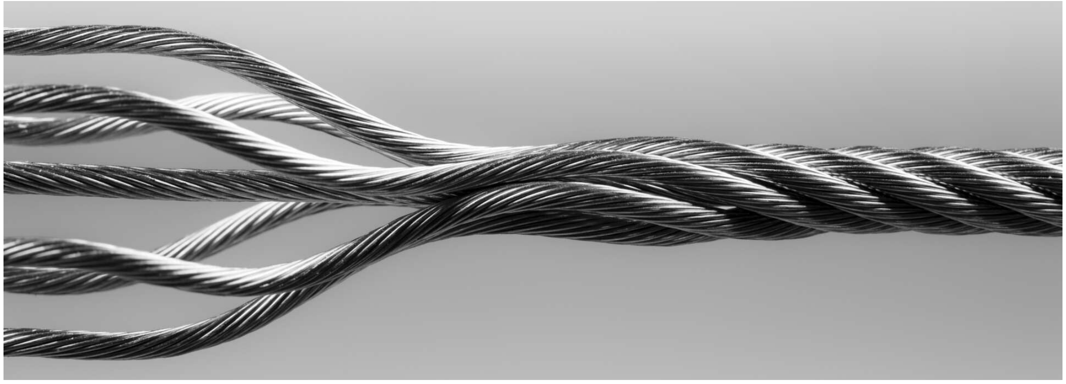
S&P Global Ratings

North America Merchant Power

Electrification will fuel fundamentals in 2024

January 9, 2024

This report does not constitute a rating action.



What's changed?

Renewables deployment slowed. Interest rates and supply chains slowed wind deployment in 2023. Solar growth continues but was rendered ineffective in some regions without commensurate batteries/storage deployment.

Power prices have come off 2022 highs but spark spreads remain surprisingly tenacious. While supply from the Permian and milder winters have brought down natural gas and power prices, demand has stayed strong and has grown from electrification of some sectors, and also from extreme weather. Texas is a standout zone as it relates to demand.

Nuclear power tailwinds grow stronger. As expected, some asset rationalization occurred in 2023. The Inflation Reduction Act (IRA) provides strong support for existing nuclear and highlights nuclear's role in successful decarbonization.

What are the key assumptions for 2024?

Continuing coal plant retirements. Despite temporary delays due to resiliency concerns, structural factors weigh heavily against the coal fleet. A slew of regulations are coming.

Stable ratings profile. Unregulated power companies have significant excess cashflow and high cashflow conversions. Some are transitioning and may underperform if strategies go awry.

What are the key risks around the baseline?

Grid resiliency. With baseload supply shrinking and electric vehicles fueling demand, renewables/storage additions will need to scale up quickly to preserve reliability.

Battery and hydrogen scaling. Subsidies should lead to a meaningful scaling in California and ERCOT, and dampen expectations for scarcity prices, but implementation concerns persist.

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Ratings Trends: North America Merchant Power

Chart 1

Ratings distribution

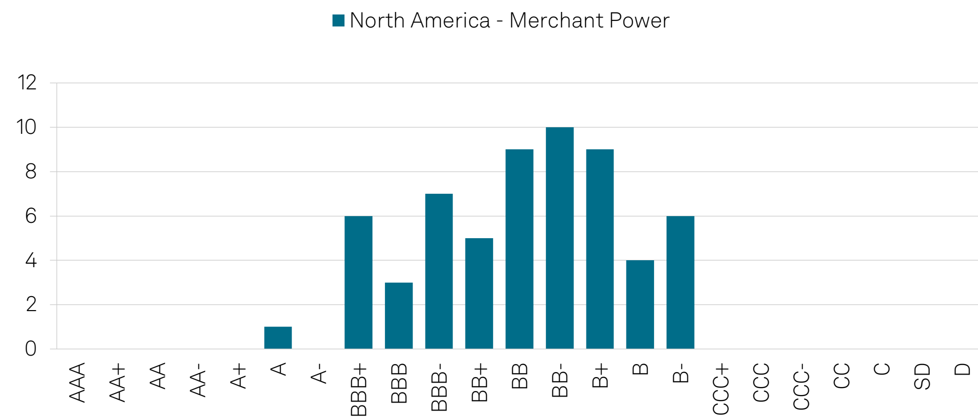


Chart 2

Ratings outlooks

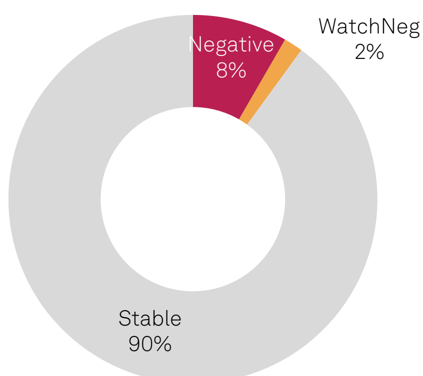
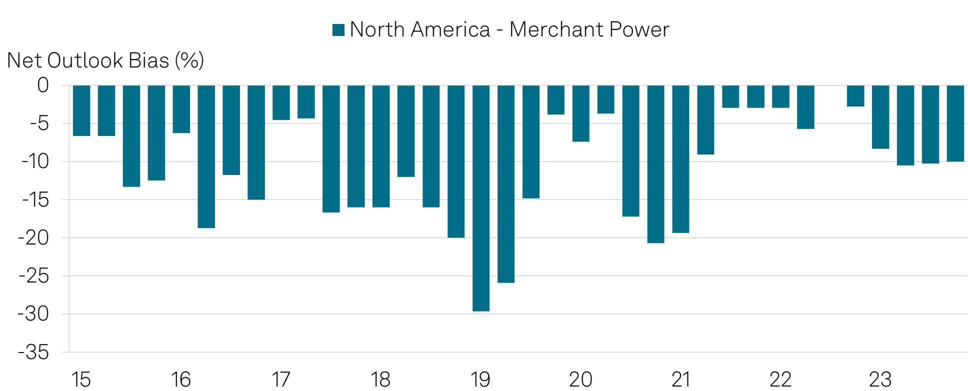


Chart 3

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 stable ratings of renewable portfolios and consolidation in the industry. Our investment-grade credit quality has also strengthened, which had faced deterioration over the past three years. Negative outlooks, which had declined to 3% at end 2022, picked up marginally to 6%, but stay persistently below levels in the past (15% as of Dec. 2021 and 24% in Dec 2020).

Industry Credit Metrics: North America Merchant Power

Chart 4

Debt / EBITDA (median, adjusted)

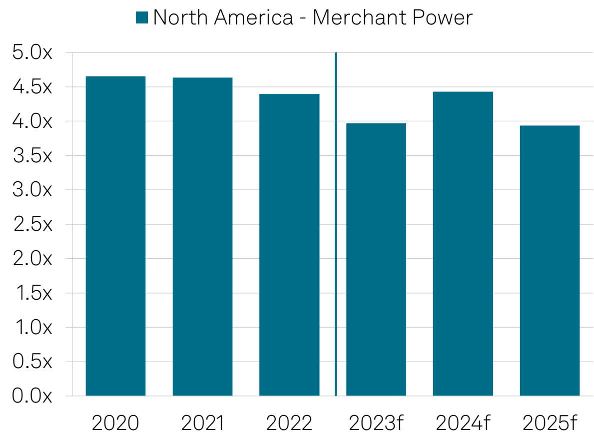


Chart 5

FFO / Debt (median, adjusted)

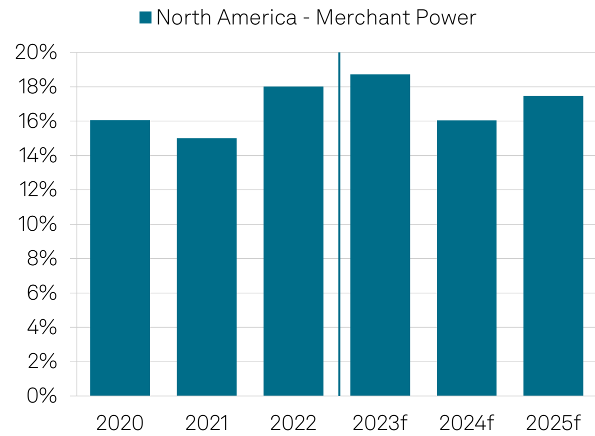


Chart 6

Cash flow and primary uses

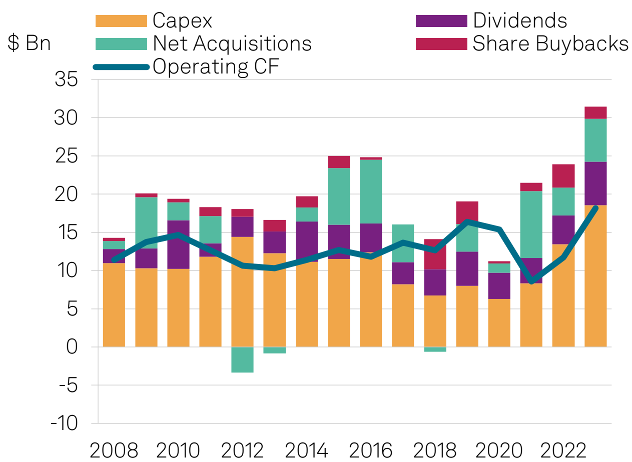
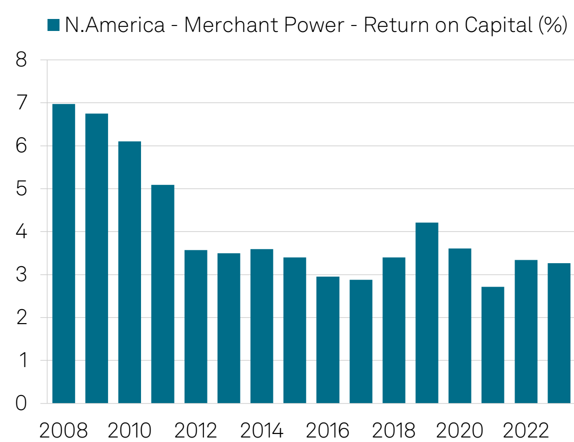


Chart 7

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 (2023) figures for cash flow and primary uses and return on capital employed use the last 12 months' data.

Entering 2023 we expected financial ratios to marginally deteriorate even as companies were amortizing or paying down debt. But winter events caused outages and slowed deleveraging efforts of major independent power producers (IPPs), and some IPPs have slowed their investment-grade aspirations, choosing instead to reallocate excess cashflow to share buybacks and/or acquisitions. Debt reduction still remains the stated objective for a number of IPPs, but most still target adjusted det to EBITDA in the 2.5x-2.75x range and adjusted funds from operations (FFO) to debt above 25% on a sustained basis. In contrast, two years ago, expectations for aggregate debt/EBITDA and FFO to debt were above 4.0x and 15%, respectively.

The one segment facing incremental leverage increases are the Yieldcos because of higher interest rates and a significant erosion in their share prices. Growth will be harder for these companies until interest rates moderate.

Industry Outlook

Ratings trends and outlook

1. Renewables PPA prices have nearly doubled since first quarter 2021.

Solar and wind power purchase agreements (PPAs) both showed higher contracting prices in 2023 to reflect the twin impacts of higher costs as well as meaningfully higher interest rates.

2. The nuclear renaissance is here to stay.

The IRA introduced nuclear production tax credits (PTCs), which supports nuclear power prices and plant economics through 2032.

3. Stable ratings profile.

We expect robust cashflow generation and high cashflow conversion, provided operating performance remains intact.

Renewables PPA prices have nearly doubled since first quarter 2021, temporarily stalling the downward cost curve of power prices. We note that renewable PPA prices appear to be relatively sticky at their higher levels. Solar and wind PPAs both showed higher contracting prices in 2023 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 stubbornly persistent and 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.

Project delays are occurring across renewable technology types and regions for numerous reasons. Typically, these are 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 see this as most challenging for larger projects like offshore wind.

Also, while on the economics of projects, with the IRA expanding tax incentives, we expect some shift to the solar 10-year PTC over the investment tax credit (ITC). This will be dictated by the capacity factor of the development project. In particular, projects with weaker economics could continue to utilize ITCs. For example, if a project has a relatively high capital cost and low capacity factor, the ITC would be more economical.

The nuclear renaissance is here to stay. We expected consolidation in 2023 and more could still come. It was only three years ago that nuclear plants were economically beleaguered and retirements were being announced. We see the PTC provisions in the IRA as a game changer for merchant nuclear power. The IRA introduced nuclear PTCs, which supports nuclear power prices and plant economics through 2032, mitigating the risks that nuclear plant value will return to uneconomic levels when power prices eventually decline. The PTCs change the model for unregulated nuclear power generators from a merchant business to a nine-year contracted business, with floor pricing of $40/MWh to $44/MWh.

Moreover, starting in 2025 the maximum PTC and gross receipts threshold are subject to an inflation adjustment based on the GDP price deflator for the preceding calendar year. Also, the maximum PTC is rounded to the nearest $2.5/MWh and gross receipts threshold is rounded to the nearest $1.0/MWh. We note the phase-out price can change significantly depending on the assumed inflation rate. In particular, the rounding off to the nearest $2.5/MWh can increase the phase-out price significantly, offering unregulated nuclear a meaningful upside in EBITDA (see table 1). We see these developments as credit favorable for generators like Constellation Energy.

Table 1

Production tax credits math

	2% inflation					3% inflation				
	Maximum PTC		Gross receipts threshold		Phase out	Maximum PTC		Gross receipts threshold		Phase out
	Inflation	Rounded	Inflation	Rounded		Inflation	Rounded	Inflation	Rounded	
2024	15	15	25	25	43.75	15	15	25	25	43.75
2025	15.3	15	25.5	26	44.75	15.45	15	25.75	26	44.75
2026	15.61	15	26.01	26	44.75	15.91	15	26.52	27	45.75
2027	15.92	15	26.53	27	45.75	16.39	17.5	27.32	27	48.88
2028	16.24	15	27.06	27	45.75	16.88	17.5	28.14	28	49.88
2029	16.56	17.5	27.6	28	49.88	17.39	17.5	28.98	29	50.88
2030	16.89	17.5	28.15	28	49.88	17.91	17.5	29.85	30	51.88
2031	17.23	17.5	28.72	29	50.88	18.45	17.5	30.75	31	52.88
2032	17.57	17.5	29.29	29	50.88	19	20	31.67	32	57

PTC—Production tax credit. Source: Constellation Energy.

Recent capacity price formations in key markets are increasingly reflecting the cost of reliability. Capacity prices for New York City (NYC), or the New York Independent System Operator (NYISO) Zone J, which were at historically low levels for summer 2021 and 2022, have rebounded in the last two auctions that procured capacity for summer 2023, as well as winter 2023/24, clearing at $17.75/kW-month and $12.90/kW-month, respectively.

A key driver for higher capacity prices is the first wave of retirements for generators affected by the Peaker Rule. As of May 1, 2023, about 1 GW of peaking plants deactivated or limited their operations to comply with the rule, removing critical supply resources from a region that has near negligible incremental generation solutions in the near-to-medium term. While an additional 590 MW of capacity was scheduled to be offline beginning in May 2025 to comply with the Peaker Rule, NYISO has recently announced that this peaking capacity must remain in service beyond their anticipated deactivation dates, albeit temporarily, for reliability purposes.

We expect market conditions to remain tight until at least 2026, which is when we expect the Champlain Hudson Power Express (CHPE)--a 1.25 GW transmission project that imports hydro power from Quebec to NYC--to come online. We also note that CHPE is a summer-only resource (since Quebec is a winter peaking region), meaning it will likely not be able to deliver power during the winter months, which could put upward pressure on winter capacity prices. In earlier commentaries on offshore wind (see Related Research) we have already noted risks to offshore wind projects on the eastern seaboard. Cumulatively, the expected generation output of these at-risk offshore projects, if completed, would represent about 25% of NYC's annual energy demand in 2023.

We believe the positive momentum around capacity prices in the NYISO Zone J is sustainable at least over the next two to three years, if not beyond. This view is largely predicated on the structural makeup of this market, which continues its high level of dependency on thermal generation that is physically located in, or is interconnected to, NYC, with very little power import options.

Our capacity price forecasts for NYISO Zone J place summer 2024 and 2025 around $16/kW-month, with the winter 2024/2025 price around $12/kW-month. Our long-term capacity price for summer (starting 2026) is $12.5/kW-month, and winter 2025/2026 is $6.5/kW-month, though this price moderation could easily shift back by 2-3 years, depending on the progress that is made on CHPE and offshore wind projects.

The Pennsylvania, New Jersey, and Maryland area (PJM) remains an outlier for now. Capacity prices in the past three auctions have declined consistently to uneconomic levels for new build. In addition to the retirements that we noted elsewhere in this commentary, the regional transmission organization (RTO) also projects demand growth of about 1.4% per year in its service territory over the next decade, largely driven by electrification needs. In some individual zones, we forecast PJM load growth to be as high as 7% per year.

On the supply side, the interconnection queue consists primarily of renewables (94%, 290 GW). The historical completion rate of renewable generation resources in the PJM has also been very low, at 5%, which if unchanged would lead to retirements outpacing new entry. Under its low-renewable-entry scenario, PJM estimated that its reserve margins could decline to as low as 5% (from 23% currently). All of these factors lead to a logical conclusion that capacity prices will need to rise, and materially, to ensure reliability is not put at further risk. The novel Capacity Performance Quantifiable Risk (CPQR) scheme should also result in higher clearing prices.

We expect RTO, the Mid-Atlantic area (MAAC), and the Eastern Mid-Atlantic area (EMAAC) to clear around $45/MW-day, $75/MW-day, and $75/MW-day, respectively, for the 2025-2026 auction. The historically constrained eastern PJM could see more upside than the broader clear price. MAAC and EMAAC have cleared modestly but forthcoming retirements with long-term transmission and storage replacements present an upside opportunity. The rated companies with sizable PJM footprints are Vistra Corp., Calpine Corp, Constellation Energy, PSEG Power, and Talen Energy.

Main assumptions about 2024 and beyond

1. Divergence in strategies.

We see the emerging pure-play theme as consistent with companies increasingly diversifying to gain exposure to electrification, renewables, retail, or hydrogen. We see most companies doubling down on emission-free generation, while some companies may pivot away from generation altogether.

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 2024 we expect the supply chain for solar panels, inverters, batteries, etc. start to domesticate given the favorable subsidies. Transformers continue to dominate equipment supply shortages, while inverters have under-performed.

3. Path of renewable proliferation dominates power market forwards.

Renewable proliferation continues to have two drivers: 1) The need for energy to replace uneconomic fossil plants retiring; and 2) a temporary increase in renewable PPA prices. Even as cost curves were declining, renewable PPA costs changed course and have nearly doubled since first quarter 2021 due to higher financing costs and continuing supply chains disruptions.

Coal-fired generation got a reprieve but we expect retirements to ensue in 2024. In 2022, against the run of play, tightness of generation supply pressured utilities in the Midwest-ISO (MISO) to extend the retirement dates for several coal plants, including Alliant's Edgewater and Columbia and WEC Energy's Oak Grove retirements being pushed to 2025/2026.

However, in March 2023 the Environmental Protection Agency (EPA) finalized its latest "good neighbor" policies, via its Cross State Air Pollution Rules (CSAPR), setting nitrous oxide (NOX) levels that become more stringent in 2026 and move away from "banking allowances" by 2030. The EPA estimates this could drive 14 GWs (13%) of the current coal fleet to retire by 2030. However, with effluent limitations guidelines (ELG) and coal combustion residuals (CCR) regulations to follow, we think a next large wave of coal-fired retirements by 2027 is likely.

No incumbent utility or power generator is investing new money in coal generation units or coal mines. Coal units are increasingly under-maintained and, with Eastern coal prices moving higher, the economics of coal-fired generation is deteriorating. Rising labor wages, property tax bills, and still-lofty coal prices in the East point to further pressures.

Bottom line, coal retirements will continue, particularly in the PJM region, where capacity clearing prices are too low to keep coal-plants economical and where we forecast at least 24 GW of policy-related retirements. We think the rules that contribute to the largest requirements include about 6.0 GW related to the Illinois Climate & Equitable Jobs Act in 2030, about 4.5 GW in 2026 for EPA's CSAPR rule, 3.5 GW from EPA's ELG in 2028, 2.5 GW from EPA's CCR guidelines in 2027-2028, and 2.5 GW from New Jersey's carbon dioxide rule.

As of November 2023, about 135 GW of U.S. grid-connected coal-fired capacity that existed in 2010 has retired. Another 75 GW have been committed or proposed to retire by 2030. The Midcontinent and PJM regions have the most announced retirements.

We expect U.S. solar Installations to be strong in 2024, despite continuing supply chain constraints. A combination of higher polysilicon and steel prices--that nearly doubled and tripled, respectively--as well as an anti-dumping investigation by the Department of Commerce (DoC), and the implementation of the UFLPA all contributed to stymie growth in 2022 and delay project constructions into 2023 and 2024. Suppliers largely stopped shipping modules into the country during second and third quarters of 2022, but the situation has improved markedly since then.

Our affiliate, IHS Market, estimates that total module imports for the first seven months of 2023 into the U.S. were 28.2 GW, which is already more than the total imports for the full year in 2022. This indicates that module availability has not slowed project development in 2023, leading to an expected doubling in utility-scale solar installations year-over-year.

In August 2023, after an investigation that lasted more than a year, the U.S. DOC confirmed that five companies were circumventing antidumping and countervailing duties. We note that President Biden’s 24-month tariff moratorium protects modules that are imported before June 2024 and consumed before Dec. 3, 2024, which will likely drive installations in the U.S. to about 40 GW in that year. However, once the AD/CVD tariff moratorium expires, the market will temporarily decline because the U.S. depends on Southeast Asian manufacturers for modules, who supplied almost 80% of the market in 2022. We expect installations to pick up once domestic manufacturing scales up in 2026 because of the 10% domestic content bonus.

As a result, project delays will likely be the key determinant for market growth in 2024 and 2025. That said, most companies remain bullish about long-term prospects while acknowledging the realities and pressures of a higher cost of capital.

A tightening electric grid will increasingly value resiliency in 2024. We see reliability risks as the renewables transition accelerates. We've seen reliability issues in the California Independent System Operator (Cal-ISO) and ERCOT regions each year since 2020, because baseload plants have been retired and replaced with intermittent renewables. In our analysis, the Cal-ISO pointed to the potential for 1.7 GW-1.8 GW supply shortage across 2022-2025 in extreme load scenarios even when accounting for its 11.5 GW new resource target. To illustrate the pressures on the grid: on Aug. 14, 2023, Cal-ISO declared a regional transmission grid early emergency alert (EEA) due to high demand and high exports to the desert Southwest. On this day, solar generation declined from a high of 15.5GW at 12:30 pm to less than 0.5 GW by 7:30 pm, requiring gas-fired peaking generation to scramble and plug the drop. In response to the increasing baseload shortage, California has pushed out the closure of the Diablo Canyon nuclear plant by an additional five years from its previously planned shutdown of 2024-2025.

Resource adequacy (RA) prices in Cal-ISO are reflecting the shortage. The worsening of the now notorious "duck curve" has placed emphasis on dispatchable resources, especially natural gas-fired plants, which can quickly ramp up their production to meet demand. This situation also raises an economic challenge, as the less opportunity dispatchable resources have to sell energy into the grid during a day, the less financially competitive they become, which, if unmitigated (for example, via an increase in RA prices), would ultimately lead to shutdowns and retirements.

Another driver that is affecting generation supply in Cal-ISO is the impact from once-through-cooling (OTC) compliance rules, which will remove nearly 4.5 GW of valuable dispatchable capacity from the RA market at the end of 2023. Some portion (about 833 MW) of this capacity will permanently retire, with the remainder being put into CAISO's Strategic Reserve until Dec. 31, 2026, and will only be called upon under extreme events (e.g., heat waves). Reacting to these factors, RA prices in Cal-ISO have risen substantially over the past two-years and are now at unprecedented levels. Aggressive California Public Utilities Commission (CPUC) clean capacity procurement orders and potential non-compliance penalties support strong recourse adequacy prices in the near term. We expect RA prices in the region to be about $10/kW-month through 2030s, compared to RA prices of around $2.5/kW-month, or lower, as recently as 2018.

Meanwhile, electricity demand this summer in ERCOT was well above 2021 and 2022 levels. Each month saw record demand, with August reaching a peak of 85 GW. Still, Texas experienced below-average power outage activity since July. ERCOT has previously warned of 8 GWs of coal shutdowns. As a result, scarcity events have seen meaningful price surges. ERCOT is also at risk of seeing a pronounced California-like duck curve in 2024.

In the PJM we see 40 GWs of retirements between 2022-2040, 60% of which is likely coal-fired. That compares with only 15 GWs of new capacity that we expect to see come online on an effective capacity-adjusted basis (given the majority is renewables). If we add the quickly ramping load growth of 10 GW to 15 GWs driven by data centers and EVs, the PJM could see potential single-digit reserve margins by 2028.

Bottom-line, with baseload supply shrinking and increase in demand from data centers and electric vehicle adoption, renewables/storage additions will need to scale up quickly to preserve reliability. As a sidebar, we note that demand from data centers--which some market participants expect to increase to 7.5% of national electric usage in 2030--could alone meaningfully influence power prices (current usage is about 70 million MWh, or about 2% of national demand).

Offshore wind continues to see a tough environment. We see offshore wind as challenged in the U.S. due to inflation and supply chain pressures and high cost relative to legacy generation. The industry markers we are monitoring in 2024 are the potential for utility sponsors exiting projects, attempts to restructure contracts that were struck in the 2018-2022 timeframe, and progress on frontrunning projects.

Specifically, in 2023 Ørsted canceled Ocean Wind 1 & 2 (2.2 GW in New Jersey) largely on supply chain issues, specifically a delay in monopiles that caused delay. The project was originally targeted for 2025 before the company delayed it to 2026. However, the lack of vessel availability under the new timeframe would have led to recontracting with vendors at significantly higher costs. In Maryland, Ørsted has indicated that Skipjack 1-2 (965 MW) are being reconfigured and likely to be delayed to at least 2026.

Meanwhile, in October, New York utility regulators denied requests to increase the amount of money New Yorkers would have to pay under existing contracts for power to be produced at four offshore wind projects under development. The developers had cited higher inflation, interest rates, and supply chain issues putting final investment decisions (FID) at risk unless inflation and interconnection cost adjustment mechanisms are incorporated into the contracts. The companies said they are reviewing the New York decision before taking next steps on their projects (Ørsted's 924 MW Sunrise Wind, and Equinor/BP's 816 MW Empire Wind 1; and 1,230 MW Beacon Wind). On Jan. 3, 2024, BP and Equinor announced the cancellation of Empire Wind 2 due to cost pressures.

In October 2023, New York state also released the winners of its latest renewables auction (Round 3) that resulted in conditional awards for new offshore wind projects. The New York State Energy Research and Development Authority (NYSERDA) selected three offshore wind projects totaling about 4.0 GW, targeted for a 2030 in-service date. We expect the contracts to be for 25 years, similar to those in Rounds 1 and 2. Notably, the nominal weighted average strike price of about $145.0/MWh is significantly higher than cleared prices for winners in Rounds 1 and 2. New York also initiated the process for an accelerated offshore wind auction, with NYSERDA issuing a request for interest (RFI). An accelerated auction could give earlier round projects a path to cancel the current lower-priced contracts and rebid, as seen in other states. We expect any such moves to result in cancellation fees, both from New York state and the vendors. Because of the reset, the commercial operations dates (COD), which currently are between 2025 and 2028, will also be delayed. We have noted elsewhere in this commentary that these at-risk projects are resulting in higher prices in recent New York capacity auctions.

Despite the setbacks, some projects are pushing forward. Ørsted has made the FID, commenced Revolution (704 MW, in CT/RI), and maintained its 2025 commercial operations date target. If on time, Revolution will be the second-largest offshore wind farm to be in-service behind Avangrid's Vineyard Wind, which we expect to see completely operational in 2024. As of Jan. 4, 2024, five of the 62 turbines were installed and the first one had delivered about 5 MWs of power to the Massachusetts grid.

Meanwhile, Dominion's regulated Coastal Virginia Offshore Wind project (CVOW; 2.6 GW) appears to be on track for 2026. The project has a regulator-approved $9.8 billion budget, with up to $10.3 billion deemed recoverable subject to prudency review; and a 50/50 cost sharing up to $11.3 billion.

Finally, we are watching Siemens Gamesa’s ability to meet future turbine contracts. Several offshore wind projects across the globe are slated to use Siemens Gamesa turbines this decade. These include Ørsted/Eversource's three projects totaling about 1.75 GW, and Dominion Energy’s CVOW, which plans to use 176 14.7 MW turbines.

Up in the Great White North, conflicting positions emerge regarding the energy transition. The government of Canada remains very focused on reducing its targeted greenhouse gas emissions through its proposed Clean Electricity Regulation. While most of Canada’s power grid is non-emitting, provinces more reliant on carbon fueled generation have been pushing back. Their concerns range from the lack of incentives for further natural gas generation to the ability to maintain a stable grid. The government of Alberta recently invoked the Sovereignty Act for the first time, which could be very meaningful. Similarly, the government of Saskatchewan is also looking at no longer collecting the federal carbon levy on electric heat.

At the same time, the power market in Alberta is still transitioning towards lower carbon footprint generation. This should be achieved by having more efficient natural gas-fueled assets and greater renewable penetration. Like other power markets, AESO has highlighted grid reliability as a key concern, with the government pausing the development of further renewables for six months.

In terms of pricing dynamics in Alberta, power prices continue to be very high, with an average of C$150/MWh for 2023, in line with 2022 prices. This was largely due to a combination of factors, including lower supply due to offline facilities, elevated natural gas prices, rising carbon pricing, and load growth. Both Capital Power Corp. (CPC) and TransAlta Corp. have benefited from those robust prices through their merchant exposure. As a result, both companies have made multiple acquisitions over the past year: CPC acquired the La Paloma facility and 50% interest in the Harquahala facility, while TransAlta acquired the remaining public float of TransAlta Renewables Inc. and the entire business operations of Heartland Generation Ltd. We view those acquisitions as modestly strengthening their overall fleet.

Credit metrics and financial policy

We expect ratios to strengthen from levels we expected in 2022 and 2021, despite unprecedented prices in first half 2022, partly because several companies were negatively affected by weather events like Winter Storm Uri and Elliott that slowed deleveraging plans. However, pricing has 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 a number of IPPs. In 2021, expectations for aggregate debt/EBITDA and FFO to debt were above 4.0x and 15%. 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 2024.

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 will continue to be a priority in 2024.

2. Interest rates will likely decline by year-end 2024 but still present a challenge.

Many companies successfully kept operating and maintenance costs flat, to declining, in recent years, with labor attrition and technology advances offsetting inflation. However, as materials costs stay elevated, these pressures will influence margins in 2023.

3. Supply chain remains disrupted but improving.

With supply of key components still disrupted, focus will be on other avenues of cost reduction. We expect companies that seek to improve their credit profile would continue to cut costs.

We expect to see increasing levels of excess cash allocated to organic growth. We see a potential pivot away from share repurchases in 2024 towards growth capex. 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 a number of installations getting to their decade-old vintage, we see the repowering of wind assets as a necessity, and not an option.

The IRA also increases the value for dedicated storage of CO2 in the power industry to $85/ton, up from $50/ton. The lower capture thresholds--18,750 tons/year instead of 500,000 tons--will expand the number of projects eligible for the tax credits. As a result, we see a spending increase on carbon capture, especially after the U.S. Department of Energy (DOE) Office of Clean Energy Demonstrations (OCED) announced up to $890 million in funding for three projects late December. Coincidentally, on the same day, the Environmental Integrity Project (EIP) issued a report that concludes that the laws and regulations governing the technology are still being developed, and the existing framework is weak to ensure that large-scale sequestration will deliver on the carbon reductions they promise.

Interest rates will likely decline in 2024 but still present a challenge. 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.

We expect lower power prices in 2024 compared to 2023, but most companies are heavily hedged. Natural gas has declined sharply since the start of November 2023, and is down 35%, 19%, and 16% since the start of 2023 for years 2024, 2025, and 2026, respectively. The forward curve is still in contango but now well below $4.0 through 2026. Driving the natural gas move is rising production on better rig efficiency and milder winter weather, pushing inventories above the five-year average level of supply. Commensurate to this decline, power prices have declined too: PJM spark spreads are down about 17% for 2024 and 2025, and about 12% for 2026. While ERCOT power is down modestly, spark spreads in the region have actually remained resilient and expanded as power usage has increased. For instance, demand has been exceptional in ERCOT (incremental 10 GW over past two years). With likely acceleration of demand in 2025-2026 and limited new gas generation in the queue, we see a strengthening unregulated power demand for generators such as Vistra Corp. and Calpine Corp. Regional natural gas demand should increase in 2027 with the latest round of liquid natural gas (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' capital expenditures--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

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