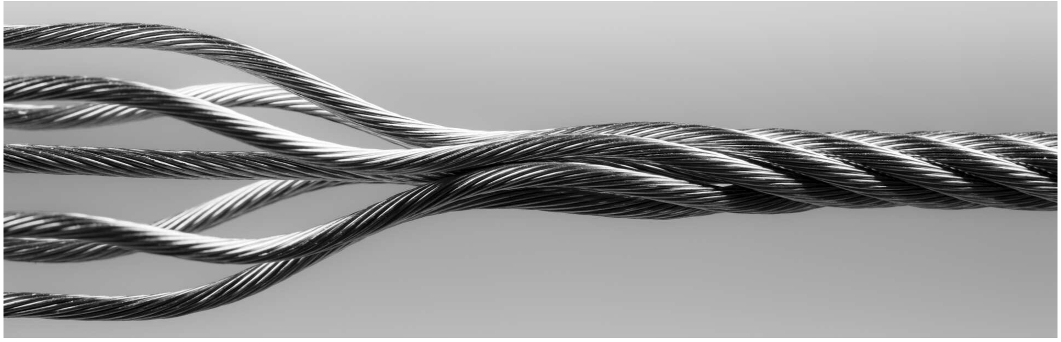
North America Competitive Power

Demand surge and IRA repeal risk dominate credit outlook

January 10, 2025

This report does not constitute a rating action.



What's changed?

The tightness of demand and supply. We expect capacity markets to remain tight, and potentially tighten further, before supply catches up. Energy markets remain well supplied.

Meeting incremental demand cannot be done with renewables alone. We believe all power generators with legacy assets benefit from increased power use.

Credit quality is somewhat 'barbelled'. The competitive renewable segment is under credit pressure while conventional generation companies ride tailwinds. We may see a ratings barbell: upgrades in conventional and credit pressure for renewables.

What are the key assumptions for 2025?

Consolidation and/or incorporation. Estimates for power demand are now at over 2.5% compound annual growth rate over 2024-2030. This surge will result in asset rationalizations, some by aggregation of project finance portfolios into larger corporate vehicles.

Data center transactions. Despite FERC's unexpected ruling on Talen Energy's interconnection supply agreement (ISA), we expect more nuclear power supplied data centers. Gas-fired contracting will also follow.

What are the key risks around the baseline?

Higher tariffs on imported goods, like panels, especially from China.

Partial repeal of the Inflation Reduction Act provisions, affecting the renewable segment's growth trajectory.

Demand surge narrative could be oversold. While electrification, onshoring of manufacturing, and large load data center needs are real, the ability to deploy concomitant infrastructure is a significant concern.

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Ratings Trends: North America Competitive Power

Chart 1

Ratings distribution

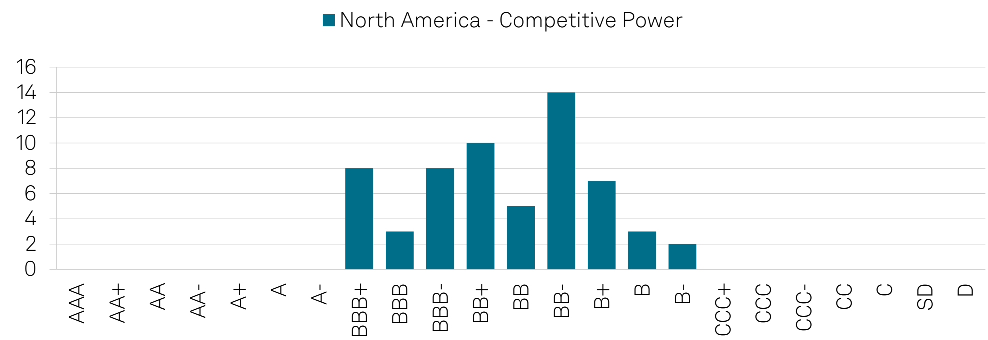


Chart 2

Ratings outlooks

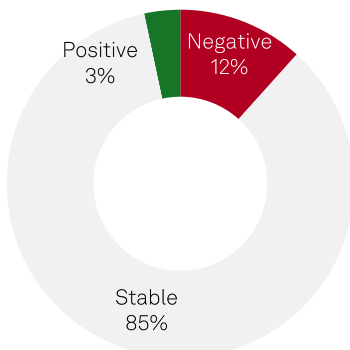
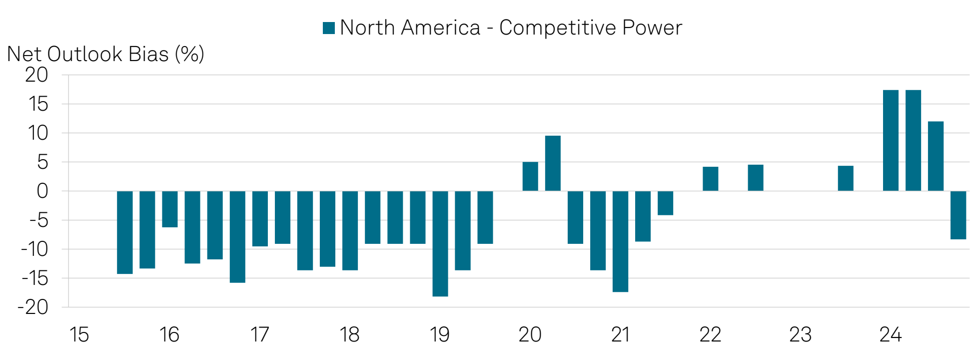


Chart 3

Ratings outlook net bias



Source: S&P Global Ratings. Ratings data measured at quarter-end.

Our rating distribution in the merchant power sector has strengthened in the 'BB' category where it had moved in 2021 (average ratings were 'B+' in 2018). Partly contributing to the move is the improving credit profile of the conventional portfolios and consolidation in the industry, offset by weakening credit profile in the renewable segment. Investment-grade credit quality has also strengthened, after deterioration over the past three years. Negative outlooks, which had declined to 3% at the end of 2022, picked up to over 10% due to pressure on the Yieldco renewable sector but stay below historical levels (17% as of Dec. 2021 and 24% in Dec 2020).

Industry Credit Metrics: North America Merchant Power

Chart 4

Debt / EBITDA (median, adjusted)

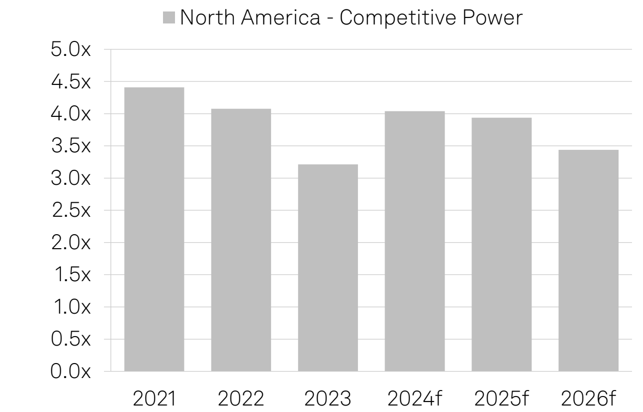


Chart 5

FFO / Debt (median, adjusted)

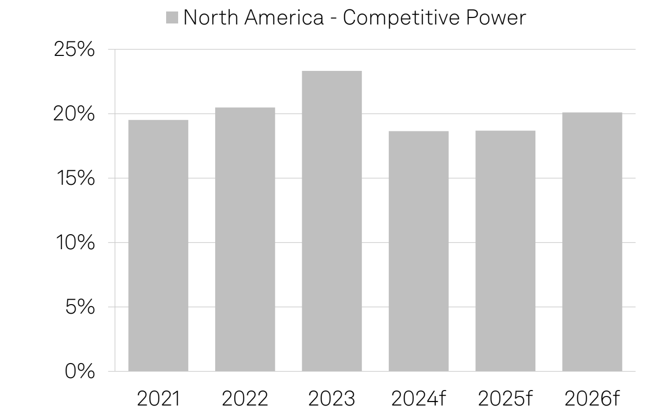


Chart 6

Cash flow and primary uses

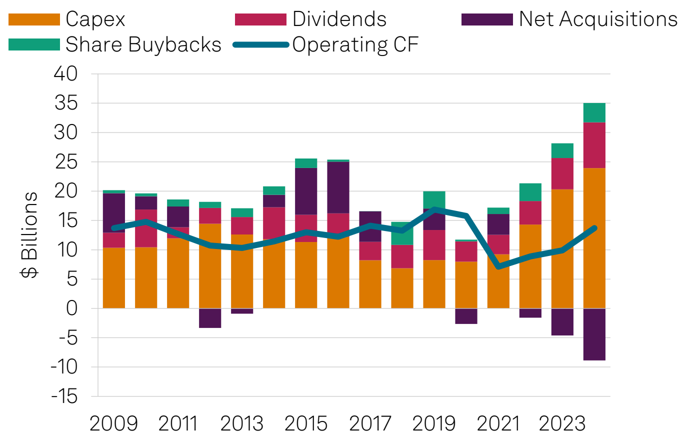
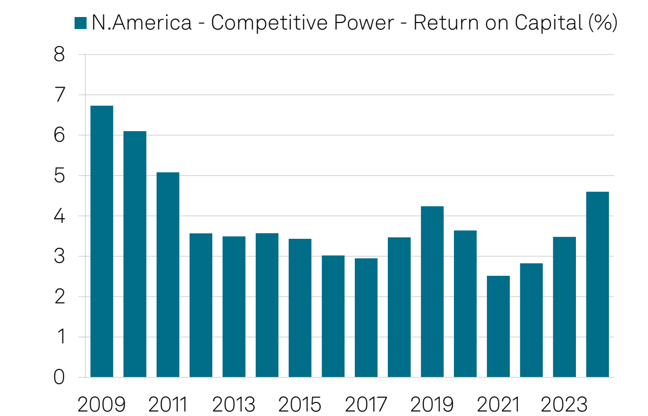


Chart 7

Return on capital employed



Source: S&P Global Ratings, S&P Capital IQ.
Revenue growth shows local currency growth weighted by prior-year common-currency revenue share. All other figures are converted into U.S. dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO—Funds from operations. Most recent (2024) figures for cash flow and primary uses and return on capital employed use the last 12 months' data.

Entering 2024 we expected some Yieldcos and renewable-focused companies to grow meaningfully on the back of tax provisions of the IRA. We expected financial ratios to weaken given the growth was without issuance of commensurate equity. Past winter events had also slowed deleveraging efforts of major independent power producers (IPPs), and some IPPs had slowed their investment-grade aspirations, choosing instead to reallocate excess cash flow to share buybacks and/or acquisitions. As a result, ratios for the sector have weakened overall. In 2025, capital allocation will move to organic growth projects and acquisitions, but also to debt reduction for several IPPs. Most still target adjusted debt to EBITDA in the 2.5x-2.75x range and adjusted funds from operations (FFO) to debt above 25% on a sustained basis. We expect to see credit improvement in the IPP space.

The one segment we think will continue to see incremental leverage are the YieldCos (and unregulated renewable corporates) because of higher interest rates and a significant erosion in their share prices. Securing equity capital for growth could be harder for these companies until interest rates moderate.

Industry Outlook

Ratings trends and outlook

1. Capacity markets have tightened.

We expect elevated resource adequacy (RA) prices in California—where prices are in the low double digits ($/KW-month) through 2030—and in the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, where capacity prices increased 9x in the latest auction (2025-2026) over the previous year.

2. Renewables PPA prices have more than doubled since first quarter 2021.

Market-averaged solar and wind PPAs are up 10% and 17%, respectively, year-over-year, the twin impacts of higher costs (labor, panels) as well as higher interest rates.

3. Stable ratings profile but pockets of risk.

We expect robust cash flow generation and high cash flow conversion from the IPPs, provided operating performance remains intact. Perversely, renewable companies are short equity capital for their financing needs.

Power growth is finally here. In January 2024, the PJM, the biggest independent system operator (ISO) in the U.S., increased its demand forecast to a compound annual growth rate (CAGR) of 1.7% through 2030, up from 0.8% the previous January. Revisions of growth expectations are not unusual so the news did not stand out. But then forecast revisions started accelerating. By June 2024, our affiliate, S&P Global Commodity Insights, revised its power CAGR for the contiguous U.S states to 2.1% for 2024-2030 from a CAGR of 1.2% as recently as January 2024. Compounding can be deceptive—it can hide growth—so this differential in CAGR is significant, especially when compared with demand that had stagnated.

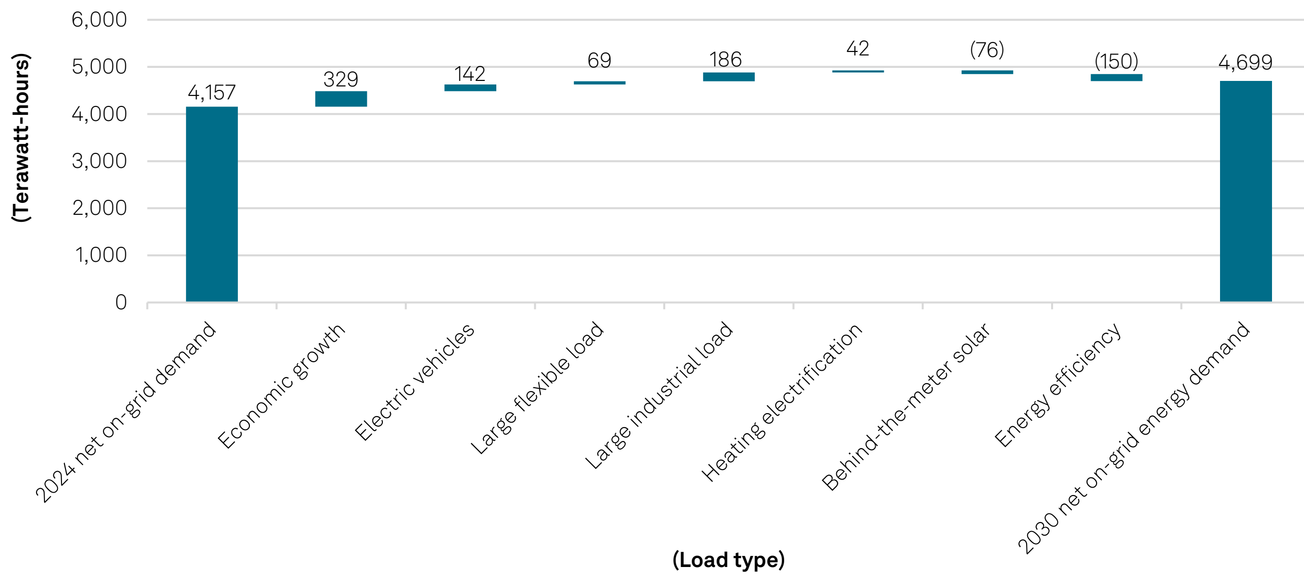
Over the past decade the increase in demand from customer growth and electrification needs was offset by energy efficiency (e.g., building codes and efficient appliances) and behind the meter solar installations. The current growth surge is spurred by large loads (see chart 8). Electric vehicles and large flexible loads (e.g., electrolytic hydrogen and industrial processes) will drive significant demand between 2030 and 2050. However, data centers may account for 20%-30% of all net new demand added between any two consecutive years until 2030.

Bottom line, in a demand growth scenario we see owning generation as a credit positive, especially if it is dispatchable, and at scale. Nuclear generator such as Constellation Energy benefits most, followed by others like Vistra Energy, Calpine Corp, PSEG Power, Talen Energy, and NRG Energy.

A major setback facing the IPP sector the past decade is the loss of the long-term investor. Wary of the asset lives around fossil fuel generation, the long investor had all but left the sector. The present demand surge has made many investors rethink how to position their holdings. We expect owners to start aggregating portfolios under a corporate structure, and expect to see new IPPs emerge. We think the critical mass that sponsors need to organize a new IPP is about 5 GW. It is not surprising that we saw the formation of corporates like Lightning Power LLC and Alpha Generation LLC in 2024

Chart 8

U.S. power demand through 2030



Sources: S&P Global Commodity Insights and S&P Global Ratings.

Capacity markets to remain tight, benefiting prices. In most parts of the U.S., generation capacity is increasingly appreciated. The explanations are similar: Over the past years, supply/demand imbalance has grown. However, a longer line of reasoning also includes long interconnection queues. There is also insufficient future transmission planning and now the problems have simply cascaded, resulting in several regional transmission organizations (RTO) short on MW capacity for power delivery. While future capacity auction outcomes are yet to be set, bilateral capacity continues to be contracted at high price levels in New York and California.

We see capacity shortages glaringly in the sharply elevated resource adequacy payments in California—which are holding steady in the low double digits through 2030—and in the last PJM Interconnection capacity market auction price (for delivery year 2025-2026), which increased 9x over prices set in the previous auction (2024-2025).

Earlier this year, PJM published parameters for the auction for delivery years 2026-2027 (that was to be held in Dec. 2024 but is now delayed). For this delivery year as well, demand and reliability requirement are higher than the July 2024 auction by 3.3 GW and 2.8 GW, respectively, and installed reserve margin is now 18.6% compared with 17.8%. All these revisions point to higher price outcomes, and there is really nothing in the latest parameters that leads us to expect prices to recede materially from the 2025-2026 levels. Based on the parameters presented, we believe the prices set in the auction would have been higher—potentially topping $300/MW-day—and higher than our current assumptions for capacity year 2026-2027.

The FERC has recently issued an order granting PJM's request to delay its 2026-2027 capacity auction by six months to June 2025. We expect parameter changes in the coming months to include reverting the reference unit back to a combustion turbine, lowering the gross cost of new entry (CONE), potentially easing upwards price pressure. We also see risk of the Talen Energy reliability-must-run units being included as generation supply in this auction (roughly 1.4 GWs of unforced capacity), which should also have a dampening effect on pricing outcome in the auction. Conversely, we see the potential for higher demand—on Nov. 25, 2024, the PJM added 1.8 GW to its 2025 load forecast but increased 2030 forecasts by 17 GW.

As a separate yet related point, we note that systemwide PJM capacity costs to load climbed to $14.7 billion in the latest auction, the highest they have been. Notably, this cost is meaningfully higher than the $2.2 billion in the previous two auctions. Therefore, we expect some political backlash given customer price impacts. The high prices will likely drive stakeholders to advocate market changes and possibly out-of-market interventions.

Renewables PPA prices have more than doubled since first quarter 2021, stalling the downward cost curve of power prices. Solar and wind market-averaged price index have increased to over $55/MWh and $65/MWh, respectively, in Q4 2024, up from $30/MWh in Q3 2020. Solar and wind PPAs both showed higher contracting prices in 2024 to reflect the twin impacts of higher costs (labor, panels) as well as meaningfully higher interest rates. We see supply chain and permitting constraints as lingering but remaining an overhang on near-term renewable development timeframes and returns. Utility scale solar and storage demand remains robust, although interconnection challenges have yet to clear meaningfully.

In April 2024 the Biden administration rolled out policies that increase tariffs on solar cells from China to 50% (more on this later). In response, many U.S. developers have stockpiled inventories of low-cost panels from south-Asian countries like Vietnam, Thailand, and increasingly India. U.S. developers can mitigate the impact of tariffs and potential snags around forced-labor and anti-circumvention/anti-dumping laws by sourcing domestic PV components, but such products bring a price premium. Meanwhile, the wind industry is still contending with challenges around land availability, community opposition, lengthy and arduous permitting and interconnection processes, and the price pressures remaining from pandemic-era inflation. Rising insurance costs resulting from increasingly common extreme weather events are adding cost pressures too.

Project delays are occurring across renewable technology types and regions for numerous reasons, typically interconnection issues, high voltage transformer (HVDC) access and lead times, permitting challenges, and module access and financing challenges. Delays on transformers broadly are now about three years, and delays for HVDC transformers are even more protracted.

We note that renewable PPA prices appear to be relatively sticky at their higher levels and we expect them to persist at these levels through 2025.

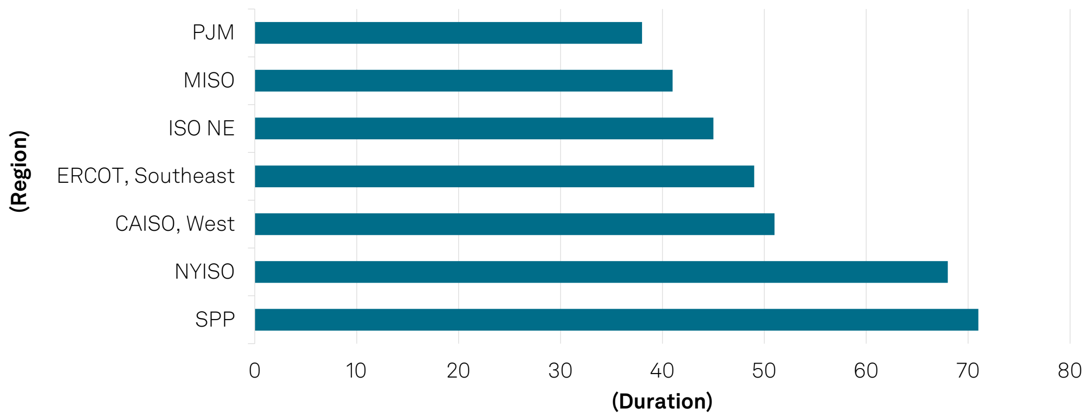
Demand cannot be met with renewables alone. The increasing need for reliable, uninterruptible power for electrification is not helpful for the sustainability story. Even as a meaningful amount of renewable power is being placed on the grid, we expect there will be significant need for natural gas-fired generation if this demand is to be addressed. Not only is gas generation needed to meet part of the demand, but dispatchable gas resources will also serve a critical balancing role as more renewable capacity enters the market.

There just are not enough renewable MWs to accommodate the demand increase, especially after incorporating their effective load carrying capability (ELCC) accreditation impact. That also means a substantial amount of MWs of gas-fired generation is needed. But this conundrum raises both a willingness and ability problem. A developer must be willing to take a 35-year directional bet on gas-fired generation in an environment pushing toward decarbonization goals (a priority for the outgoing administration).

Even if investors are somehow convinced to finance projects on the back of merchant energy revenues, new gas-fired entrants will also be delayed by the lengthy interconnection queue. Given poor results for recent new builds and weak economics, there have been no active interconnection requests for natural gas plants since 2021, a first since 1997. Besides, the expansion of transmission infrastructure assets is a long-term planning process that requires permitting and siting and is typically done at a measured pace. It requires regulatory approvals that often take many filings and considerable time. Moreover, reliance on foreign suppliers, lingering COVID-19 pandemic-related shortages, and insufficient domestic manufacturing capacity all contribute to delays in transmission project development. Given how pervasive transmission issues are, we believe, at least for now, it is all about securing generation sites that come with grid interconnection infrastructure. The time it takes for new generation capacity to go from planning to commercial operations has increased because grid interconnections are harder to find (see chart 9).

Chart 9

Interconnection queue by region



As of April 2024. Duration—Average time from queue data to proposed online date. Source: S&P Global Market Intelligence.

Competitive, long generation companies are well positioned to respond to the demand, and we believe Constellation Energy and Vistra Corp. are best positioned. We expect Talen Energy Corp. and PSEG Power LLC to benefit as well, but to a lesser extent because of their smaller generation footprints. We also expect developers such as NextEra Energy Inc., Brookfield Renewable Partners L.P., Clearway Energy Inc., and Pattern Energy Group L.P. to allocate significant capital to firming power. Pattern Energy's Sunzia project is well positioned because there can be no energy transition without transmission. This asset is under construction but needs to manage its construction costs within expected budget.

Main assumptions about 2025 and beyond

1. Path of renewable proliferation dominates power market forwards.
Renewable proliferation continues to have two drivers: 1) The need for energy to replace fossil plants retiring; and 2) a temporary increase in renewable PPA prices.

2. Supply chain bottlenecks to ease and domesticate.

Solar panel imports were delayed by geopolitical tensions and the implementation of the Withhold Release Order (WRO), the anti-dumping/countervailing duties tariffs (AD/CVD), and the Uyghur Forced Labor Prevention Act (UFLPA). In 2025 we expect the supply chain for solar panels, inverters, batteries, etc. to domesticate further.

3. The heightened risk of tariffs.

We think the increase in pricing of renewables PPA is already reflecting some of that risk.

4. Risks to provisions of the Inflation Reduction Act.

We see a surgical strike (provisions of the IRA) rather than a sledgehammer approach (full repeal) as likely. That is also the market consensus.

Path of renewable proliferation will slow in 2025. North America is poised to break its annual installations record for the second year in a row in 2024, touching the 50 GW mark for the first time, which represents a 30% year-over-year growth rate. Chinese overproduction since the passage of the IRA has flooded markets with inventory and caused average global module prices to plummet. For solar, prices have declined from $0.26 to $0.13/watt between the end of 2022 and now. Solar module inventory in the U.S. has surged over the past 18 months because of the global price collapse, resulting in nearly 50 GW of imports in 2023 and an additional 32 GW through July 2024. However, much of this inventory must be installed by the end of 2024 to avoid tariffs from the anti-circumvention investigation.

Since July 2024 the manufacturers in Vietnam, Thailand, Malaysia and Cambodia have largely halted shipments owing to the uncertainty surrounding potential tariff levels and the filing of an injunction. This injunction could trigger retroactive duties for modules shipped over the past three months if the Department of Commerce determines there was a spike in imports from these countries to circumvent future tariffs. Considering these challenges, some developers have delayed projects in 2025 and 2026 to seek alternative supply sources.

Overall, we expect solar installations to decline to about 40 GW in 2025.

Tariff risk has heightened. The first Trump administration's Section 301 review in 2017 led to tariffs on about $160 billion and $115 billion worth of Chinese products at rates of 25% and 7.5%, respectively, with additional measures under Sections 232 and 201. These tariffs, along with subsequent adjustments by the Biden administration, have reduced mainland China's share of U.S. imports from 21.1% in 2016 to 13.6% by September 2024.

While tariffs on products from China could go further up under the second Trump administration (and new ones imposed on Mexico and Canada), earlier in 2024 the Biden administration increased tariffs under Section 301. In particular, the administration increased the tariffs on electric vehicles (EVs) to 100% from 25%, solar cells to 50% from 25%, and lithium-ion batteries to 25% from 7.5% (EV batteries in 2024 and non-EVs in 2026).

Major developers have been planning on tariffs for over a year and have brought in much of the equipment they need for 2025 and 2026 projects. They are also moving increasing levels of their supply chain domestically. Some developers like NextEra have offloaded tariff risk for suppliers to bear. Finally, we note that global panel prices are now at all-time lows due to a glut of supply and improvements in the efficiency of manufacturing. However, there is a large gap between the prices in the U.S. and globally because of U.S. trade policy. As a result, there will still be potential for imports from China despite tariffs. We note that photovoltaic module prices have started to return to around $0.28-$0.32/watt for supply that is still shipping and baking tariff risk into current pricing.

Tariffs have an adverse effect on the declining cost curve of the renewable industry, slowing down growth plans of many companies. Perversely, this may help slow down growth and thereby benefit the credit profile of companies that have been aggressively utilizing debt-funded growth to take advantage of IRA tax credit provisions.

Potential repeal of sections of the IRA will likely weigh on investments. While the IRA is creating much more economic benefits in Republican states, the partisan nature of the IRA law and the need to pay for extending the 2017 tax cuts will likely result in some changes. We do not assume a sledgehammer-style full IRA repeal in our base-case but do assume a surgical strike across some provisions.

Even as we have not heard any credible calling for a broad-based repeal of any of the tax credits, we think an earlier end to premium tax credits/investment tax credits (PTC/ITC) could be a potential way to save money. The IRA increased the solar ITC to 30% from 26% and extended the credit through 2032 before stepping down to 26% in 2033 and 22% in 2034 and expiring in 2035. This ITC not only helps support incremental demand for renewables but has also become more relevant to installers and developers due to the transferability of the tax credits. The removal of these credits, should this occur, would weigh on demand through less advantageous project economics, as well as eliminate the ability of developers to monetize credits. However, it is more likely that downward revisions to the ITC would be contemplated rather than its elimination.

The consensus view in the market is that EV credits and offshore wind are areas most at risk. Given President-elect Trump's comments on offshore wind during the campaign, even if his administration does not consider outright removing wind subsidies, it is possible he can consider slowing down or halting development projects through an executive order to commence environmental studies. We see tax transferability (it has zero cost from a budget standpoint), and nuclear PTC are at least risk. That said, we note that transferability facilitates a broader arena for monetizing credits and repealing that would stunt growth, lowering future credits generated.

Wading further into the weeds, we do not see 45Q being as much of a target since this has a lot of Republican support and several traditional oil/gas firms (e.g. Chevron, Exxon) have been leaning into carbon sequestration. Our view is similar for 45X, the domestic manufacturing credits, since it supports largely manufacturing jobs domestically and in Republican districts (e.g. Ohio).

We do note that most of the large developers have safe harbored equipment for their backlogs so that they would be protected from an early end to credits. Safe harbor only requires about 5% of the project cost to be locked up (or construction to commence) and is typically good for four years. An early end to credits could initially create a wave of demand to beat the end date but then a big slowdown would likely follow.

Credit metrics and financial policy

Power prices have stayed strong because of rising demand and slower-than-expected increase of renewable generation. We note that debt reduction is still a stated objective for several IPPs. In 2021, expectations for aggregate debt/EBITDA and FFO to debt were above 4.0x and 15%, respectively. Now some IPPs have targets of adjusted det to EBITDA in the 2.50x-2.75x range and adjusted FFO to debt above 25% on a sustained basis by year-end 2025. We see tailwinds for the credit profile for the sector with more ratings at investment grade levels potentially by year-end.

Key risks or opportunities around the baseline

1. Excess cash allocation to organic growth.

We see companies deploying significant proportion of excess cash to organic investments and acquisitions. However, share buybacks continue to be a priority in 2025.

2. Interest rates will likely decline by year-end 2025.

Many companies kept operating and maintenance costs flat or down in recent years, with labor attrition and technology advances offsetting inflation. However, material costs could increase with tariffs, and supply chain shortages could influence margins in 2025.

3. Long-term contracts with large loads can improve cash flow.

While hyperscalers have focused on contracting clean energy that also offers scale, other large loads could pursue contracts with gas-fired generation for their needs.

We expect to see increasing levels of excess cash allocated to organic growth. We see a potential pivot away from share repurchases in 2025 towards growth capex. While some of its provisions could face repeal, we think the IRA provides incentives for renewables that have led some of the manufacturing base to return to the U.S. Not unexpectedly, we continue to see significant deployment of capital in new storage and renewable projects. What interests us more is the level of capital spending that companies will direct towards repowering the wind fleet. With several installations getting to their decade-old vintage, we see the repowering of wind assets as a necessity, not an option.

Interest rates will likely decline in 2025 but still present a challenge. With uncertainties relating to the expected tax cuts and growing risk of fiscal deficits, yields on 30-year treasuries reversed course and increased in recent weeks. We expect interest rates to continue to slow acquisitive growth in the sector. In particular, the Yieldco segment is heavily dependent on rates because of the need for external financing of their growth. We expect this segment to continue to lag growth expectations until rates start declining. While companies like AES corp. and NEP are contending with growth and equity needs, a company that has managed its growth relatively well is Clearway Energy. We think rising cash flow available for distributions (CAFD) and increasing internal cash flow retention limits its need for future equity.

We expect more bilateral, long-term contracts that can benefit cash flows. We have not assumed any hyperscaler contracts in our forecasts for companies such as Constellation Energy but provide some details for context. If we assume a floor price of about $45/MWh (a generator would argue they are assured of that in the wholesale market through the production tax credits, and a hyperscaler must match it) and convert the latest $270/MW-day capacity price into $/MWh at 95% capacity factor ($12.5/MWh), then add ancillaries and a premium for clean attributes and long-term contracting, we believe these PPAs would be struck at $80/MWh-$85/MWh. Also, the longer the term, the higher the price would likely be.

While nuclear assets are in the news, we think this could expand to natural gas assets. Gas fired generation provides dispatchable but not clean energy. We think many data centers' sponsors will simply ignore the sustainable part.

A recent issue has been FERC's recent order rejecting Talen Energy's amended ISA to serve Amazon Web Services' data center co-located with the Susquehanna nuclear unit. The order effectively slows down behind-the-meter colocations. However, in later November Constellation submitted a fast-tracked 206 filing arguing that the PJM tariff does not contain rules for interconnected generators to follow when seeking to provide service to fully isolated co-located load, and asked FERC to adopt a replacement rate that incorporates PJM's previously established guidance on co-located load.

We expect power prices to be range bound in 2025, but most companies are heavily hedged. We note that forward power prices have held steady despite a decline in natural gas forwards, suggesting higher demand that has increased market heat rates. The forward gas curve is still in contango but now well below $4.0 through 2026 with broad delays in liquid natural gas (LNG) supply projects as well as a mild start to the winter, pushing inventories higher. While ERCOT power is down modestly, spark spreads in the region have remained resilient and expanded as power usage has increased. For instance, earlier this year in its capacity, demand, and resource (CDR) report, ERCOT laid out negative reserve margins after factoring noncontracted load. With likely acceleration of demand in 2025-2026 and limited new gas generation in the queue, we see a strengthening power demand for generators such as Vistra Corp. and Calpine Corp. Regional natural gas demand should increase in 2027 with the latest round of LNG supply reaching in-service as adding to energy price expectations. The pressure from coal-fired retirements and reliability needs also helps power prices nearer-term.

The increase in renewable PPAs should also buttress prices. PJM's congested interconnection queue is adding uncertainty and pushing prices up in the market. Rising land and labor costs have been reported across most markets, adding to projects' capex—costs that developers are largely passing forward in PPA prices. Industry headwinds make it unlikely PPA prices will go down substantially anytime soon. At the same time, buyer demand for PPAs remains high due to pressure on corporations to decarbonize their energy usage.

Related Research

- Data Centers: Surging Demand Will Benefit And Test The U.S. Power Sector, Oct. 22, 2024
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- Power Sector Update: Credit Drivers In The California And Texas Power Markets, June 18, 2024
- Power Sector Update: A Rising Tide And Other Credit Views, June 10, 2024
- Power Sector Update: The Piper At The Gates Of Dawn, Apr. 1, 2024