon rigorous bottom-up research and on economic fundamentals, energy prices, and macroeconomic factors.

Key data inputs and assumptions include

- Policy and regulatory trends
- Power demand growth and capacity retirements
- Annual solar power pricing forecasts
- Power and gas prices
- Transmission and grid infrastructure

Source: IHS Markit

Key assumptions

Solar forecast scenario overview

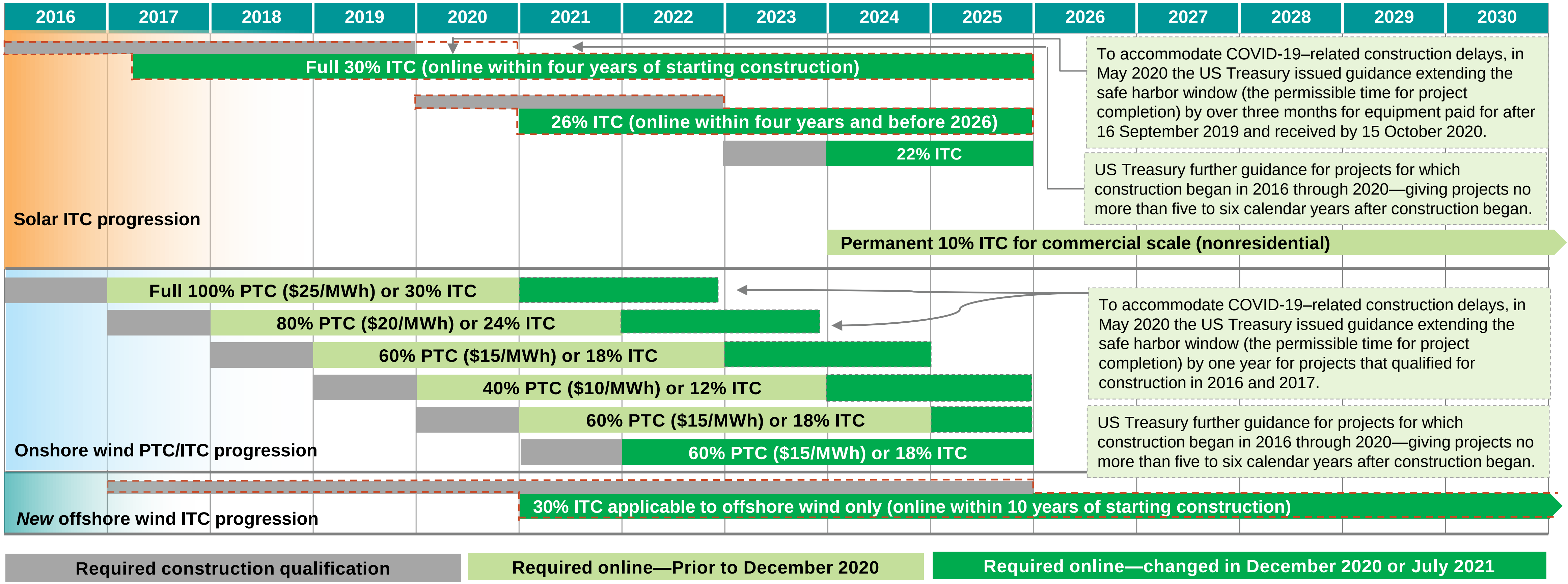
Assumptions	Scenario 1: "DG solar policy reform"	Scenario 2: "Base case"	Scenario 3: "Lower-cost solar"
Federal policy support	Current ITC schedule	Current ITC schedule	Five-year extension of the current ITC schedule
NEM policies and retail rate structures	Utilities/PUCs (and regulators approve) reform NEM policy earlier owing to costly DG programs. Current retail rate structures are adjusted; existing NEM caps are maintained (and many reduced). Utilities and PUCs also phase out "community solar" and carve-outs for DERs.	From 2021 to 2025, utilities adopt (and regulators approve) changes to NEM and retail rate structures, which result in a more cost-based approach to customer-sited solar compensation (see slide 5); current detailed state NEM policy (see slides 6–8).	Current retail rate structures and NEM are maintained for three years beyond the reform timeline in Scenario 2; they are then reformed in a similar manner.
Solar costs ($/kW)	Solar costs decline by 7–23% in nominal terms from 2021 to 2037 (34–42% in real terms).	Solar costs decline by 7–23% in nominal terms from 2021 to 2037 (34–42% in real terms).	Solar costs decline by 31–38% in nominal terms from 2021 to 2037 (49–55% in real terms), driven by a combination of technology advancements and policy incentives.
State policy support	Current RPS policies and state-level incentives are maintained.	Current RPS policies and state-level incentives are maintained.	Current RPS policies and state-level incentives are maintained.
Power demand	Base-case demand	Base-case demand	Base-case demand

Note: DG = distributed generation. ITC = Investment Tax Credit. PUCs = public utility commissions. DERs = distributed energy resources.

Source: IHS Markit

Current US federal tax credits

US wind and solar tax credit availability, reflecting changes made in December 2020



Note: Prior to changes made in late December 2020, offshore wind qualitied for the (then) wind Production Tax Credit (PTC)/ITC. As of December 2020, however, there is a distinct ITC for this technology segment.
Source: IHS Markit

Options for NEM and retail rate reform

- IHS Markit will not predict specific changes to state or utility NEM policies or rate structures; however, we assume states will choose from a variety of options that reduce the compensation for customer-sited solar but still provide sufficient compensation for a moderate pace of additions.
- Holistic rate reform options for all residential customers: lower volumetric (dollars per kilowatt-hour) price in favor of higher
  - Minimum (fixed) bill charge
  - Peak-demand (dollars per kilowatt) charge
- Narrowly tailored NEM reform options:
  - Reduce bill credits for all solar generation exported to the grid in real time (may require new meters)
  - Add “standby” or similar charges for NEM customers only
- NEM replacement options:
  - Value-based tariff (adjusted periodically to account for changes in wholesale power markets, transmission and distribution costs, etc.)
  - Transition toward time-of-use (TOU) pricing for all NEM customers
  - Competitive process (for example, rolling tenders or RFPs)

RPS and NEM policy assumptions by state

Current RPS policy by state

State	RPS target (percentage of retail sales)*	Solar carve-out percentage of retail sales)*/Distributed carve-outs
DE	25% by 2025, 28% by 2030, 40% by 2035	3.5% by 2025, 5% by 2030, 10% by 2035
DC	100% by 2032	2.85% by 2023, 5.50% by 2032, 10% by 2041
MD	50% by 2030	14.5% by 2030
NJ	50% by 2030*	5.1% by 2021, gradually reduced to 1.1% by 2031
OH	8.5% by 2026	0.5% of total electricity supply in 2026 and thereafter
PA	8% by 2021	0.5% by 2021
WV	-	-
IN	10% by 2025 (voluntary)	-
IL	25% by 2025**	No RPS but required 4 million solar renewable energy credits (SRECs) by 2030. Utilities must source 10% of eligible electricity sales from renewable energy by 2015, 25% by 2025 and thereafter.
KY	-	-
MI	15% by 2025***	
NC	12.5% by 2021****	0.2% by 2020****
VA	100% by 2045*****	1,100 MW by 2035 (Dominion only), Dominion is required to meet 1% of RPS requirements from DG sources (>1 MW to <3 MW)
TN	-	-

Note: RPS includes solar carve-outs. *New Jersey RPS target only includes Class I renewable technologies and the solar carve-out. **Illinois solar carve-out requires that 50% of the solar procurements must be from distributed/community solar. RPS mandates at least 75% of the standard come from wind and solar. ***Utilities in Michigan have agreed to 25% by 2030. ****RPS compliance in North Carolina can be achieved through energy efficiency and renewable energy credits (RECs) from any state. *****Phase 1 utilities are required to achieve 14% by 2025, 30% by 2030, 65% by 2040, and 100% by 2050, while Phase II utilities are required to achieve 26% by 2025, 41% by 2030, and 100% by 2045. The primary drivers for solar development include existing Public Utility Regulatory Policies Act (PURPA) policy, planned RFPs, solar resources, solar costs, and the previous state tax credit.

Source: IHS Markit

RPS and NEM policy assumptions by state (continued)

Current RPS and NEM policy by state

State	Utility/territory	NEM cap	NEM system size limits (MW)
DE	All utilities	5% of aggregated customer peak demand (utility can increase the cap)	0.025 (residential), 2 (Delmarva nonresidential), 0.5 (Delaware Electric Cooperative [DEC], Delaware Municipal Electric Corporation [DEMEC] nonresidential)
DC	Potomac Electric Power Co (Pepco)	N/A	For 2021, no more than 140% of the customer's historical 12-month usage, increasing 20% every year until 2024
MD	All utilities	3,000 MW	2 or 200% of customer load
NJ	Investor-owned utilities (IOUs), electric suppliers	None****	100% of customer load
OH	IOUs	N/A	Not to exceed 120% of customer annual average load
PA	IOUs	N/A	0.050 (residential), 3 (nonresidential), 5 (microgrids) (110% of customer's annual load for third-party owned/operated systems)
WV	All utilities	3% of peak demand during previous year	0.025 (residential), 2 (industrial for large IOUs), 0.500 (commercial for large IOUs), 0.050 (commercial and industrial [C&I] for small IOUs)
IN	IOUs	1.5% of utility's summer peak load	1
IL	IOUs, retail suppliers	5% of utility's peak load in prior year	2
KY	IOUs, electric cooperatives except TVA	1% of utility's peak load in prior year	0.045
MI	All utilities	1% of utility's average of the previous five-year peak load. Voluntary cap increase by Consumers Energy and Upper Peninsula Power Company (UPPCO) to 2%.	0.15
NC	IOUs, electric suppliers	N/A	2 (residential customer-owned systems), 1 (commercial systems up to 200% of contract demand)
VA	IOUs, electric cooperatives	6% of load, 1% reserved for low-income customers	0.025 (residential), 3 (nonresidential)
TN	N/A	N/A	N/A

*NEM remuneration is a tariff structure under which the utility pays customers for excess generation, up to a given amount. The most common arrangement is "full retail rate NEM," in which excess generation is paid the same volumetric price that the customer pays for electricity; so, exports are effectively netted against grid consumption over a given period (typically one year). **NEG over that period is sometimes paid at a lower rate, often based on the utility's avoided cost. ***Total remaining excess kilowatt-hours at the end of the calendar year (valued at the generation rate) that amounts to greater than $25 will be refunded as a check to the customer; if less than $25 it will be given as a credit. ****While no mandatory cap exists, it as at the discretion of the New Jersey Board of Public Utilities (NJBPU) to cap at 5.8% of retail sales. *****TREC = transition renewable energy credits. ******Virtual meter aggregation is limited to the account holder's meters and only those within two miles of the POI.

Source: IHS Markit

RPS and NEM policy assumptions by state (continued)

Current RPS and NEM policy by state

State	NEM remuneration for on-site use or export generation*	NEG remuneration**	Community solar
DE	Retail	Retail	Virtual net metering
DC	Retail	Carries over at retail rate indefinitely, at generation rate for systems over 100 kW***	Virtual net metering (less than 5 MW)
MD	Retail	Credited to the customer's next bill at retail rate; reconciled annually in April at the commodity energy supply rate	Pilot program
NJ	Base $152 TREC price ($0.152/kWh), nonresidential rooftop receives full TREC, and ground mount receives 60%; residential rooftop, ground mount, and carport receive 60%*****	Fixed $152 TREC price ($0.152/kWh)	85% of TREC price ($0.12920/kWh)
OH	Less than retail	Credited to next bill at unbundled generation rate (includes energy component but excludes capacity-related compensation	None
PA	Retail	Credited at retail rate for a year; then any leftover excess is credited at generation and transmission portion of the retail rate, but not the distribution	Virtual meter aggregation******
WV	Retail (credits cannot reduce monthly bills below the fixed monthly charge)	Retail	Virtual net metering
IN	Full retail through 2047 for net metering facilities installed through 2017 and through 2032 for those installed through 2022; 125% of average energy market price for facilities installed after 2022 or 1.5% cap is met	Full retail through 2047 for net metering facilities installed through 2017 and through 2032 for those installed through 2022; 125% of average energy market price for facilities installed after 2022 or 1.5% cap is met	None
IL	Retail (TOU for customers paying TOU rates)	Credited to next bill at retail rate; excess at the end of year is granted to utility	Virtual net metering
KY	Less than retail	Utility will purchase all electricity produced at the rate set by the public service commission (PSC), instead of the retail rate	Utility-run program
MI	Approximately 50% of retail	Less than retail	None
NC	Retail	Carries over at retail rate, granted to utility at beginning of summer billing period	Utility-run program
VA	Retail	Retail	Utility-run program
TN	N/A	Retail	None

*NEM remuneration is a tariff structure under which the utility pays customers for excess generation, up to a given amount. The most common arrangement is “full retail rate NEM,” in which excess generation is paid the same volumetric price that the customer pays for electricity; so, exports are effectively netted against grid consumption over a given period (typically one year). **NEG over that period is sometimes paid at a lower rate, often based on the utility’s avoided cost.***Total remaining excess kilowatt-hours at the end of the calendar year (valued at the generation rate) that amounts to greater than $25 will be refunded as a check to the customer; if less than $25 it will be given as a credit. ****While no mandatory cap exists, it as at the discretion of the NJBPU to cap at 5.8% of retail sales. *****TREC = transition renewable energy credits. ******Virtual meter aggregation is limited to the account holder's meters and only those within two miles of the POI.

Source: IHS Markit

RPS and NEM policy assumptions by state (continued)

Current RPS and NEM policy by state

State	Unbundled energy attribute certificates	Virtual power purchasing allowed	Renewable energy offerings from utilities or electric suppliers/green tariff	Production for self-consumption—net metering*
DE	Allowed	Allowed	Retail choice	Up to 2 MW
DC	Allowed	Allowed	Retail choice	Up to 1 MW
MD	Allowed	Allowed	Retail choice	Up to 2 MW
NJ	Allowed	Allowed	Retail choice	Cannot exceed on-site load
OH	Allowed	Allowed	Retail choice	No size limit
PA	Allowed	Allowed	Retail choice	Up to 3 MW
WV	-	Allowed	-	Up to 2 MW
IN	-	-	Green tariff enabled to guarantee sufficient RECs; does not require new build	No size limit under green tariff
IL	Allowed	Allowed	Retail choice	Up to 2 MW
KY	Voluntary	-	Green tariff enabled	Up to 45 kW
MI	Allowed	-	-	No size limit
NC	Allowed	Allowed**	Green tariff in development	Up to 1 MW
VA	Allowed	Allowed***	Green tariff enabled	Up to 1 MW
TN	-		-	-

Note: Green tariffs only include programs where utilities build new renewables on behalf of corporate customers. * Production for self-consumption—net metering refers to the NEM system size limits outlined by state or utility-specific policies **In specific utilities. ***Applies to agricultural sites and school districts for projects up to 10 MW capacity.

Source: IHS Markit

Federal and regional energy storage policy assumptions

Federal and regional energy storge policy assumptions		
Category	**Policy**	**Base case**
Federal	Investment Tax Credit (ITC)	Updated phaseout schedule due to COVID-19, assuming four-year "under construction" guidance (deadline increased to 15 October) or ending 31 December 2023. BESS only eligible if colocated with solar PV and charged directly from associated resource for the first five years of operation.
Regional	PJM capacity market (as applicable to battery)	Assume Minimum Offer Price Rule (MOPR) is revised All other existing market rules, including draft effective load-carrying capability (ELCC) values, remain in place over the forecast period
State/city	Energy storage targets	Remain in current form
State	Tax credits	Remain or expire as currently scheduled
State	Incentives (e.g., rebates)	Assume Virginia’s and New Jersey’s utilities roll out an incentive program for BTM batteries in an effort to comply with the state target. Other states remain unchanged

Note: BESS = battery energy storage system. BTM = behind the meter.

Source: IHS Markit

Battery policies by state

Detailed state energy storage policy assumptions

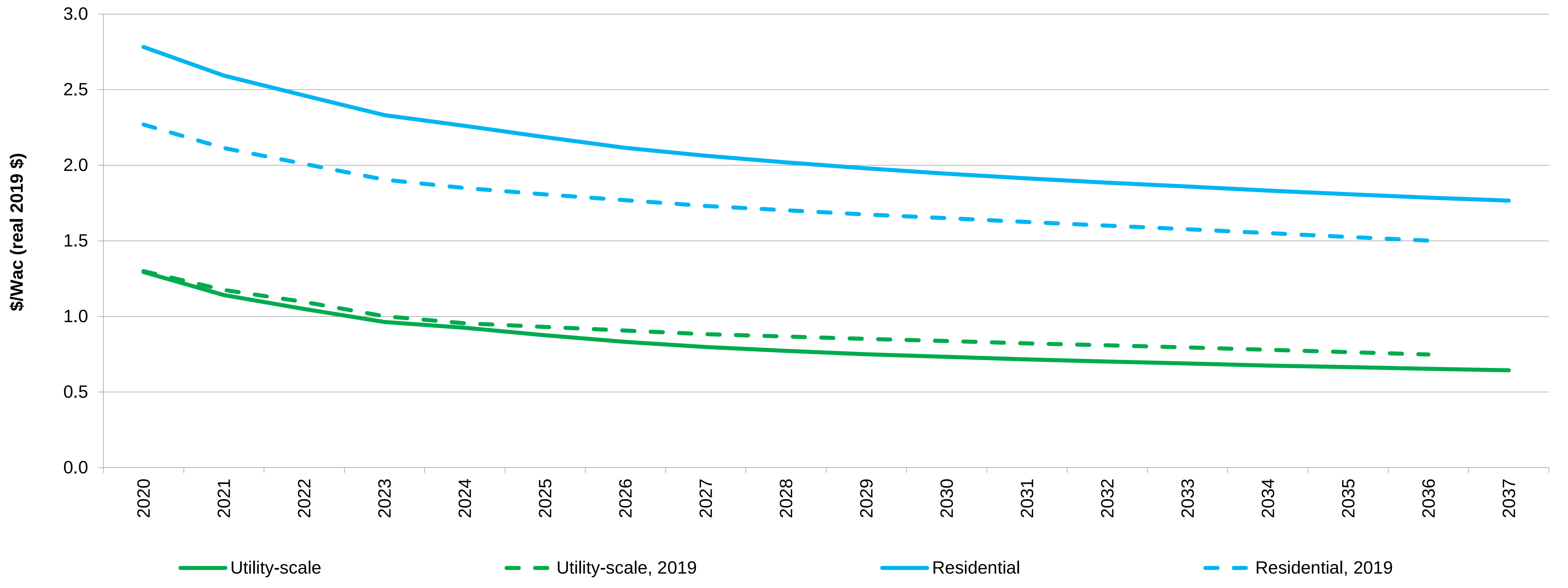
State	Energy storage target (MW)	Tax credit
DE		
DC		
MD	Two 5 MW and 15 MWh pilots by 2022	30%**
NJ	2 GW by 2030	
OH		
PA		
WV		
IN	8% storage by 2039***	
IL		
KY		
MI		
NC		
VA	2.7 GW by 2035 (Dominion), 0.4 GW (Appalachian Power Company)	
TN		

*Maryland's "Energy Storage Pilot Project Act" solicitation offers for IOUs at least two energy storage projects with a cumulative size of at least 5 MW and 15 MWh. **The Maryland Energy Administration (MEA) 2018 Energy Storage Tax Credit Program offered 30% tax credit of the total installation costs (up to $5,000 for a residential project and $75,000 for commercial). ***In May 2018, lawmakers passed legislation (S 2314/A 3723) to implement energy storage targets of 600 MW by 2021 and 2 GW by 2030 and requires the Board of Public Utilities (BPU) to establish a process and mechanism for achieving these targets. ****The regulations instruct Appalachian Power Company and Dominion to construct or acquire 400 MW and 2,700 MW, respectively, of front-of-the-meter energy storage resources by 2035. ***The Indianapolis Power & Light's (IPL) 2019 integrated resource plan (IRP) proposes replacing coal power with renewables and storage, amounting to approximately 240 MW based on an assumed installed capacity of 3 GW.

Source: IHS Markit

PJM solar capital costs (real)

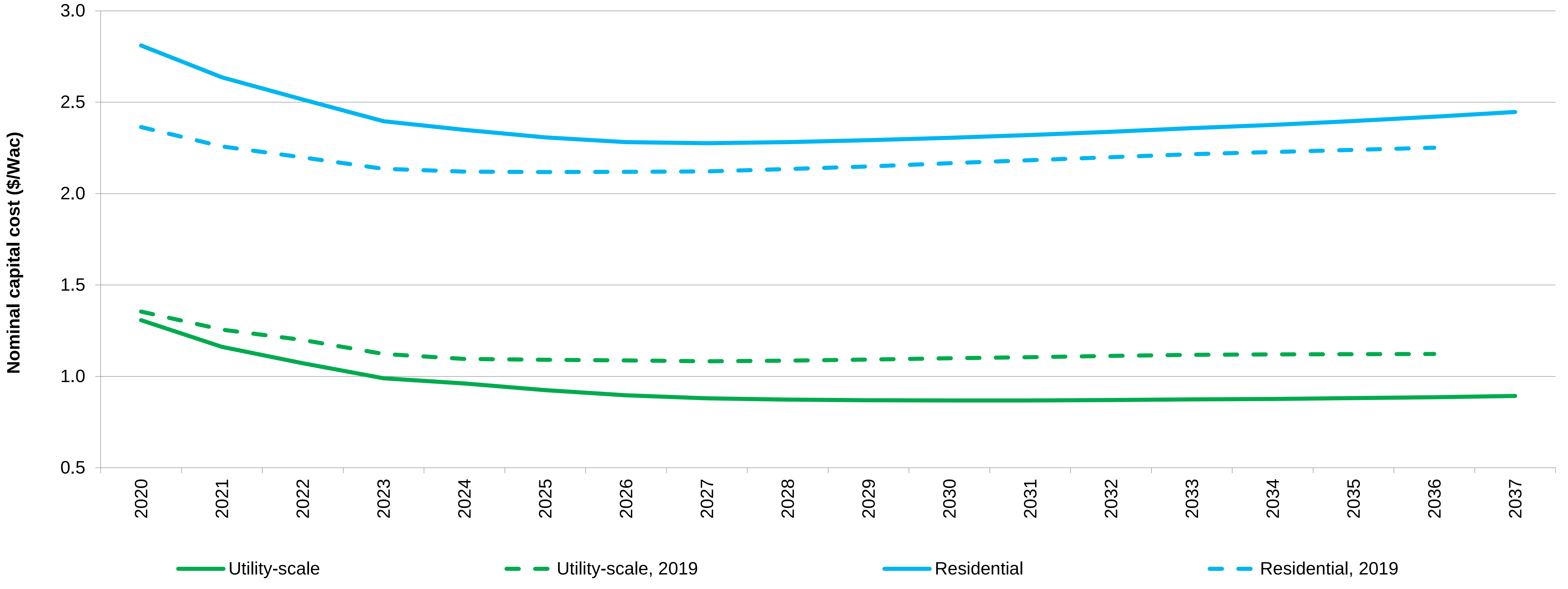
PJM solar capital costs, real



Source: IHS Markit

PJM solar capital costs (nominal)

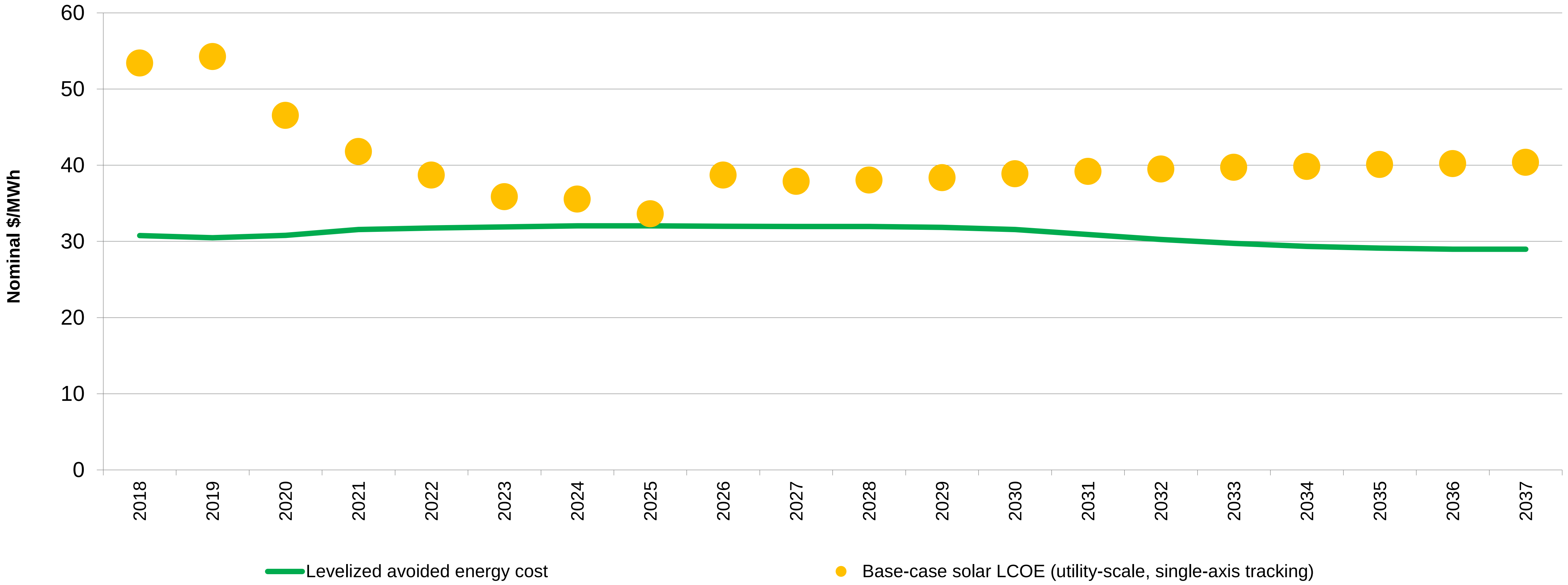
PJM solar costs, nominal



Source: IHS Markit

Utility-scale solar economics

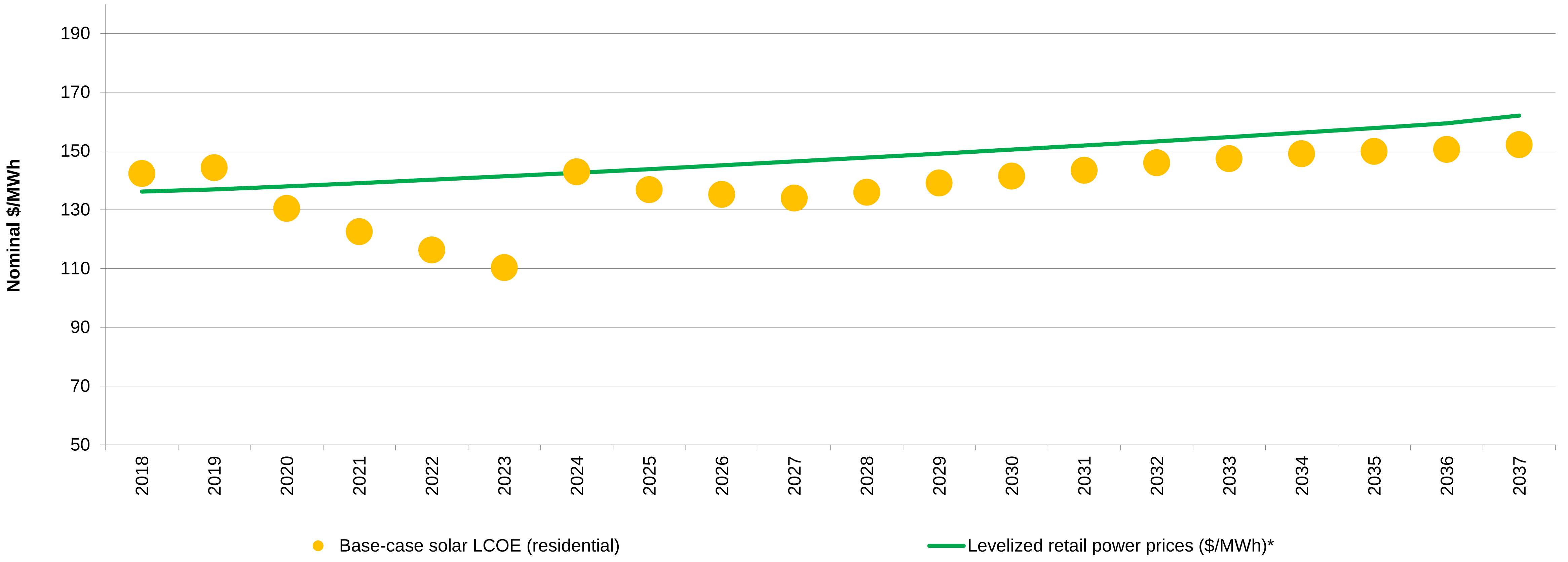
PJM utility solar economics



Note: LCOE = levelized cost of electricity.
Source: IHS Markit

Residential solar economics

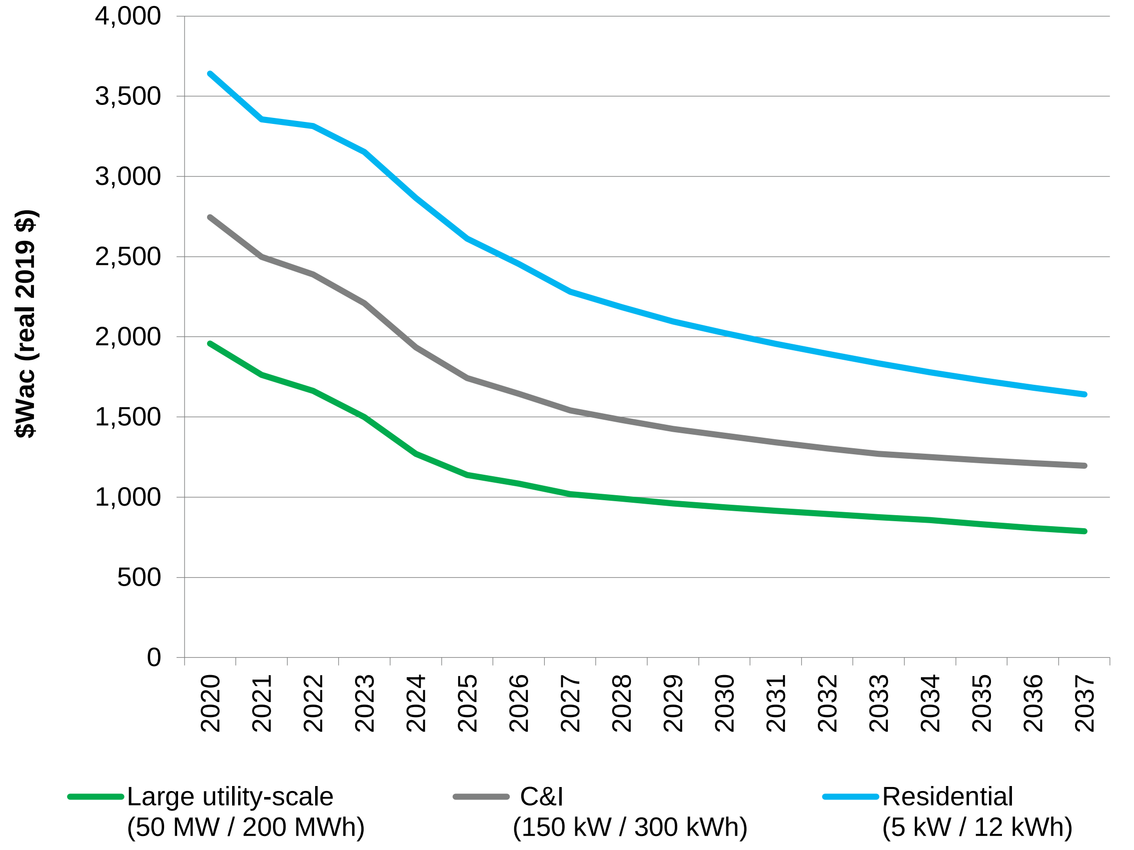
PJM residential solar economics



*Average of Maryland, New Jersey, and Pennsylvania residential power prices and average price increase over the past 15 years.
Source: IHS Markit

Battery capital costs (real)

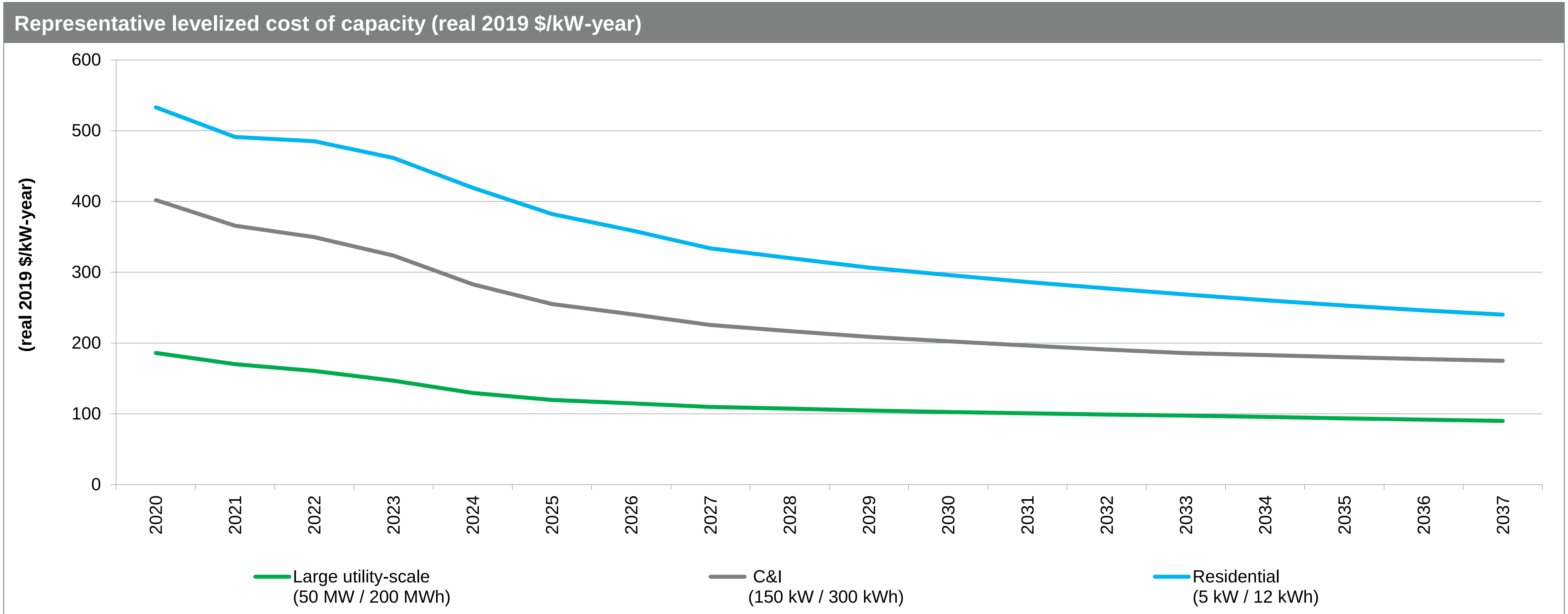
PJM battery capital costs, real



Source: IHS Markit

- **Capital costs for residential and C&I BESS are 2.3 times and 1.5 times, respectively, relative to utility-scale.**
  - Soft costs are significantly larger for BTM systems owing to the diseconomies of scale in installation and high customer acquisition costs.
  - Cost declines in the BTM segment will be driven by falling hardware costs.
  - Total project costs decline by approximately 20% across the BTM segment over the 2021–25 period. Hardware costs decline by 30% during that time frame, while soft costs decline by only 2%.
  - A trend toward larger system sizes, enabled by ever-cheaper batteries, will push down per-unit costs in the BTM segment.

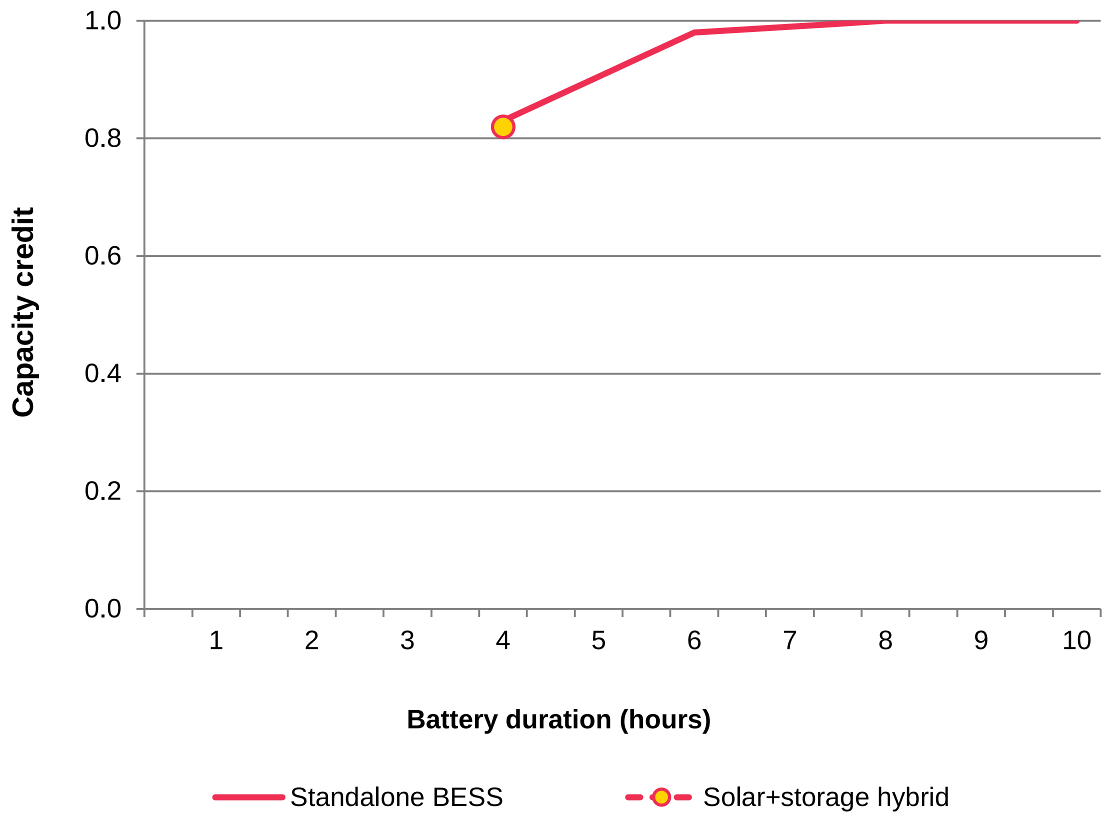
Representative levelized cost of capacity (real 2019 $/kW-year)



Source: IHS Markit

Preliminary ELCC results for PJM’s capacity auction

PJM draft ELCC ratings for 2023/24 Base Residual Auction

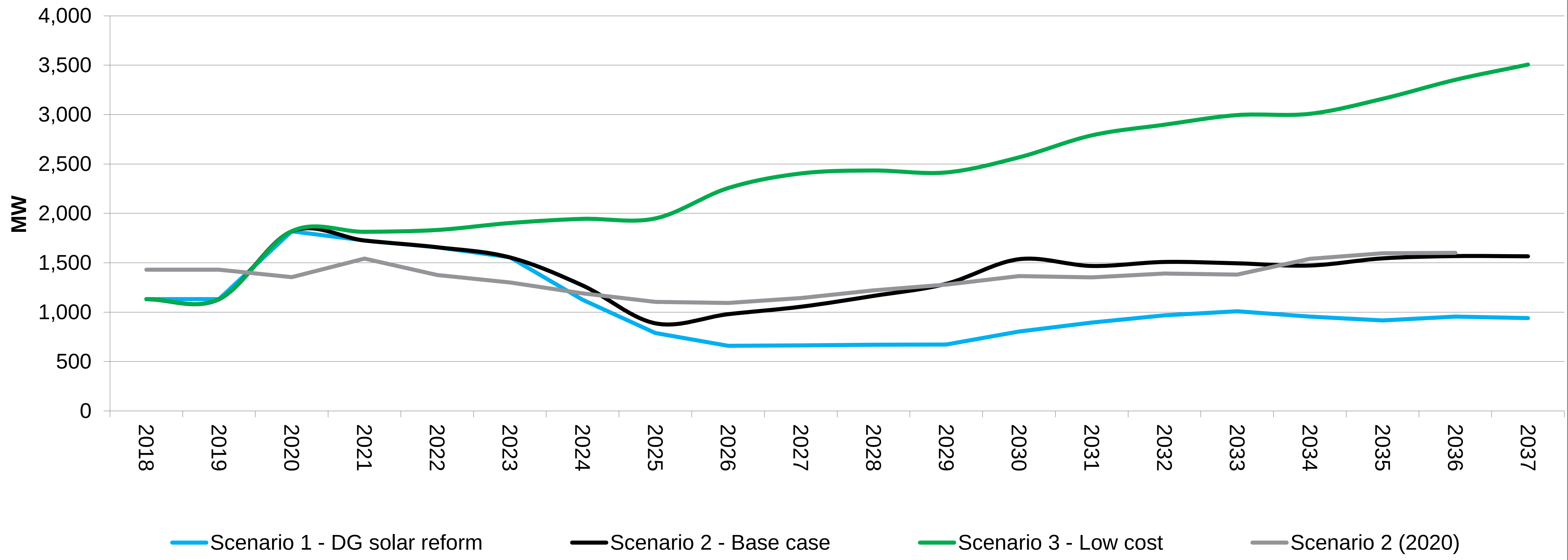


Note: Solar+storage hybrid modeled at a 4:1 solar-to-battery capacity ratio.
Source: IHS Markit

- ELCC values are used to derate a resource’s nameplate capacity to its net qualifying capacity for purposes of capacity market accreditation.
  - ELCC values are expected to decline over time for all resources owing to saturation.
- PJM seeks an effective date of 1 August 2021 for the revisions, which it says would allow the ELCC framework to be implemented starting with the 2023/24 delivery year.
- Hybrids are modeled as 100% maximum facility output—meaning hybrid capacity credit is applied to PV nameplate capacity.
- For hybrids, storage is modeled as four hours and 25% of PV nameplate capacity.
  - E.g., 100 MW PV coupled with 25 MW/100 MWh of BESS

Distribution/BTM solar PV capacity additions by scenario

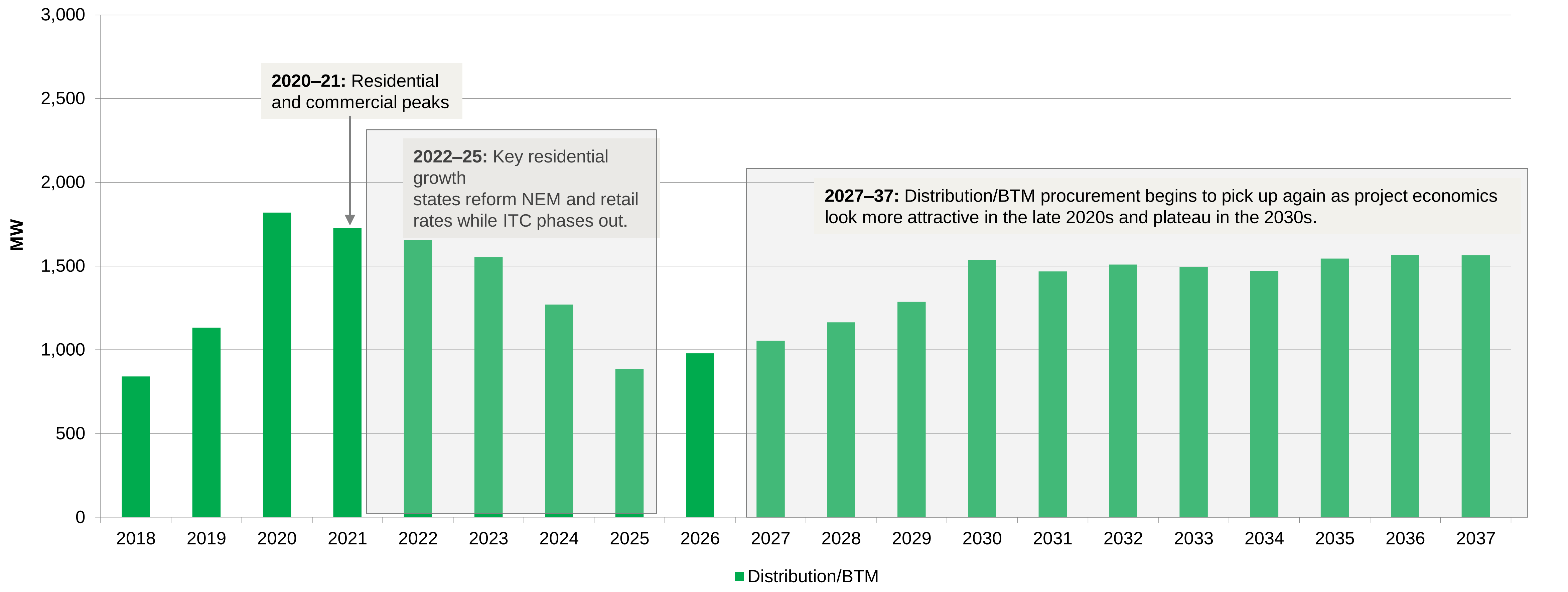
Solar forecasts by scenario



Source: IHS Markit

Distribution/BTM solar PV capacity additions Scenario 2: NEM reform (base case)

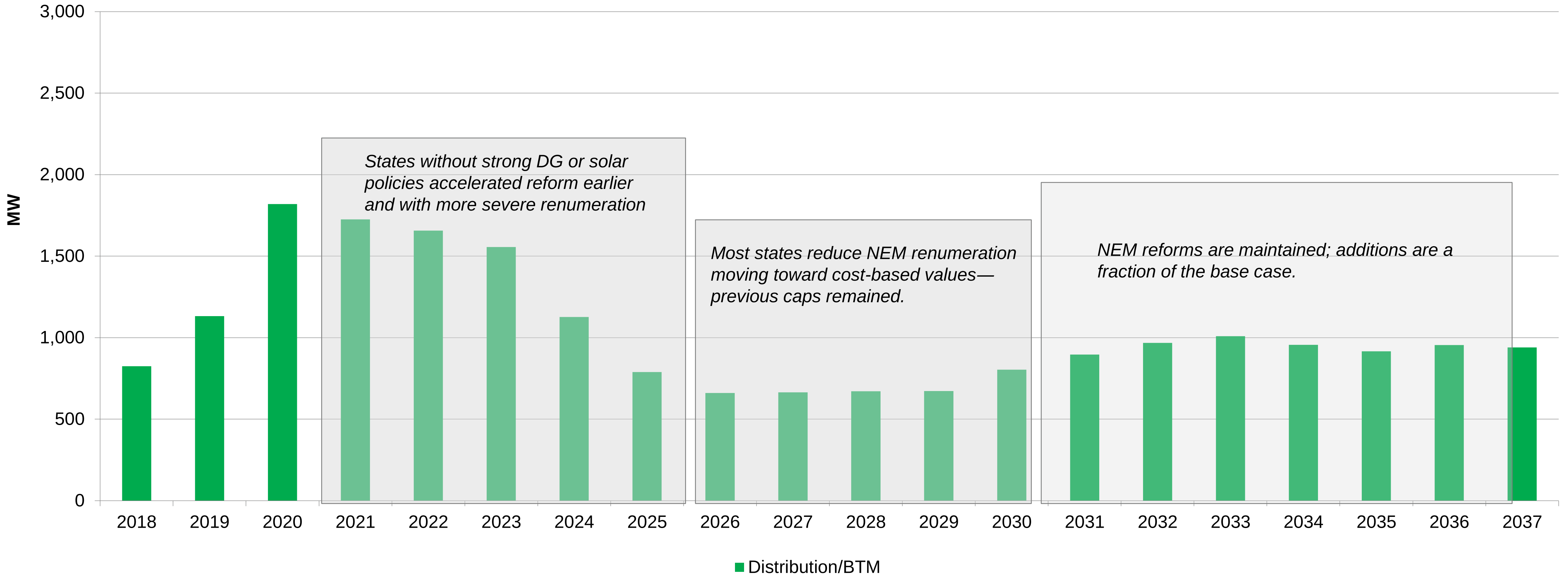
Distribution/BTM solar PV capacity additions—Scenario 2: "NEM reform" (base case)



Source: IHS Markit

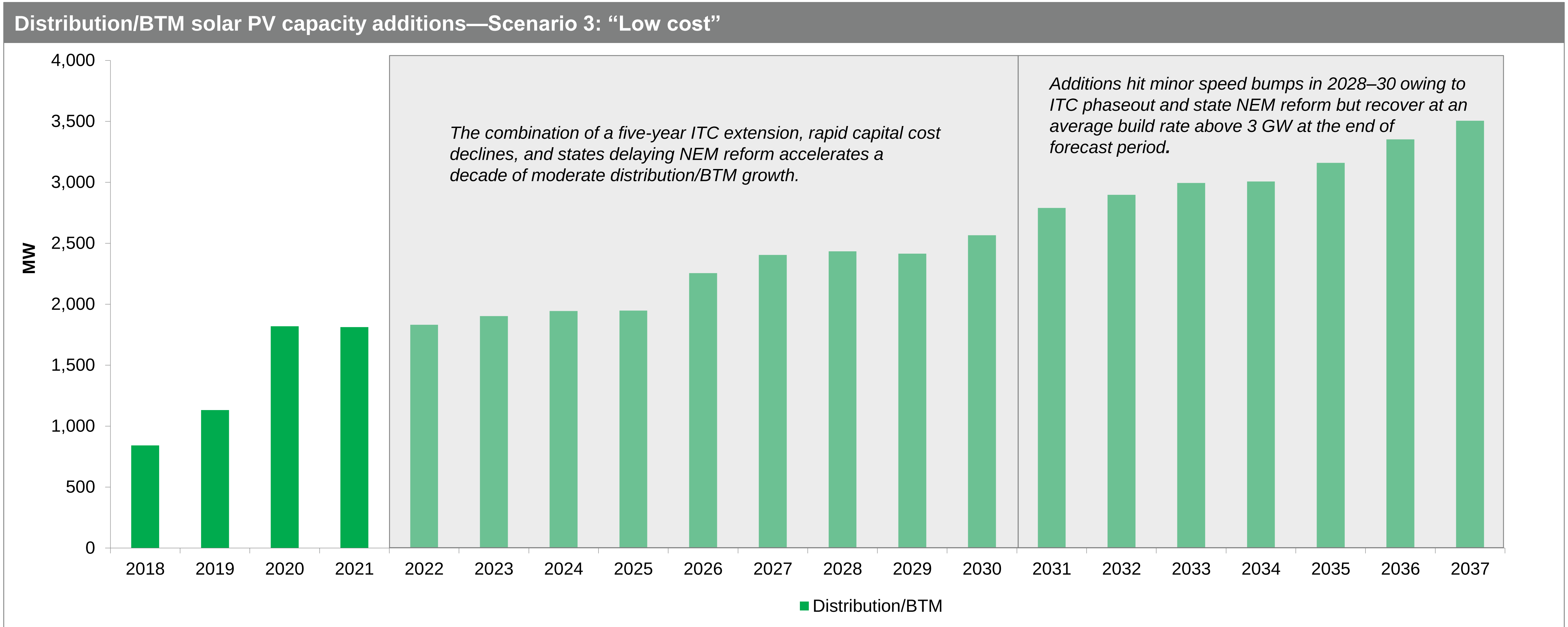
Distribution/BTM solar PV capacity additions Scenario 1: DG solar reform

Distribution/BTM solar PV capacity additions—Scenario 1: "DG solar NEM reform"



Source: IHS Markit

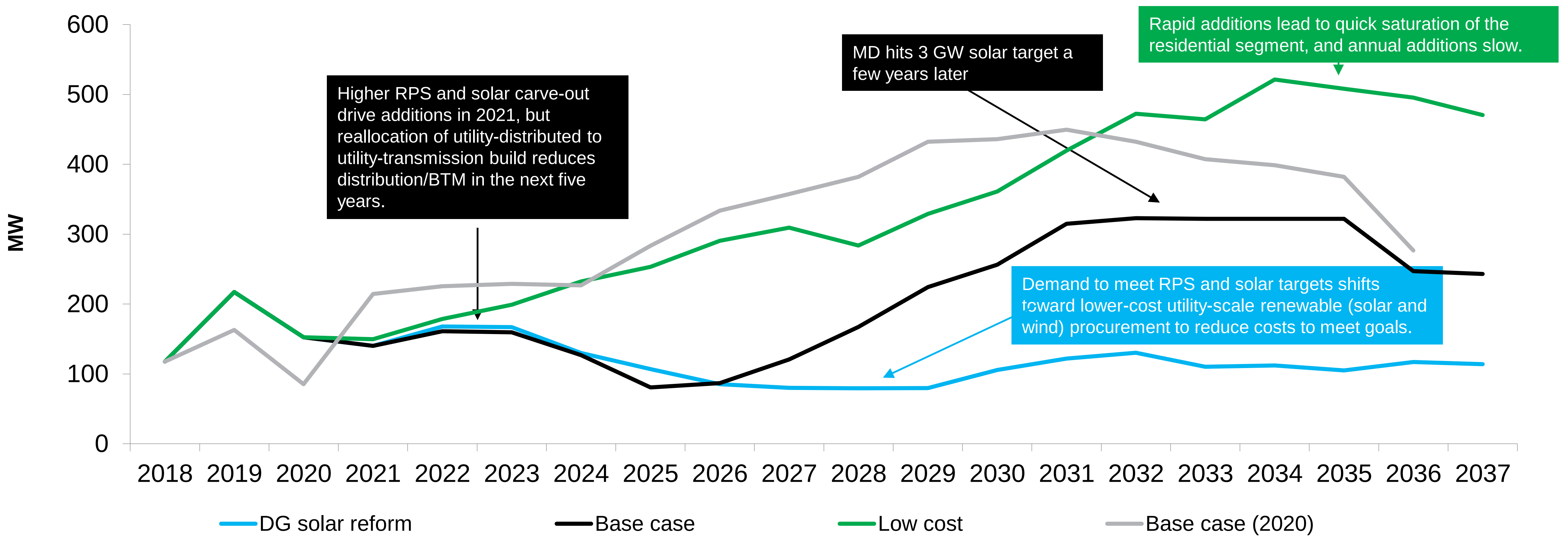
Distribution/BTM solar PV capacity additions
Scenario 3: Low-cost solar PV



Source: IHS Markit

Maryland solar PV distribution/BTM capacity additions by scenario

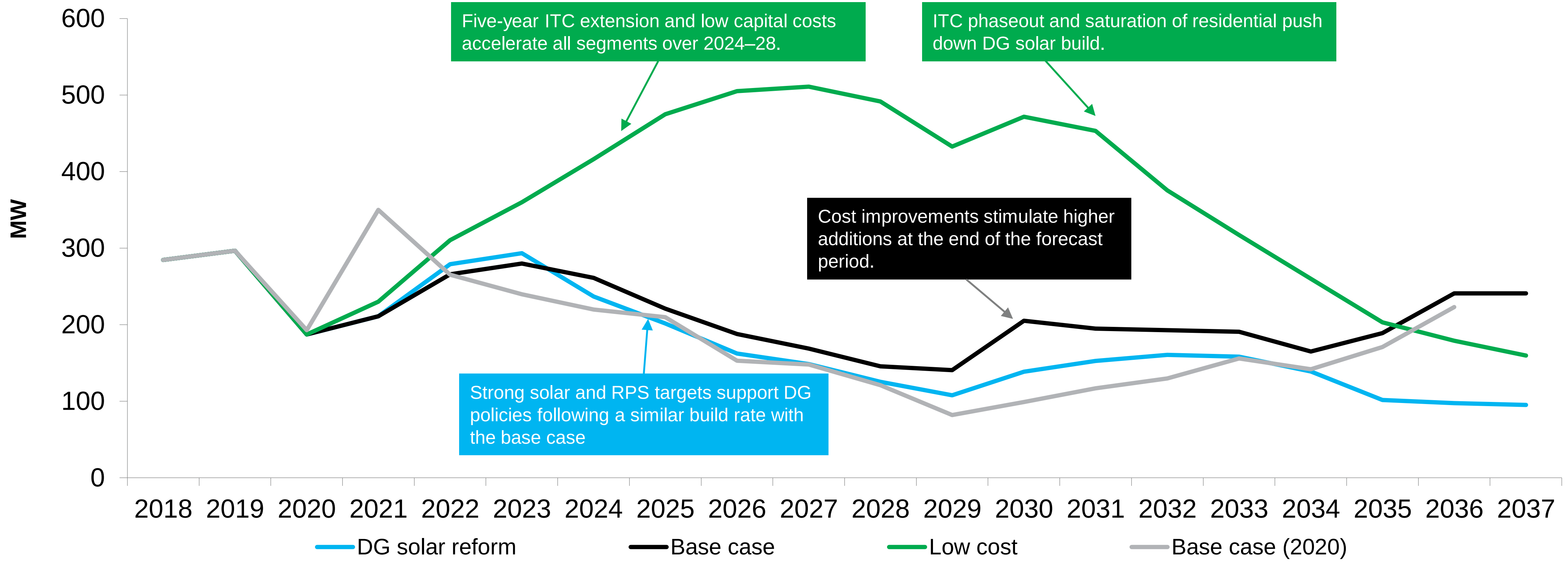
Maryland solar capacity additions by scenario



Source: IHS Markit

New Jersey solar PV distribution/BTM capacity additions by scenario

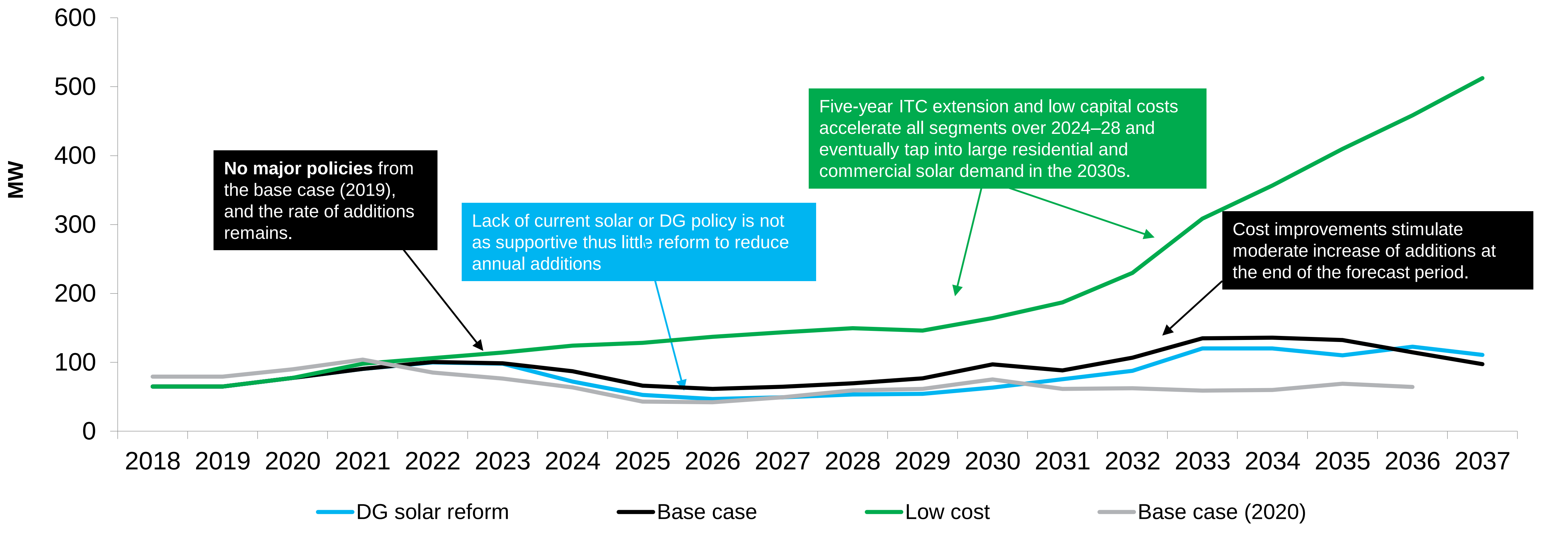
New Jersey solar capacity additions by scenario



Source: IHS Markit

Pennsylvania solar PV distribution/BTM capacity additions by scenario

Pennsylvania solar capacity additions by scenario

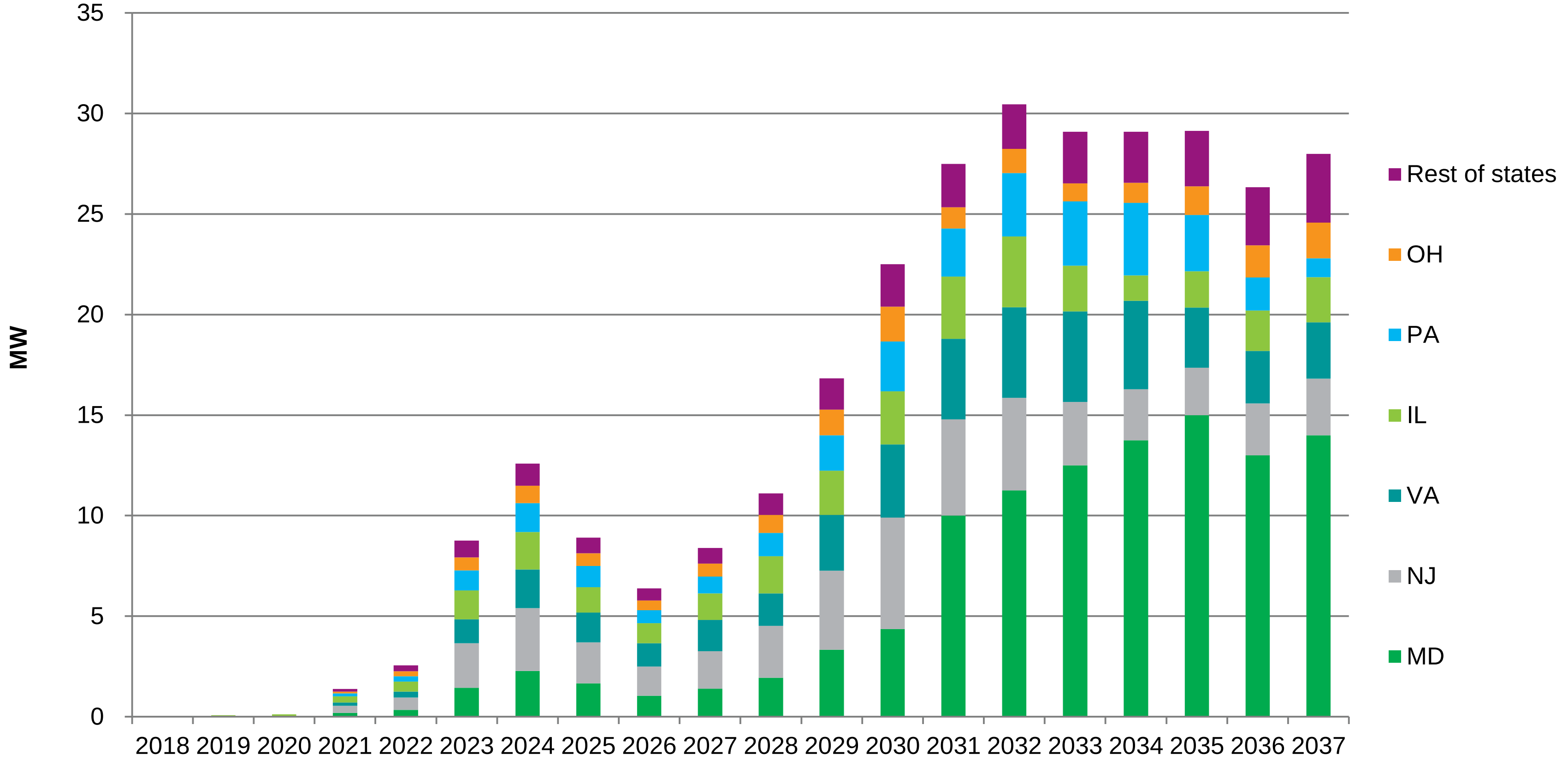


Source: IHS Markit

The residential sector will add ~40 MW of BESS through 2025, led by NJ

Maryland, Virginia, and Illinois will emerge as leading states later in the 2020s. Almost all residential BESS will be colocated with solar PV.

Residential BESS annual installed capacity by state (in PJM)



Source: IHS Markit

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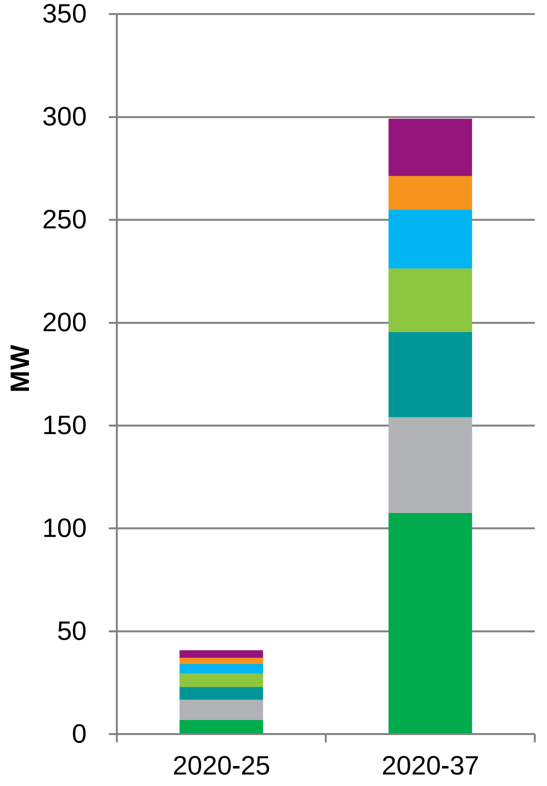
Cumulative residential BESS capacity



Source: IHS Markit

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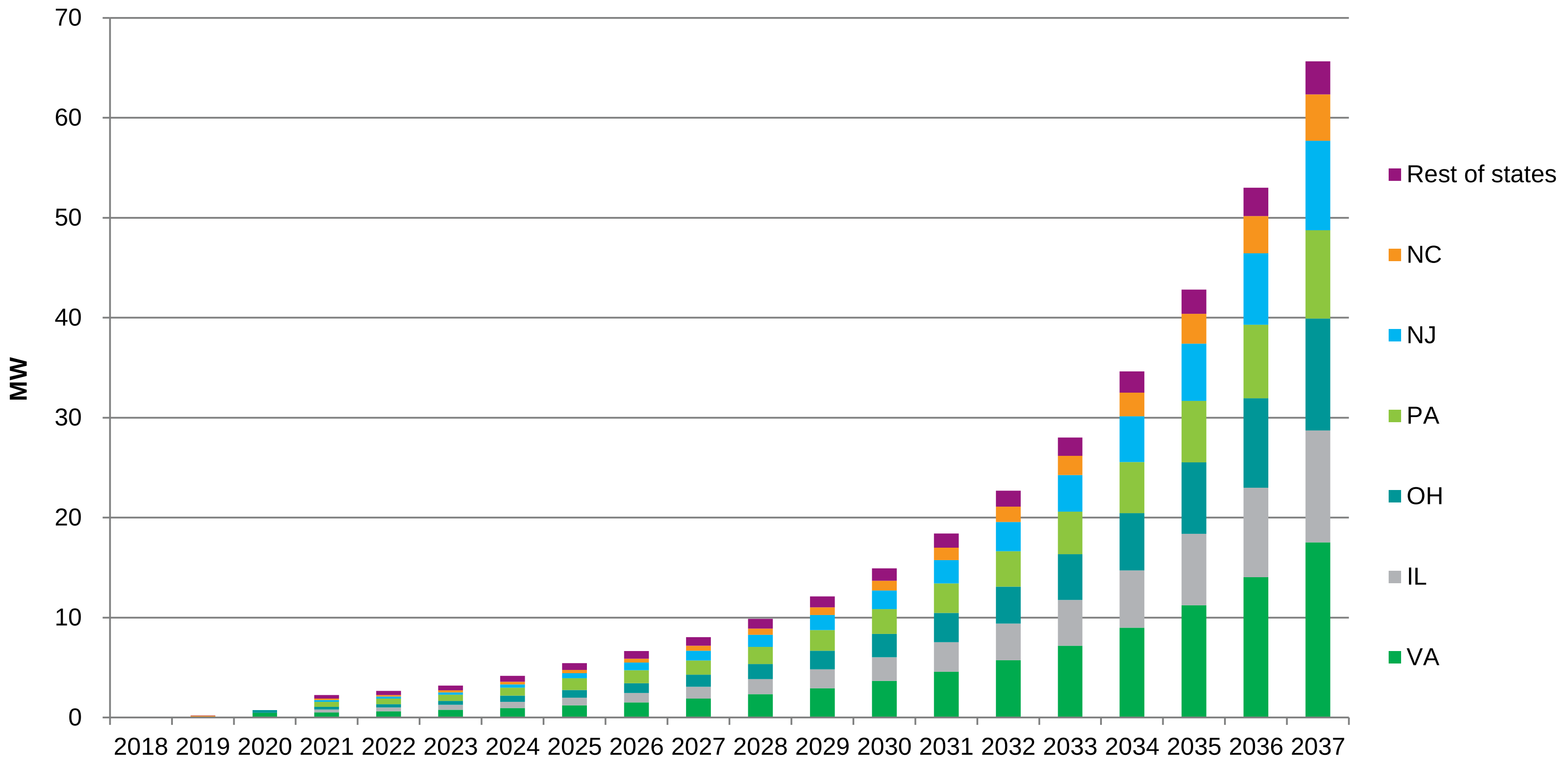
The C&I sector will lag residential in the 2020s but eventually surpass it

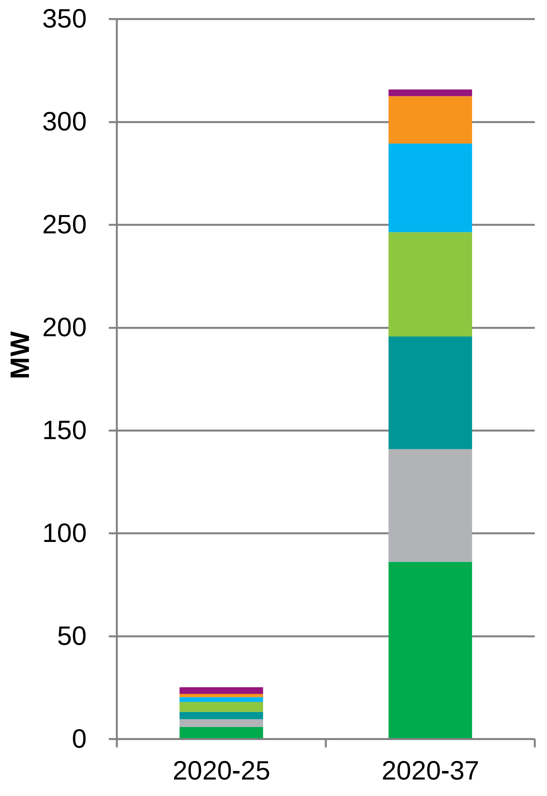
The C&I outlook is driven by the presence of high demand charges and concentration of C&I load.

C&I BESS annual installed capacity by state (in PJM)



Source: IHS Markit

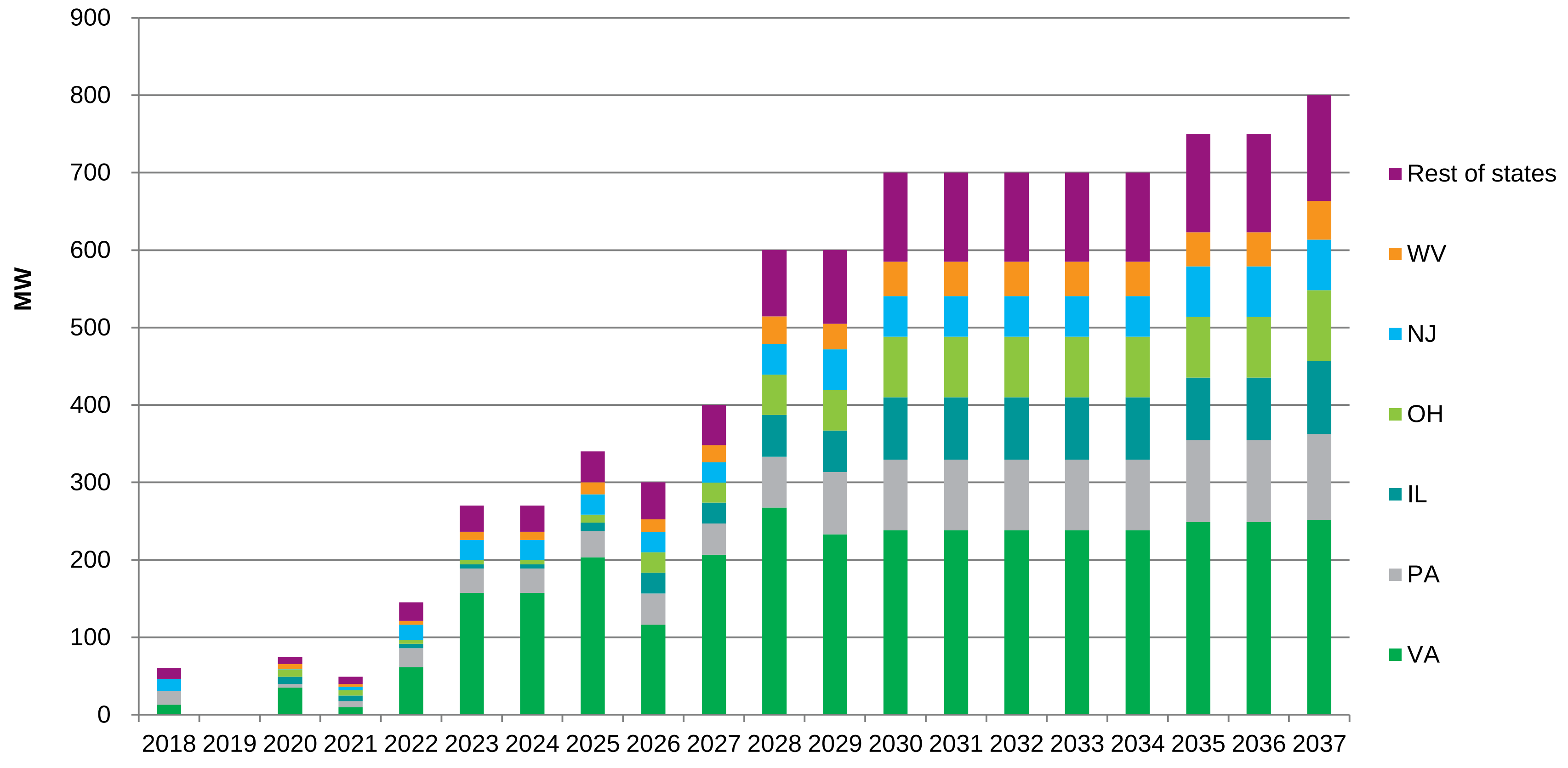
Cumulative C&I BESS capacity



Source: IHS Markit

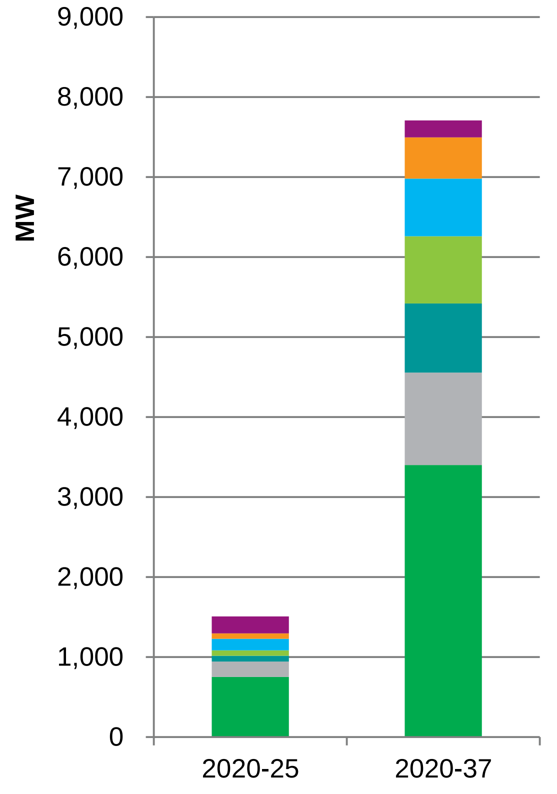
Utility-scale BESS grow steadily through the 2020s, propelled by growth in renewables and increasingly focused on capacity and arbitrage revenues

Utility-scale BESS annual installed capacity by state (in PJM)



Source: IHS Markit

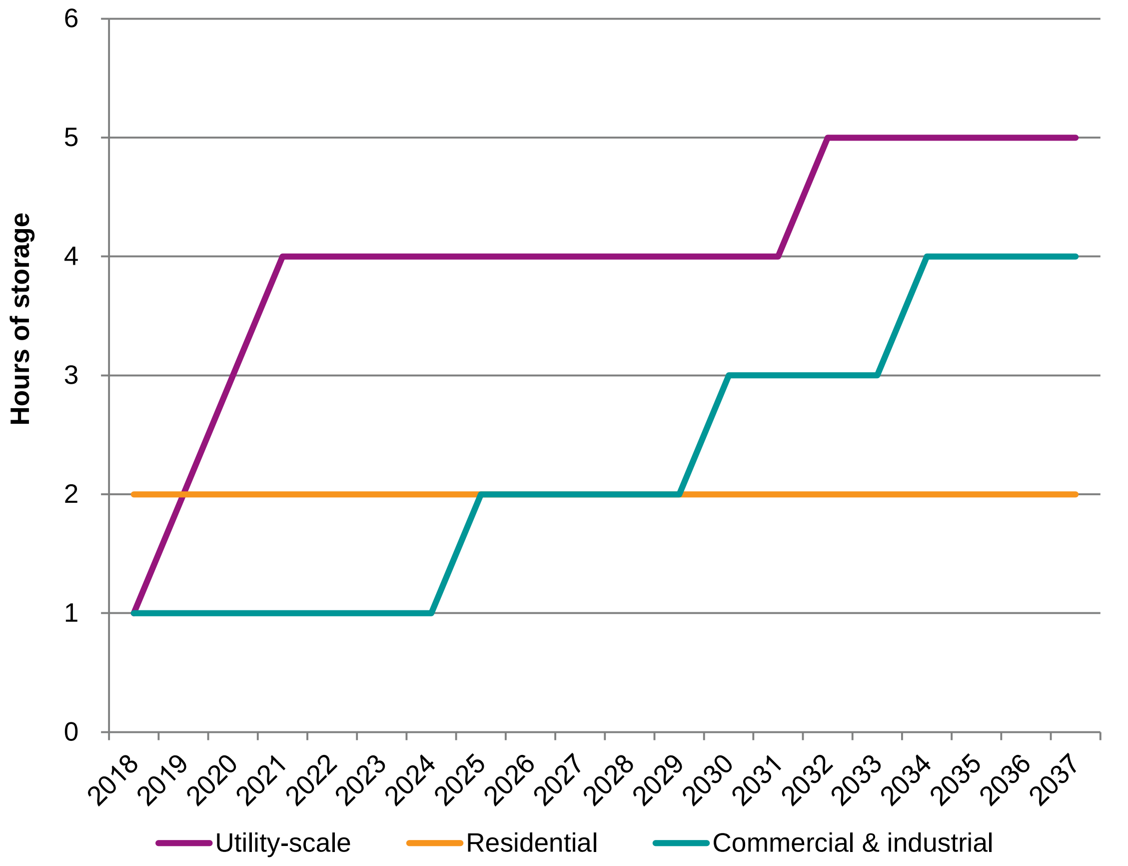
Cumulative utility-scale BESS capacity



Source: IHS Markit

BESS durations generally rise over time but vary by customer segment

BESS duration assumptions by segment

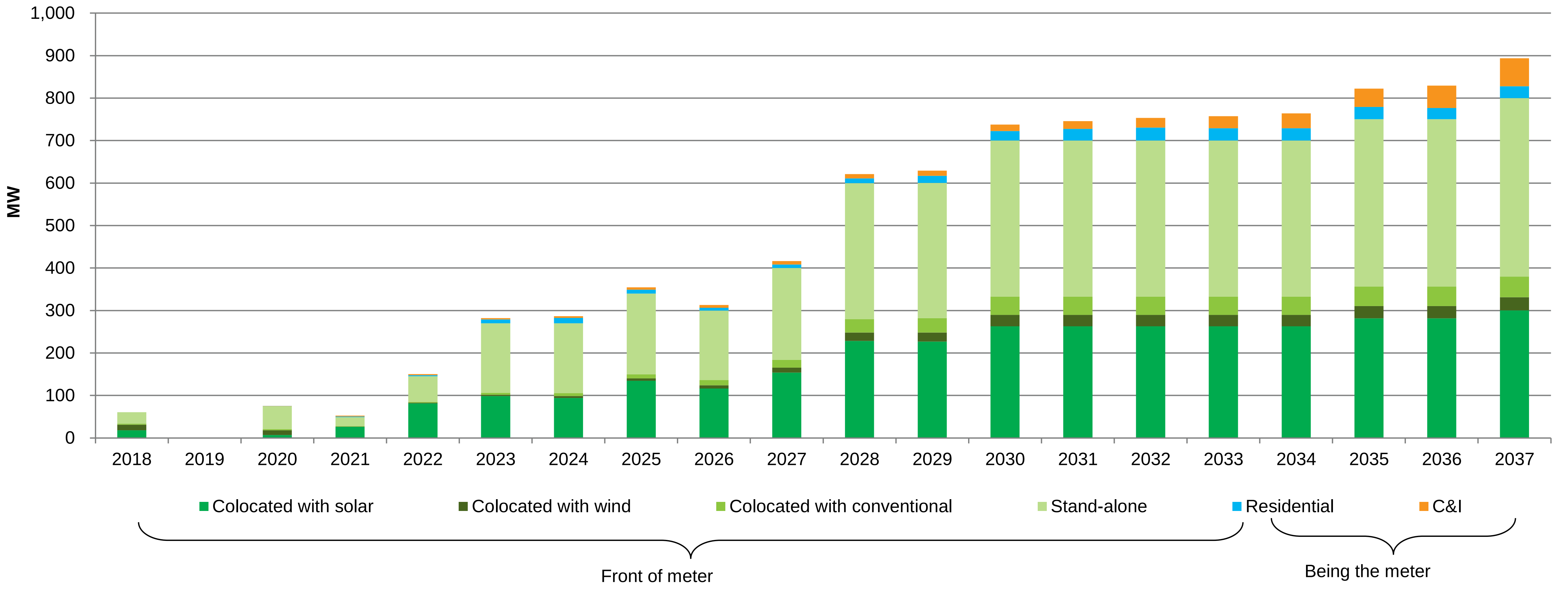


Source: IHS Markit

- Utility-scale
  - Owing to the way battery costs scale with duration, developers will generally build the shortest duration possible to serve a given use case.
  - Historically, most of the batteries installed in PJM had very short durations (15 minutes–one hour) to serve the frequency regulation market.
  - Going forward, durations will rise to four to six hours as batteries turn their focus from ancillary services to arbitrage and capacity.
- BTM
  - C&I durations will remain short through the mid-2020s as customers focus on demand charges. Over time, as use cases shift toward capacity services and backup power, durations will gradually increase.
  - Residential durations are expected to remain about two hours—which is optimal for capturing rooftop solar energy and providing short-term backup power.

Utility-scale BESS dominate the outlook in PJM, with an almost even split between stand-alone projects and those colocated with solar PV

BESS annual capacity additions by customer segment (in PJM)



Source: IHS Markit

Conclusions for solar and battery forecasts (Scenario 2: Base case)

- New state RPS and technology carve-outs (such as New Jersey and Virginia) stimulate further solar in all segments, particularly residential in the near term.
- State full NEM policies bolster BTM growth in the next few years, making up the majority of solar capacity additions.
- IHS Markit expects states to reform NEM policies in 2021–25, dampening further additions.
- States and utilities continue to announce aggressive renewables procurement goals or decarbonization plans.
- Utility-scale solar economics become attractive just as the ITC starts to phase out but annual additions surges at the end of the forecast period.
- A few states will hit a “saturation” point in the forecast period as the low-hanging residential solar sites are gobbled up.
- Battery energy storage system (BESS) capacity additions will be largely utility-scale owing to lower costs and clear business cases based on market fundamentals.
- Residential BESS additions will accelerate in the early 2020’s as several states transition away from full retail rate NEM.
- C&I BESS additions will lag residential through the 2020s, but will eventually become the leading BTM segment as costs fall and business cases improve.

Overview of BESS methodology

Front of the meter (FTM)

- Based on the first-half 2021 outlook
  - Market fundamentals
  - BESS cost outlook
  - Federal incentives
  - Broken out into West, MIDA, and South
- Allocated to PJM zones based on share of peak
- PJM zones mapped to states based on share of load (or peak if we can get the data)

Behind the meter (BTM)

- Based on attach rates of BESS to BTM PV
  - Data from the Lawrence Berkeley National Laboratory (LBNL) Tracking the Sun database
  - Will apply to both residential and commercial
- Applied at state level based on timing of NEM reform
  - Assume solar tariffs become gradually more cost-reflective, creating a larger incentive to attach BESS over time
- Adjustments for state-specific support policies
- States mapped to PJM zones using solar PV allocation factors

IHS Markit Customer Care

CustomerCare@ihsmarkit.com

Asia and the Pacific Rim

Japan: +81 3 6262 1887

Asia Pacific: +604 291 3600

Europe, Middle East, and Africa: +44 1344 328 300

Americas: +1 800 447 2273