

WEEKLY INTELLIGENCE BRIEFING

PowerAether Intelligence

Regulatory & Grid Intelligence for Data Center Developers & Operators



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THIS WEEK'S FOCUS

FERC's expected large-load jurisdiction ruling lands amid a proliferating patchwork of state tariffs — 77 now pending or in place — as BTM power becomes a structural feature of data center development, not a workaround.

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SECTION 01

Regulatory Radar — Federal

FERC | PJM Co-Location Tariff Compliance | Dockets EL25-49-000, RM26-4-000

■ HIGH IMPACT

PJM submitted its first compliance filing on January 20, 2026 and co-located load tariff revisions on February 23, 2026, in response to FERC's December 18, 2025 order (EL25-49-000). On April 16, 2026 — one day before this issue — FERC partially accepted and partially rejected PJM's compliance filing: it rejected PJM's proposed revision to the Co-Located Load definition and directed a further compliance filing due May 18, 2026. Separately, FERC announced it will act on the ANOPR (Docket RM26-4-000) by end of June 2026 — approx. 60 days beyond DOE's original April 30 deadline.

Mechanism Affected PJM Tariff, BTMG (Behind-the-Meter Generation) rules; co-location interconnection conditions. See: daypitney.com · blankrome.com

Next Milestones PJM further compliance filing due May 18, 2026 (EL25-49). FERC ANOPR action (RM26-4-000) by end of June 2026. BTMG transition period ends December 18, 2028. See: natlawreview.com · troutmanenergyreport.com · ferc.gov

Developer/Operator Impact: Projects structuring co-location arrangements with generation at PJM sites must model four distinct transmission service paths with materially different cost and curtailment risk profiles. Execution of co-location contracts before PJM's May 18 compliance filing and the subsequent FERC rate order should include change-in-law and cost-reopener protections. Existing BTMG arrangements have a transition period; confirm grandfather status with interconnection counsel.

Sources: ferc.gov (EL25-49, RM26-4-000) · natlawreview.com · troutmanenergyreport.com · daypitney.com

FERC Jurisdiction: State PUC Pushback on Large Load Interconnection

■ WATCH

State public utility commissions are actively resisting FERC's assertion of jurisdiction over the interconnection process for large loads, arguing federal overreach into retail regulatory authority. The Federal Power Act's jurisdictional divide — FERC over wholesale/transmission, states over retail sales and rate design — is the core battleground. Resolution will determine whether FERC can impose uniform large-load interconnection standards or whether the current 77-tariff patchwork across 36 states becomes the permanent landscape.

Developer/Operator Impact: If FERC jurisdiction is affirmed, expect more standardised interconnection timelines and cost allocation nationally. If jurisdiction is denied, state-by-state tariff negotiation remains the only path. Reflect this binary outcome in project underwriting scenario tables.

Sources: latitudemedia.com · ferc.gov · akerman.com

SECTION 02

State & Provincial Regulator Watch

Active large-load tariff terms — approved or pending Q1–Q2 2026. Source: SEPA DELTa (sepapower.org/large-load-tariffs-database) · utilitydive.com

State / Utility	Term	Min. Demand Charge	Collateral	Exit Fee	Status
CO / Xcel Energy	15 yr	80% contracted demand	6 months ops	Sum of remaining min. monthly bills	Pending PUC
VA / Dominion (GS-5)	14 yr	85% T&D / 60% gen.	\$1.5M/MW	>20% reduction triggers fee	Proposed SCC
OH / AEP Ohio	12 yr	85% contracted demand	Not disclosed	Steep; formula not public	In Force Jul 2025
CO / Tri-State G&T	15 yr	Min. energy + demand	\$2.7M/MW ■	Defined in tariff	FERC Pending
IN / Indiana Michigan Pwr	Not fixed	Per industrial tariff	Not disclosed	Defined in tariff	Approved Feb 2025

■ Tri-State G&T; \$2.7M/MW collateral is the highest nationally. Study deposits: \$80K–\$250K (non-refundable). Full tracker: sepapower.org/large-load-tariffs-database

Colorado — Xcel Energy Large-Load Tariff (Deep Dive)

Xcel filed a long-awaited large-load tariff proposal for Colorado data centers this month. The proposal is notably less restrictive than the Colorado PUC's November 2025 guiding principles, which proposed a \$250,000 non-refundable study deposit and an exit fee equal to 75% of projected total usage. Xcel's proposal sets the study deposit at \$120,000, structures the exit fee as the sum of remaining minimum monthly bills, and sets collateral at six months of estimated operations costs. The PUC approved 6,000 MW of new generation for Xcel — down from 14,000 MW requested — creating capacity headroom concerns for developers banking on larger interconnections.

Our Read: Xcel's exit fee formula (remaining minimum monthly bills) is materially better than 75% of total projected usage. Engage early in the proceeding if you have Colorado projects; the PUC will likely push toward the more punitive structure during review.

Sources: zi.org · coloradosun.com · Colorado PUC

Canadian Provincial Frameworks — New for Issue #1

Canada's four largest provinces have all moved from "first-come, first-served" connection policies to selective, policy-aligned frameworks for large loads. Sources: osler.com · mccarthy.ca · td.com

Province / Regulator	Mechanism	Effective / Status	Intensity
Québec Régie de l'énergie / Hydro-Québec	Ministerial authorization required for any load ≥5 MW (Bill 69, Jun 2025). Hydro-Québec proposed new DC-specific tariff at 13¢/kWh — roughly double the current high-power rate — applies to facilities >5 MW; 5-year transition for existing DCs.	Régie ruling pending; tariff in force H2 2026	STRICTEST
Alberta AESO	Two-phased connection strategy (Jun 2025). Interim 1,200 MW cap on large loads (≥75 MW) through 2028 for projects not requiring new transmission upgrades. AI Data Centres Strategy targets \$100B private investment over 5 years. 10+ GW in queue vs 1.2 GW cap.	Phase 1 in force June 2025; Phase 2 framework expected late 2026	CAPPED
Ontario Ministry of Energy / IESO	Bill 40 (Royal Assent Dec 11, 2025) — amendments to Electricity Act enable Minister of Energy and Mines to evaluate DC interconnection applications based on economic impact, job creation, energy intensity. DCs forecast at 13% of new Ontario demand by 2035.	Royal Assent Dec 11, 2025; regulations forthcoming	SELECTIVE
British Columbia BC Hydro / Bill 31	Competitive allocation process launched January 2026 under Bill 31 (Energy Statutes Amendment Act). 400 MW total cap for AI/DC projects over first two years. Natural-resources sectors (mining, LNG, forestry) prioritized over DCs.	Live January 2026	SELECTIVE

Québec — Hydro-Québec's 13¢/kWh DC Tariff (Deep Dive)

■ HIGH IMPACT · CANADA

In February 2026, Hydro-Québec submitted a tariff proposal to the Régie de l'énergie setting a new electricity rate of 13 CAD cents per kWh for data centres exceeding 5 MW — roughly double the current high-power rate paid by other large industrial customers. The new rate would apply to both new and existing facilities, with existing facilities transitioning over 5 years. The proposal follows the Québec government's January 2026 directive to the Régie to establish separate electricity customer categories for DCs and blockchain operations (blockchain set at 19.5¢/kWh, 3-year transition). Combined with Bill 69's ministerial authorization regime for any load ≥5 MW, Québec is now the most regulated DC market in Canada.

Developer/Operator Impact: If approved, the tariff materially changes project economics for Québec DCs. Re-underwrite all Québec projects on the assumption of 13¢/kWh delivered cost. Existing Québec facilities have a 5-year transition window; use it to evaluate relocation, on-site generation supplementation, or workload migration. The Ministerial authorization process (Bill 69) is now binding — budget 9–12 months for approval, and prepare to demonstrate technical feasibility, economic benefits, and environmental/social impact.

Sources: datacenterdynamics.com · osler.com · thelogic.co

SECTION 03

ISO/RTO Grid Desk — US & Canada

PJM — Co-Location & BTMG Tariff Compliance

■ HIGH IMPACT

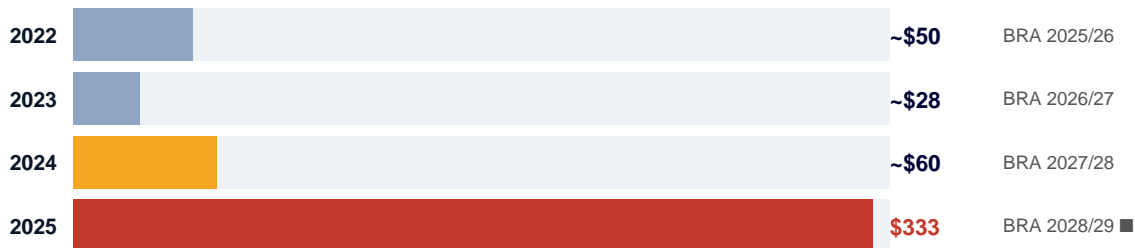
PJM's February 16 compliance filing introduces a 50 MW threshold for BTM facilities: new loads exceeding 50 MW are ineligible for "netting" — offsetting grid withdrawals with on-site generation to reduce transmission costs. Existing BTMG participants are grandfathered; the transition period ends December 18, 2028. Capacity auction prices rose from ~\$60/MW-day (2024) to over \$300/MW-day (2025). The December 2025 auction closed 6,600 MW short of its reserve margin, underscoring resource adequacy pressure in PJM.

Developer/Operator Impact: The 50 MW netting threshold is a major cost driver for mid-size BTM projects in PJM. Re-run project economics without netting benefits. Review existing BTMG agreements for grandfather eligibility before December 2028. Revise O&M; budgets — the capacity price spike materially affects operating cost models.

Sources: datacenterdynamics.com · agreements.pjm.com/oatt/3898

PJM CAPACITY MARKET PRICE SPIKE 2022–2025

Base Residual Auction clearing prices (\$/MW-day) · Rising prices reflect resource adequacy stress driven by data center load growth



Scale: 0 to \$340/MW-day · 2025 BRA closed 6,623 MW short of PJM reserve margin · Source: agreements.pjm.com/oatt/3898 · bakerbotts.com

■ **BTM Economics Inflection:** At \$333/MW-day, BTM generation avoiding PJM capacity charges is dramatically more attractive — even before accounting for the 50 MW netting threshold that further increases on-site generation value. The price spike is also a direct driver of the interruptibility and demand-response requirements explored in Section 05 below.

ERCOT — No Material Developments This Week

No material large-load interconnection protocol changes issued. The Stargate/OpenAI flagship Texas project remains in reported limbo following partner disputes. Next CDR (Capacity, Demand and Reserves) report due Q2 2026 (ercot.com/gridinfo/resource).

CAISO — Cost Allocation Watch

CAISO cluster study results are pending. Cost allocation for large-load interconnections in California is governed primarily by local utility tariffs approved by the California Public Utilities Commission (CPUC), not a single CAISO-wide mechanism — adding state-regulatory uncertainty for projects in CAISO territory. Check the CAISO queue portal (caiso.com/planning) for individual project updates. No new cluster study outcomes this week.

AESO (Alberta) — Two-Phased Connection Strategy

■ HIGH IMPACT · CANADA

AESO published its two-phased large-load connection strategy in June 2025, introducing an interim 1,200 MW cap on data centre and other large-load projects (≥ 75 MW) through 2028 — limited to projects that do not require new transmission system upgrades. As of March 2026, AESO's queue contains over 10 GW of proposed DC projects against the 1,200 MW interim limit. AESO Phase 2 is expected to establish a longer-term framework addressing reliability standards, tariff redesign, cost allocation reviews, and updated forecasting; framework anticipated late 2026.

Developer/Operator Impact: The 1,200 MW cap is heavily oversubscribed; project selection by AESO will be the gating event. Two projects already allocated power under Phase 1: Greenlight Electricity Center (Pembina Pipeline + Kineticor) and Keephills DC (TransAlta). For projects not yet selected, the off-grid / behind-the-meter pathway (BYOP — Bring Your Own Power) is the alternative, particularly via natural gas — see Wonder Valley in Section 06.

Sources: osler.com · mccarthy.ca

IESO (Ontario) & BC Hydro — Selective Frameworks

■ WATCH · CANADA

IESO data shows DCs forecast at 13% of new Ontario electricity demand by 2035. With Bill 40 (Royal Assent Dec 11, 2025) now in force, IESO and transmitters/distributors must apply a screening framework prioritizing projects that deliver economic, strategic, and community benefits. Forthcoming regulations will operationalize the screening criteria. Separately, BC Hydro launched its competitive allocation process in January 2026 under Bill 31 (Energy Statutes Amendment Act): 400 MW allocated to AI/DC over 2 years; mining, LNG, forestry prioritized.

Developer/Operator Impact: Ontario and BC are now competitive allocation markets, not first-come/first-served. Position projects to demonstrate economic benefit (jobs, investment, tax base) and energy intensity efficiency. In BC, deprioritization vs natural-resources sectors means most DC capacity is effectively closed in the near term.

Sources: osler.com · td.com

SECTION 04

Tariff Terms Tracker — Market Standard Reference

Convergence baseline as of Q2 2026, based on 77 tariffs pending or in place across 36 states. Sources: sepapower.org/large-load-tariffs-database · latitudemedia.com · scottmadden.com

Term	Market Standard	Range Observed
Contract length	15 years	12–20 years
Min. demand charge (T&D)	85% of contracted capacity	80–90%
Min. demand charge (generation)	60–80% of contracted capacity	60–85%
Collateral / security deposit	\$1.5M–\$2.7M per MW	6 mo. bills to \$2.7M/MW
Study deposit (non-refundable)	~\$120,000–\$150,000	\$80K–\$250K
Exit fee	Remaining min. monthly bills	Up to 75% of total projected usage
Ramp schedule	3–4 years to full capacity	1–5 years
Applicable load threshold	≥ 50 MW (single site)	≥ 25 – ≥ 70 MW

Collateral red-flagged: Tri-State G&T; \$2.7M/MW is the highest observed nationally.

SECTION 05

Grid Connection Regulation & Interruptibility Requirements

The regulatory focus has shifted from technical interconnection standards to commercial and operational obligations: who pays for grid upgrades, and whether data centers can be curtailed or disconnected during emergencies. Texas SB 6 is the most advanced state model, but the framework is spreading nationally.

Texas SB 6 (Signed June 20, 2025) — The National Bellwether

■ HIGH IMPACT · ERCOT TERRITORY

Texas Senate Bill 6, signed by Governor Abbott on June 20, 2025, imposes the most comprehensive state-level regulatory framework yet for data center grid connections. Effective immediately, it applies to loads of 75 MW or more in ERCOT (threshold adjustable downward by PUCT). The bill directly addresses post-Winter Storm Uri reliability concerns and the rapid influx of data center load. Industry has termed one of its provisions the "Kill Switch Bill" — requiring remote-disconnect hardware on all new large loads from December 31, 2025. Key provisions are set out in the table below.

Sources: [bakerbotts.com](https://www.bakerbotts.com) · [bracewell.com](https://www.bracewell.com) · [mcquirewoods.com](https://www.mcquirewoods.com) · [jw.com](https://www.jw.com) · [pillsburylaw.com](https://www.pillsburylaw.com) · [perkinscoie.com](https://www.perkinscoie.com)

SB 6 Key Provisions for Large Loads (≥75 MW) in ERCOT

SB 6 Provision	What It Requires	When / Docket
Mandatory load curtailment & remote disconnect	Utilities must install curtailment hardware on all new large loads before energisation. ERCOT may direct loads with on-site backup generation ≥50% of demand (non-grid-export) to deploy that generation or curtail load during emergencies, after all other market services are exhausted. Critical industrial customers and critical natural gas facilities are exempt.	New interconnections from Dec 31, 2025 PURA § 37.0561 / § 39.170
On-site backup generation disclosure	All large loads must disclose to the utility and ERCOT the presence, capacity, and capabilities of on-site backup generation as part of their interconnection request. Disclosure alone does not trigger ERCOT dispatch authority unless all § 37.0561 conditions are satisfied.	Effective Sept 1, 2025
Co-location net metering approval	New BTM net-metering arrangements between existing grid-facing generators (as of Sept 1, 2025) and new large loads (≥75 MW) require ERCOT study (120 days) + PUCT approval. PUCT may impose callable dispatchable capacity and BTM curtailment conditions.	Applies from Sept 1, 2025 PURA § 39.169
Interconnection cost sharing & study fees	Large loads must contribute to grid upgrade costs. Flat study fee of at least \$100,000 for initial transmission screening; additional fees for expanded capacity. PUCT directed to establish uniform contribution standards minimising stranded infrastructure costs.	PUCT rulemaking ongoing Project 58317
Voluntary demand reduction service	ERCOT directed to competitively procure demand reductions from large loads (≥75 MW). Participants receive ≥24 hours notice before events; must remain curtailed for duration of emergency. Requires real-time load telemetry and fast-response demand controllers.	PUCT Project 58482 Adoption expected 2026
4CP cost allocation review	PUCT must evaluate whether the Four Coincident Peak (4CP) methodology for wholesale transmission cost allocation ensures large loads pay their fair share. Related rulemaking by Dec 31, 2026.	PUCT Project 58484 Rulemaking by Dec 2026

Developer/Operator Impact (Texas / ERCOT): Any data center interconnecting after December 31, 2025 in ERCOT must install remote-disconnect hardware before energisation and contractually accommodate curtailment. Design for graceful degradation — not full shutdown — during curtailment events. Battery storage behind the meter can satisfy curtailment obligations while maintaining critical IT load. The co-location net-metering approval process (ERCOT study + PUCT approval) adds 6–9 months to project timelines for any BTM arrangement pairing an existing generator with a new load.

SB 6 as Bellwether — Interruptibility & Cost-Sharing Spreading Nationally

■ WATCH · MULTI-STATE

Texas SB 6 is the first comprehensive state model for large-load grid regulation, and other states are already following. More than 300 data center bills were introduced in 30+ states in the first six weeks of 2026 alone (MultiState, March 2026 — multistate.us), with a decisive shift from incentive-based policies toward regulatory oversight and cost recovery. Key parallel developments are shown in the table below.

Sources: datacenterfrontier.com · afslaw.com · multistate.us · utilitydive.com · marylandmatters.org

State / Forum	Mechanism	Status
PJM states — interruptible service proposal	State legislators (50+, led by MD Sen. Fry Hester) proposed requiring PJM to provide only interruptible service to new data centers until they self-procure capacity. NRDC model: data centers receive power 99.97% of hours without a firm capacity guarantee, saving ratepayers tens of billions of dollars.	Proposal active; FERC / PJM proceeding ongoing
Oregon POWER Act (Aug 2025)	Directs Oregon PUC to create a separate rate class for large energy use facilities (≥20 MW), ensuring grid infrastructure costs driven by data centers are allocated to developers, not ratepayers.	Signed Aug 2025 Rulemaking ongoing
Arizona HB 2756 (2026)	Would require AZ PUC to adopt rules ensuring new data center grid connection costs are not shifted onto other retail customers.	In committee 2026 afslaw.com
Maryland SB 596 / HB 940 (2026)	Encourages data centers to participate in demand response programs, shifting or reducing peak usage to protect residential ratepayers from cost increases driven by large-load growth.	Active 2026 session marylandmatters.org
18+ states (2026)	Bills creating special rate classes for large energy users, requiring data centers to fund infrastructure improvements and demonstrate benefits to ratepayers before connection.	Active 2026 sessions multistate.us

Developer/Operator Impact: Interruptibility and cost-sharing requirements are moving from Texas-specific to industry-wide. Underwrite all new projects on the assumption that (1) interruptibility hardware will be required, (2) the data center will bear 100% of grid upgrade costs, and (3) some form of demand response participation will be expected or incentivised. Projects with genuine demand flexibility — battery storage, workload scheduling, or modular shutdown capability — will have a competitive advantage in regulatory proceedings and utility negotiations.

Grid Connection Power Quality — Regulatory Obligations for Data Centers

Power quality obligations are set by the utility interconnection agreement and applicable state tariff, not by a single federal standard. The parameters below are the binding project-level requirements; generic IEEE or NERC standards define the floor but utilities frequently impose stricter terms in large-load tariffs.

Key Practice Point: Do not rely on generic IEEE or NERC standards for project-level compliance. The binding obligations are in the utility General Terms & Conditions and your specific interconnection agreement. In ERCOT, SB 6-derived curtailment protocols add an operational layer on top of standard power quality rules. Engage power quality engineering at interconnection study stage, not at commissioning.

Sources: nerc.com/pa/Stand · standards.ieee.org/ieee/519 · ferc.gov

Parameter	Regulatory Basis	Typical Requirement
Power factor	Utility tariff / interconnection agreement	0.95 lagging minimum at POI; penalty tariffs for non-compliance common in large-load tariffs
Harmonic distortion	IEEE 519-2022 (voltage THD); utility interconnection spec (current TDD)	Voltage THD: voltage-level dependent. Current TDD: based on short-circuit ratio & max demand load current at PCC. Confirm project-specific limits with utility.
Voltage ride-through	NERC PRC-024 / utility spec	Varies by voltage level. Confirm for co-located generation and load-side equipment.
Reactive power	Utility interconnection agreement; FERC Order 827 where non-synchronous generation is co-located	Obligations project-specific. Active compensation may be required. Confirm in interconnection agreement before finalising electrical design.
Load ramp rate	Utility tariff (emerging); ERCOT protocol for SB 6 loads	Maximum MW/minute ramp rate increasingly specified in large-load tariffs and SB 6-derived protocols. Design UPS and BESS dispatch accordingly.

SECTION 06

On-Site & Behind-the-Meter Power Strategies

Covering BTM technology options, commercial structures, regulatory treatment, and deal activity for data center developers pursuing grid-independent or hybrid power.

BY THE NUMBERS — BTM MARKET CONTEXT Q2 2026

- **25%+** of new DC capacity now BTM-sourced (Landgate BTM Report 2026: landgate.com) · **56%** of developers exploring co-located/on-site generation (Foley 2026: datacenterhawk.com) · **25–33%** of incremental DC demand through 2030 projected BTM (McKinsey/Jefferies: latitudemedia.com)
- Grid connections now taking **3–5 years** in constrained markets (datacenterdynamics.com) · Gas turbine lead times reached **243 weeks** in Q2 2025 (Wood Mackenzie: datacenterknowledge.com) · Time-to-power running **1.5–2 years longer** than expected (Bloom Energy Survey Mar 2026)

BTM Technology Options — Comparative Overview

Technology	Deploy	Scale	Key Advantage	Key Risk
Gas turbines / recip. engines	Recip: 18–24 mo.; large-frame: longer	10 MW–multi-GW	Fastest deployment; proven baseload reliability	Recip/modular: 18-24 mo.; large-frame turbines: 200+ weeks lead time (2025)
Solid-oxide fuel cells	12–18 mo.	1–100+ MW modular	Lower emissions; modular; 24/7 CFE alignment	Still fossil gas fuel; higher £/MW capex
Solar + BESS	18–36 mo.	10–500+ MW	ESG-aligned; IRA ITC/PTC available	Intermittency; insufficient standalone baseload
Gas + CCUS	3+ years	200 MW+	Large-scale clean baseload; hyperscaler 24/7 CFE	Cost; permitting complexity; single-asset risk
SMRs	2030+	50–300+ MW	Zero-carbon 24/7; avoids grid entirely	NRC licensing; first-of-kind cost uncertainty

PJM's 50 MW BTM Netting Threshold — What It Means in Practice

■ HIGH IMPACT FOR BTM PROJECTS IN PJM TERRITORY

Under PJM's February 2026 compliance filing to FERC, new BTM arrangements for loads exceeding 50 MW can no longer "net" their grid withdrawals against on-site generation — eliminating the primary cost benefit that made BTM economically attractive for large data centers in PJM territory. The netting mechanism allowed operators to reduce transmission, ancillary service, and capacity charges by the amount of self-generated power. Its removal adds meaningful cost to BTM economics and has drawn strong opposition from the PJM Industrial Customer Coalition and Industrial Energy Consumers of America, who argue the change makes hundreds of megawatts of existing CHP (Combined Heat and Power) capacity uneconomic. Outside PJM, netting rules vary; no equivalent threshold has been proposed by MISO, ERCOT, or CAISO to date.

Developer/Operator Impact: Any PJM project above 50 MW that assumed BTM netting benefits should be re-underwritten immediately. Netting removal may materially change economics depending on energy price, capacity cost, generation cost, and grandfathering eligibility. Quantify the cost delta before signing any power delivery agreement. Confirm grandfather eligibility before December 2028.

Sources: datacenterdynamics.com · marcellusdrilling.com

Commercial Structures for BTM Procurement

Structure	How It Works	Who Bears Capex
Power Delivery Agreement (PDA)	Energy provider installs & owns on-site generation; DC pays per-MWh rate over contract term	Provider — off-balance sheet for DC
Developer-Owned BTM	DC owns and operates generation asset directly; full control, full cost	Data center — on-balance sheet
Hybrid: BTM Bridge + Grid PPA	BTM generation covers load until grid interconnect completes; transitions to front-of-meter supply	Split / negotiated

PDA structure (typified by VoltaGrid — voltagrid.com) is growing fastest, keeping generation capex off the data center developer's balance sheet.

Notable Recent BTM Transactions

Project	Scale	Technology	Notes & Source
VoltaGrid / Oracle (TX)	2.3 GW	Natural gas, off-grid	w/ Energy Transfer; fully off-grid. latitudemedia.com
Joule / Utah DC Campus	1.3 GW	BTM, fully islanded	Islanded from Rocky Mountain Power. latitudemedia.com
FO Permian / Hivolt (TX)	5 GW	Off-grid gas, Permian	Largest announced BTM project to date. latitudemedia.com
Meta / Entergy (LA)	N/D	Gas + potential CCUS	\$10B data center; CCUS integration option. bcq.com
Bloom Energy / Brookfield	Up to 5 GW	Solid-oxide fuel cells	\$5B Brookfield commitment to Bloom BTM systems. latitudemedia.com

Developer/Operator BTM Watchpoints: (1) **Permitting:** Air permits for gas-fired BTM generation are increasingly contentious — budget 12–18 months in states with strict air quality rules (CA, CO, NY). (2) **Microgrid design:** Anti-islanding protection, black-start capability, and synchronisation requirements must be negotiated into the interconnection agreement even for nominally islanded BTM projects. (3) **IRA tax credits:** BTM solar + storage qualifies for ITC/PTC; natural gas BTM generally does not. Structure technology mix accordingly. (4) **Operational model:** On-site generation demands new skills. Consider a PDA structure to avoid adding power plant O&M to your competency requirements.

Canadian BTM — Alberta-Centric Due to Provincial Restrictions

With Québec restricting load ≥5 MW (Bill 69) and BC capping AI/DC at 400 MW, Canadian BTM activity has concentrated in Alberta where natural-gas BYOP is permitted. Sources: canada.constructconnect.com · thelogic.co · datacenternews.ca

Project	Location	Scale / Status	Key Notes
Wonder Valley Kevin O'Leary backed	Grande Prairie, AB	Up to 7.5 GW (BYOP gas)	\$70B announced · fully off-grid natural-gas generators · AB government exempted from environmental assessments · projected 25.7–30.5 Mt CO ₂ /yr without CCUS · ~10% of AB total gas supply
Synapse 1 GW proposed	Rural Olds, AB	1 GW (planned)	AUC rejected initial application March 2026 for incompleteness; company intends to refile. Mid-2026 originally targeted
BitDeer Fox Creek site	Fox Creek, AB	101 MW (gas)	Acquired site for natural-gas plant directly powering DC operations
Greenlight Electricity Center Pembina + Kineticor	Alberta	Allocated under AESO Phase 1	One of two projects selected by AESO under interim 1,200 MW limit; in development
Keephills DC TransAlta	Alberta	Allocated under AESO Phase 1	Second AESO-selected project; co-located with TransAlta thermal generation

Canadian BTM Watchpoints: (1) **Alberta gas-only structurally:** Wonder Valley's scale (7.5 GW gas, ~10% of AB gas supply) is testing political and environmental tolerance — expect future projects to face stricter assessment requirements. (2) **Carbon exposure:** 25.7–30.5 Mt CO₂/yr from Wonder Valley alone exceeds entire industries' emissions; CCUS retrofit may become regulatory requirement. (3) **Quebec/BC closed:** BTM as alternative to grid is effectively unavailable in Québec (Bill 69) and BC (Bill 31). Hyperscalers seeking Canadian capacity outside Alberta must accept provincial allocation processes.

SECTION 07

Deals, Projects & Market Signals

Google / Xcel Energy MN — 1,900 MW Clean Energy Deal

Google has committed to fully fund 1,900 MW of wind, solar, and battery storage in Minnesota, along with all associated grid infrastructure upgrade costs — a "hold harmless" structure protecting existing ratepayers entirely. This sets a hyperscaler precedent that regulators in other states may attempt to codify into tariff requirements for all large-load customers.

Market Signal: This model is becoming a regulatory expectation, not just a voluntary commitment. Developers without hyperscaler balance sheets should model the full grid infrastructure cost as a potential developer obligation when evaluating new markets.

Source: route-fifty.com

Market Signal: New Data Center Deals Down 40%+ Q3→Q4 2025

New data center deals fell more than 40% between Q3 and Q4 2025, with only approximately one-third of the announced 240 GW of new construction actively being built. The Stargate project in Texas has reportedly stalled. Hyperscaler capex may fall by half in 2026 relative to headline announcements.

Developer/Operator Impact: For independent data center developers, this demand softening is a potential colocation market opportunity. However, it also validates utilities' concern about stranded infrastructure costs, sustaining regulatory pressure for strict large-load tariff terms regardless of project volumes.

Source: itif.org

Bell Canada Announces Largest Canadian AI Data Center — Saskatchewan

Bell Canada announced in March 2026 plans to build Canada's largest AI data centre outside Regina, Saskatchewan. Specific capacity figures not yet disclosed, but the project would exceed all current Canadian DCs in capacity. Saskatchewan offers grid headroom and natural-gas access; the province has not yet introduced a DC-specific regulatory framework, making it an attractive alternative to Québec/Alberta/Ontario/BC.

Market Signal: Watch for Saskatchewan, Manitoba, and Atlantic provinces to emerge as "second-tier" Canadian DC locations as the major four provinces saturate or restrict. Bell's move indicates incumbent Canadian operators are exploring alternative provinces. Saskatchewan's lack of a DC-specific tariff regime is a near-term opportunity but likely temporary as scale grows.

Source: datacenternews.ca

Canada Total Market Context: 309 DCs, ~\$70B+ Pipeline (TD Mar 2026)

TD Economics' March 2026 report identified 309 operational DCs across Canada (Ontario 105, Québec 57, BC 35, Alberta 22), with current capacity ~750 MW projected to reach ~1.16 GW by 2029. Eight hyperscale projects under construction; ~36 in planning. Hydro-Québec's forecast: data centres reaching 1+ GW peak in Québec by 2035. Canada total electricity from DCs could increase 400%+ by 2050 per Climate Institute analysis.

Market Signal: Canada is a small market relative to the US (~10% the size by capacity) but growing rapidly. Sustained scarcity of grid headroom across major provinces creates structural pricing power for established Canadian DC operators.

Sources: td.com · thelogic.co · climateinstitute.ca

SECTION 08

Regulatory Calendar — Next 60 Days

Date	Body	Action	Reference
Apr 16, 2026	FERC	Partial accept/reject of PJM co-location compliance (EL25-49); rejected revised Co-Located Load definition; further compliance due May 18	EL25-49 · natlawreview.com
By Jun 30, 2026	FERC	ANOPR action on large-load interconnection standards (RM26-4-000); FERC committed Apr 16 to act quickly and in a legally durable way	RM26-4-000 · ferc.gov
May 18, 2026	PJM	Further compliance filing due — must revise Co-Located Load definition per FERC April 16 rejection	EL25-49 · troutmanenergyreport.com
TBD Q2 2026	FERC	Paper hearing rate order for PJM Firm/Non-Firm Contract Demand services; BTM netting threshold finalisation	ferc.gov
Q2 2026	Colorado PUC	Review and approval of Xcel Energy large-load tariff proposal	CO PUC · coloradosun.com
Q2 2026	ERCOT	CDR (Capacity, Demand & Reserves) report release — large load demand update	ercot.com/gridinfo/resource
Dec 18, 2028	PJM	BTM transition period ends — all BTMG arrangements must comply with new 50 MW threshold	blankrome.com
Ongoing	Multi-State	Xcel large-load tariff filings in 4 additional states	utilitydive.com (Feb 6, 2026)
H2 2026	Québec / Régie	Régie de l'énergie ruling on Hydro-Québec's 13¢/kWh DC tariff filing	datacenterdynamics.com
Late 2026	Alberta / AESO	Phase 2 framework expected: reliability standards, tariff redesign, cost allocation reviews	mccarthy.ca
Forthcoming	Ontario / Min. Energy	Bill 40 implementing regulations expected; screening framework for DC interconnection applications	osler.com

SECTION 09

The Bottom Line — 3 Takeaways for Leadership

1

Risk: Collateral is a core bankability and capital-structure issue — budget it now.

With collateral requirements ranging from \$1.5M to \$2.7M per MW across emerging tariffs, a 100 MW project requires \$150M–\$270M in credit support before the first server rack is installed. For independent developers without investment-grade credit ratings, this is a capital structure problem, not a tariff negotiation problem. Model this as a use of capital competing with equity deployment — it materially changes project IRR. Credit quality, parent guarantees, and letters of credit can vary — but collateral is now a core bankability question, not a minor tariff item.

2

Opportunity: BTM is now a first-principles power strategy, not a workaround.

With 25–33% of incremental data center demand through 2030 expected to be met by BTM solutions, and gas turbine lead times stretching to 243 weeks, developers who structured their BTM procurement pipelines in 2024–2025 have a significant time-to-power advantage. The window to lock in gas turbine delivery slots at reasonable lead times is closing. If you do not have a BTM power strategy today, your 2027–2028 project pipeline is at risk.

3

Action Required: Audit every active LOI and PSA for exit fee and BTM netting exposure.

Two converging risks require immediate portfolio review: (1) Exit fee structures are being tightened in every active tariff proceeding — confirm whether your agreements will be superseded by the incoming approved tariff in each state. (2) If any project model in PJM territory assumed BTM netting benefits for loads above 50 MW, those economics are now broken. Re-underwrite before the next capital commitment.



Key Reference Links · ferc.gov · sepapower.org/large-load-tariffs-database · agreements.pjm.com/oatt/3898 · caiso.com/planning · ercot.com/gridinfo/resource · nerc.com/pa/Stand · poweraether.com