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September 25, 2026

VIA ELECTRONIC FILING

puc.FilingCenter@puc.oregon.gov

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

Re: R 676 – Multi-Year Framework (HB 3179 & SB 688)

Attention Filing Center:

Idaho Power Company ("Idaho Power" or "Company") respectfully submits its pre-read related to Idaho Power Company's Transmission and Other Costs information in response to the Oregon Public Utility Commission Staff's ("Staff") Phase 2 Workplan.

Idaho Power appreciates the opportunity to provide this pre-read and participate in this process.

The Company looks forward to continued engagement with Staff and stakeholders as this work progresses. If you have any questions regarding this filing, please contact Regulatory Consultant Kelley Noe at knoe@idahopower.com.

Sincerely,

Connie Aschenbrenner

CA:sg

Attachment

1221 W. Idaho St (83702)
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Boise, ID 83707

Idaho Power Pre-Read: Transmission and Other Capital

Purpose

This pre-read provides background on Idaho Power's transmission, generation, storage, and other non-distribution capital; explains how those investments are currently planned, forecast, and reflected in rates; and identifies key considerations for applying the Supplemental Capital Funding Mechanism ("SCFM") to capital requirements. Many of the same implementation principles discussed for distribution capital apply here: going-in rates should use Idaho Power's existing test-year methodology, the indexed revenue cap should preserve cost-management discipline during the Multi-Year Rate Plan ("MRP") term, and the SCFM should provide a practical path for material investment needs that cannot reasonably be accommodated within the indexed revenue path.

Overview of Transmission and Other Costs

Transmission and other costs include investments outside the distribution system, such as transmission lines, substations serving the transmission function, generation resources, storage, information technology systems and general plant needed to serve customers. These investments support system reliability, resource adequacy, renewable integration, load growth, compliance obligations, operational modernization, and the Company's ability to continue providing safe and reliable service.

Unlike more routine or recurring capital programs, many capital investments are driven by discrete system needs, resource planning outcomes, major asset condition issues, technology requirements, transmission interconnection obligations, or regulatory and reliability standards. These drivers do not necessarily track general inflation and may change materially as system conditions, customer needs, market conditions, resource availability, and compliance obligations evolve.

Planning and Investment Drivers

For resource-related capital, Idaho Power relies on its Integrated Resource Plan ("IRP") to evaluate system needs, identify preferred resource portfolios, and to inform the need for future resource acquisitions. The timing, cost, and specific project configuration is determined with Commission oversight through a competitive procurement process, where current market conditions, interconnection timelines, permitting, supply chain constraints, and customer load forecasts inform specific resource selection.

Transmission capital can be driven by a multitude of factors, including reliability requirements, system planning studies, generator interconnection needs, load growth, regional coordination, replacement of aging infrastructure, and the need to move energy from resources to load. These investments often involve long lead times, external dependencies, and changing cost estimates, which makes project-level flexibility important during a multi-year rate plan.

General plant capital is driven by many factors including compliance with security requirements (both physical and cyber security), technological obsolescence, and aging facilities.

Forecasting Capital and Establishing Going-In Rates

Idaho Power recommends using its existing test-year methodology to establish capital reflected in going-in rates. Larger, known and measurable projects can be identified and forecast

individually. For capital projects below the applicable individual project threshold, the forecast should rely on a historical methodology that reflects recurring capital activity rather than attempting to identify each smaller project separately. This recognizes that smaller capital work is necessary to support ongoing utility operations but is typically better forecast through reviewing historical data and trends, project-type groupings, and allocation methods than through a fixed project-by-project list.

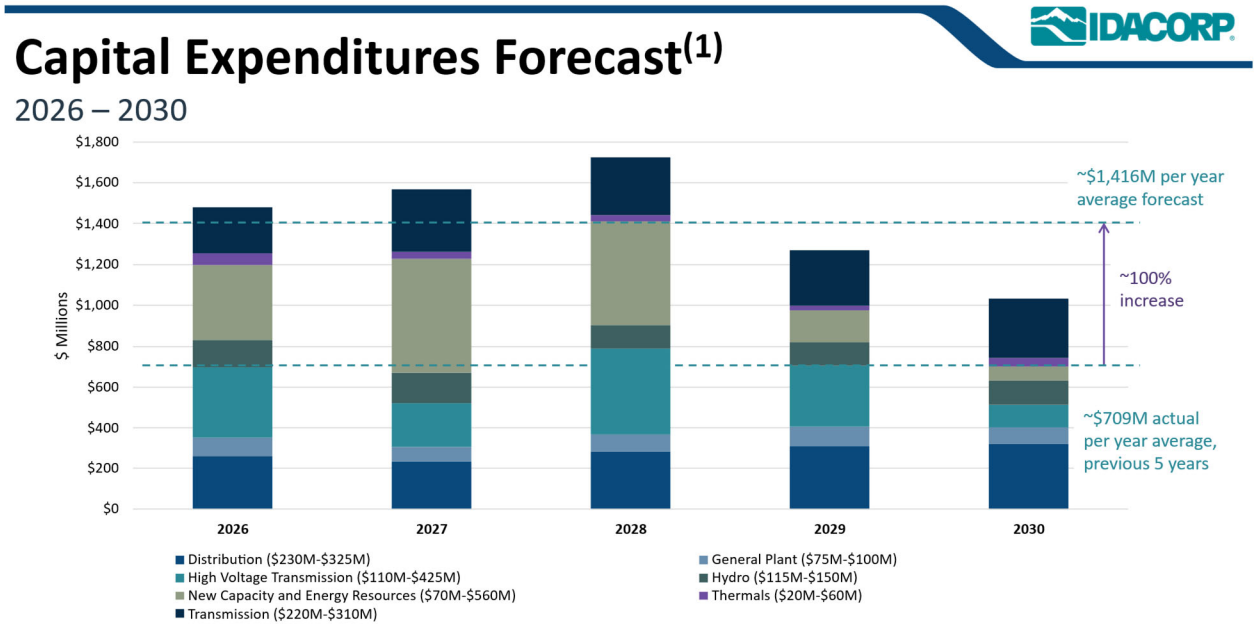
This approach provides a reasonable starting point for going-in rates without requiring the MRP to lock in a fixed project list for the full five-year term. Forecasts used for going-in rates should establish the capital and associated revenue requirement that is subject to the index and the supplemental capital funding mechanism.

Transmission and Other Capital Within the Indexed MRP

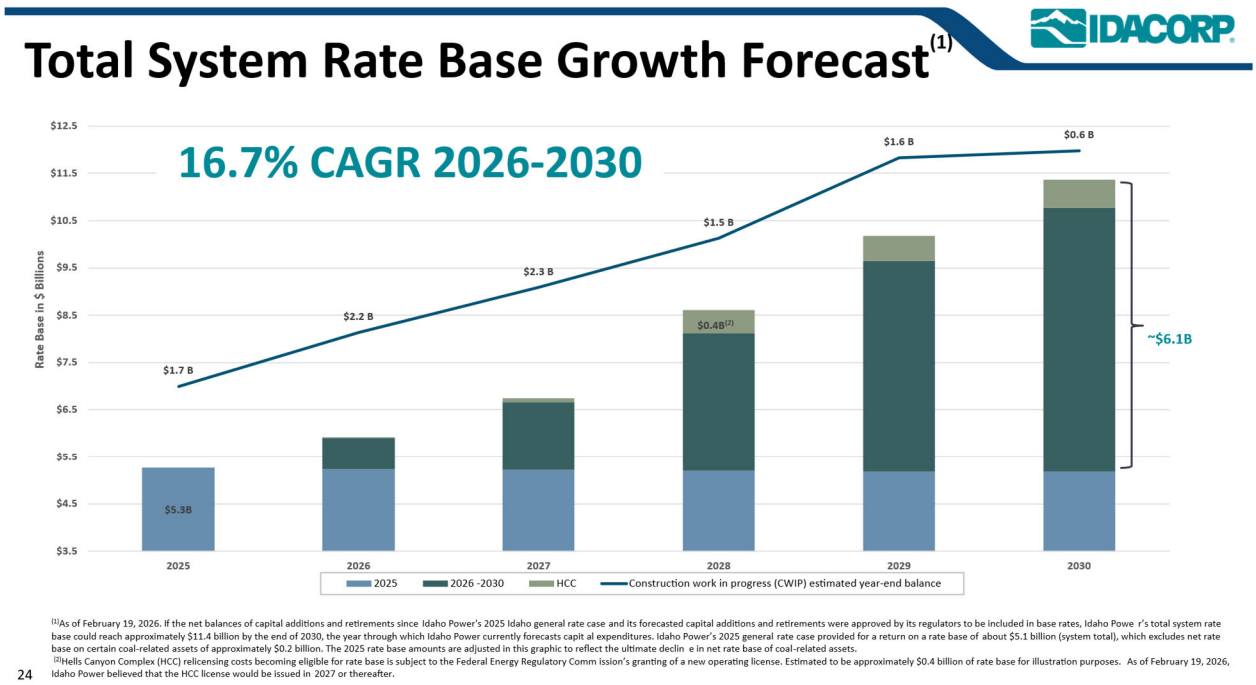
Under the Phase 1 framework, most costs are included within the MRP's indexed revenue cap, with limited exclusions. For capital, the going-in rate forecast establishes the level to be reflected in base rates, but routine forecast-to-actual differences should not automatically result in annual capital adjustments during the MRP term. The SCFM should instead be available for material capital requirements that were not reflected in going-in rates and cannot reasonably be accommodated within the indexed revenue path.

As described above, Idaho Power's capital spending is driven by factors such as resource adequacy, transmission reliability, interconnection obligations, compliance requirements, technology replacement, permitting and procurement constraints, and other project-specific circumstances. As a result, capital investment levels may differ significantly from general inflation trends. If the indexed revenue path does not reasonably reflect these material capital needs, the SCFM must be available as a defined mechanism to evaluate and address them.

The figures below show Idaho Power's forecasted capital spend and rate base growth on a system basis. These trends reflect capital investment patterns that are not aligned with a general inflation-based adjustment.



(1)As of February 19, 2026, this graphic is a representation of the 5-year capital expenditures forecast. See IDACORP's 2025 Form 10-K for a summary of project types included in the 5-year forecast.



(1)As of February 19, 2026. If the net balances of capital additions and retirements since Idaho Power's 2025 Idaho general rate case and its forecasted capital additions and retirements were approved by its regulators to be included in base rates, Idaho Powe r's total system rate base could reach approximately $11.4 billion by the end of 2030, the year through which Idaho Power currently forecasts capit al expenditures. Idaho Power's 2025 general rate case provided for a return on a rate base of about $5.1 billion (system total), which excludes net rate base on certain coal-related assets of approximately $0.2 billion. The 2025 rate base amounts are adjusted in this graphic to reflect the ultimate declin e in net rate base of coal-related assets.
(2)Hells Canyon Complex (HCC) relicensing costs becoming eligible for rate base is subject to the Federal Energy Regulatory Comm ission's granting of a new operating license. Estimated to be approximately $0.4 billion of rate base for illustration purposes. As of February 19, 2026, Idaho Power believed that the HCC license would be issued in 2027 or thereafter.

Supplemental Capital Funding Mechanism Considerations

The relevant consideration within an SCFM should be whether material capital investment requirements have emerged that were not reflected in going-in rates and cannot reasonably be accommodated within the indexed revenue path while the utility continues to meet identified system and customer needs. Regulatory lag, financing requirements, and other financial effects may inform that determination, but the mechanism should be grounded first in the investment need and the utility's service obligations.

A workable SCFM should provide sufficient flexibility to address material capital investment needs while preserving appropriate review, customer protections, and the incentives inherent in an index-based MRP. The mechanism should allow investments to be addressed before they create significant regulatory lag or require more disruptive remedies such as reopeners or off-ramps.

Other Implementation Considerations

Depreciation. Plant included in going-in rates should use the Commission-approved depreciation rates in effect for the applicable plant accounts. If depreciation rates change during the MRP term, the revenue requirement effect should be addressed through an authorized adjustment, deferral, or coordinated timing with rebasing.

Performance metrics. For transmission and resource-related capital, relevant outcomes may include reliability, resource adequacy, operational performance, and progress toward identified planning needs.

Rebasing. At the conclusion of the MRP term, rebasing would establish new going-in rates for the subsequent MRP period using actual recorded rate base and other revenue requirement components, including investments recovered through any SCFM. Actual recorded plant balances

would provide the foundation for applying Idaho Power's test-year forecasting methodology to establish capital reflected in the next set of going-in rates.

Idaho Power Recommendations

- Establish going-in rates using Idaho Power's existing test-year methodology, including individualized treatment for large, known and measurable capital projects and historical/allocation methods for smaller or recurring capital activity.
- Recognize the IRP as an important planning foundation for resource-related capital decisions while preserving flexibility for changes in procurement, timing, cost, and project configuration.
- Design the SCFM to address material transmission, generation, storage, IT, and other capital needs that were not reasonably reflected in going-in rates and cannot reasonably be accommodated within the indexed revenue path.
- Use performance metrics focused on customer and system outcomes.
- Conduct comprehensive rebasing at the next MRP filing, with actual recorded plant balances providing the foundation for establishing new going-in rates.

This framework preserves the discipline and predictability of the indexed MRP while providing a practical and reviewable path for material non-distribution capital investments that are necessary to meet system, customer, and regulatory obligations.