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IDAHO PUBLIC
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND AUTHORITY TO IMPLEMENT CERTAIN MEASURES TO MITIGATE THE IMPACT OF REGULATORY LAG.	)	CASE NO. IPC-E-25-16

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MITCH COLBURN

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Mitch Colburn. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Vice President of Planning, Engineering and Construction.

Q. Please describe your educational background.

A. I graduated from the University of Idaho in 2006 with a Bachelor of Science degree in Electrical Engineering, Summa Cum Laude. Thereafter, I obtained a Master of Engineering degree in Electrical Engineering from the University of Idaho in 2010 and a Master of Business Administration from Boise State University in 2015. I am a licensed Professional Engineer in the State of Idaho.

Q. Please describe your work experience with Idaho Power.

A. I have worked at Idaho Power since 2007. Prior to my current role, I served as Director of Engineering and Construction, Director of Resource Planning and Operations, Senior Manager of Transmission & Distribution Strategic Projects, Engineering Leader over 500-kilovolt ("kV") and Joint Projects. I held several engineering roles prior to these leadership roles.

I am responsible for an organization of more than

275 employees focused on multiple areas: (1) identifying future electric grid infrastructure requirements, (2) resource procurement efforts, (3) operating and maintaining the electric grid, including the wildfire mitigation program and vegetation management, and (4) designing, engineering, and constructing grid infrastructure projects.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to discuss the investments the Company has made in the electrical grid to ensure the provision of safe, reliable service to customers. I will detail specific investments anticipated to be completed in 2025 and included in the Company's request in this case, demonstrating Idaho Power's prudent investment in the electrical grid at the transmission and distribution levels.

Q. How is your testimony organized?

A. My testimony will begin with a discussion of the transmission and distribution-related major projects, or those projects over $2 million ("major projects"), included in Idaho Power's request in this case that are necessary for the Company's continued delivery of safe, reliable electric service. Next, I will discuss the Wood River Valley Reliability Project ("WRV Project"), a combined distribution and transmission project for which

the Company has received a Certificate of Public Convenience and Necessity ("CPCN"), the distribution portion of those investments which are proposed for recovery in this case. I will also discuss a project necessary for continued support of Idaho Power's mobile workforce system. Finally, my testimony will review the Company's planned enhanced 2025 wildfire mitigation efforts that support the associated capital and operation and maintenance expenditures proposed for recovery in this case.

I. TRANSMISSION INVESTMENTS

Q. Please describe how the Company defines the transmission-related portion of the electrical grid.

A. Transmission generally describes the bulk or high voltage components of the electrical grid, including stations and high voltage lines typically utilized to transmit large volumes of electricity closer to load centers. On Idaho Power's system, transmission equipment is considered to be facilities at or above 138-kV, with an additional sub-transmission component comprised of facilities at 46-kV and 69-kV.

Q. How have the transmission-related investments grown since the completion of the limited scope case in 2024 that included incremental capital investments, Case No. IPE-E-24-07 ("2024 Limited Scope Case")?

A. Of the $941.5 million in infrastructure anticipated to be placed in service in 2025, approximately $201.3 million reflects investment in the Company's transmission system.

Q. What drives investment in the transmission system?

A. Growth and reliability are the primary drivers of the transmission investments reflected in the Company's request in this case. Growth-related projects typically include either the construction of new transmission facilities or the expanded capacity of existing facilities. Reliability projects typically include the proactive reconstruction or replacement of aging facilities, additional facilities to increase resiliency, and compliance related projects. My testimony will discuss 13 transmission-related major projects expected to be complete in 2025, 11 of which are required to address aging infrastructure, one is growth-related, and one supports security enhancements.

Transmission Line Rebuilds and Repairs

Q. What is the largest transmission investment necessary to address aging infrastructure expected to be complete in 2025?

A. With a cost of approximately $16.5 million, the largest transmission investment expected to be complete

in 2025 and included in Idaho Power's request in this case is the second phase of the rebuild of a portion of Line 423. In fact, three of the transmission investments necessary to address aging infrastructure are associated with transmission line rebuilds: (1) Line 423, (2) Line 412, and (3) Line 902. Delaying the rebuilds could result in higher maintenance and repair costs should the structures need replacement individually, while also potentially reducing reliability, and are therefore critical to the continued delivery of safe, reliable electric service to customers.

Q. Is the rebuild of Line 423 the same project that was included in the Company's 2024 Limited Scope Case?

A. Yes. However, the amounts included in the 2024 Limited Scope Case were associated with the first phase of the project, and the portion expected to be complete in 2025 is associated with a second phase of the project. Line 423 is a 138-kV line that runs from Ontario to the Quartz substation, south of Baker City in Oregon. The rebuild project is associated with the Huntington to Quartz 138-kV portion of Line 423 ("Huntington-Quartz line") and is being performed in two sections (1) the approximately 24 miles from the Quartz substation to the Nelson Tap/Ash Grove substation ("phase one"), and (2) the

approximately 16.5 miles from the Nelson Tap/Ash Grove substation to the Huntington substation ("phase two").

Q. What drove the need for the rebuild of the Huntington-Quartz portion of Line 423?

A. The rebuild of the Huntington-Quartz line was required due to the age of the existing line and resulting reliability issues. When evaluating potential outage sources, it was noted that due to the age of the lines, this section was constructed between 1949 and 1951, shield wires had not been installed and therefore lightning was likely contributing to the performance issues. Thus, the Company engaged POWER Engineers, Inc. ("POWER Engineers"), to perform a study to analyze the entire Ontario to Quartz 138-kV line, and specifically the Huntington to Quartz section to determine if a rebuild on the line would increase reliability.

Q. What were the results of the analysis?

A. POWER Engineers used a lightning performance software, analyzing three cases, each with two different footing resistance assumptions: (1) the existing wood structure with no shield wires, (2) a new wood structure with two shield wires, and (3) a new steel structure with two shield wires. The results indicated that the overall line performance would be significantly improved with the addition of shield wires and further improvement is

expected if steel structures were used in combination with the addition of shield wires.

Q. Is Idaho Power replacing the existing wood structures with steel structures?

A. Yes. The Huntington-Quartz line rebuild will include the replacement of 286 structures from the Huntington substation to the Quartz substation with tubular steel 138-kV structures with shield wire and optical ground wire for fiber optic communications. Due to the age of the existing wood structures, they did not have space for the addition of shield wires. Moreover, because the Huntington-Quartz line was identified as being in a wildfire prone area, the project was prioritized, and grid hardening performed as part of the rebuild. Grid hardening includes the use of steel structures for resiliency against wildfires and improved customer reliability.

Q. How does the addition of shield wires improve reliability?

A. Shield wires are installed above the conductors for the purpose of channeling lightning strikes to ground, which helps to prevent or minimize damage to power lines and equipment, avoid major outages on the line, and mitigate maintenance and repair costs. Phase two of the rebuild of the Huntington-Quartz line, with a total cost of approximately $16.5 million and an anticipated in service

of July 2025, is necessary to ensure Idaho Power continues providing safe, reliable electric service to its customers.

Q. What drove the need for the rebuild of Line 412?

A. Similar to Line 423, nearly half of the structures and crossarms on the approximately 30-mile Boise Bench to Emmett 138-kV section of Line 412 were built in 1947. Having first been identified in 2016 as a rebuild priority to address reliability issues, the Boise Bench to Emmett 138-kV section of Line 412 was routinely experiencing extensive maintenance repairs, emergency repairs and hillside erosion. Due to its location within the red wildfire risk zone along the Boise foothills, the line was also identified in Table 14 of the Company's 2025 Wildfire Mitigation Plan and needed steel structures for resiliency against wildfires and improved customer reliability. The rebuild of the Boise Bench to Emmett 138-kV section of Line 412 is estimated to be complete in October 2025 for a total cost of approximately $12.5 million.

Q. Is the rebuild of Line 902 the same project that was included in the Company's 2024 Limited Scope Case?

A. Yes. However, the amounts included in the 2024 Limited Scope Case were associated with one phase of the project, and the portion expected to be complete in

2025 is associated with a second phase of the project. Line 902 is one of the three 230-kV transmission lines that run from the Boise Bench substation to the Midpoint substation. Line 902 has been connected to and split into many line sections by station additions over the years, and is now comprised of the Midpoint to Justice, Justice to Mountain Air Wind Tap, Mountain Air Wind Tap to Rattlesnake, Rattlesnake to DRAM, and finally DRAM to Boise Bench segments. Line 902 was originally built over 70 years ago, with 478 of the original structures from 1947 in place. The rebuild project will occur in four phases, the second of which is included in the Company's request in this case, the approximately four-mile Boise Bench substation to DRAM substation section ("Boise Bench to DRAM").

Q. Is the Boise Bench to DRAM portion of Line 902 in a wildfire prone area?

A. Yes. All four phases of the Line 902 rebuild fall within the wildfire prone areas as identified in Idaho Power's Wildfire Mitigation Plan, including the Boise Bench to DRAM section. Therefore, all four phases of the line rebuild will utilize steel structures for resiliency against wildfires and to improve customer reliability. Phase two of the work to rebuild the Boise Bench to DRAM section of Line 902 is expected to be complete in October 2025 at a total cost of approximately $2.7 million.

Q. What additional transmission investments were necessary to address aging infrastructure?

A. The next two transmission investments I am going to discuss that were required to address aging infrastructure were portions of: (1) Line 906 and (2) Line 441. Lines 906 and 441 were identified as needing certain remediations during Idaho Power's comprehensive maintenance inspection. The Company follows transmission maintenance and inspection practices in accordance with the Western Electricity Coordinating Council and the North American Electric Reliability Corporation ("NERC") requirements to ensure compliance with applicable safety and reliability standards and takes proactive steps to repair or replace transmission line components on an ongoing basis as part of asset management and aging infrastructure assessments. Pursuant to its Transmission Maintenance and Inspection Plan, the Company performs line inspections to identify conditions or defects and inform, prioritize, and schedule maintenance activities. Routine line patrols are conducted annually, and the comprehensive maintenance inspections are generally performed every 10 years and include a detailed inspection of all transmission line components and a pole inspection and ground-line treatment of all wood poles in the line. When inspected, certain poles, cross arms, and insulators on both Lines 906 and 441 were found to be in

poor condition as a result of this process, and therefore identified as needing to be replaced.

Q. Where is Line 906 located?

A. Line 906, a 106 mile 230-kV line, is one of the three 230-kV transmission lines that run from the Boise Bench substation to the Midpoint substation. The work on Line 906 is expected to be complete in December 2025 at a total cost of approximately $7.8 million.

Q. Please describe Line 441.

A. Line 441 is an approximately 42 mile 138-kV line that runs from the Oxbow substation to the McCall substation in rough, high-risk terrain. The line is being repaired in two phases, and because they will both be complete in 2025, Idaho Power's request in this case is associated with both phases of the project. Both phases are expected to be complete by December 2025 for a total cost of approximately $4.2 million.

Transmission Stations Equipment Replacement

Q. You discussed the transmission line investments necessary to address aging infrastructure. What additional transmission investments are necessary to address aging infrastructure and are expected to be complete in 2025?

A. The remaining six transmission major projects necessary to address aging infrastructure are all

associated with transmission station equipment replacements due to either equipment failures or equipment beyond its expected operating life. Two of the six investments are required prior to the addition of a new 138-kV line, the Ontario to Cairo line. The 138-kV line will bring service from Ontario substation to the Cairo substation. The new line was identified as part of a corrective action plan to resolve a NERC Transmission Planning ("TPL") compliance issue. The NERC TPL are standards that include several key regulations aimed at ensuring the reliability of the bulk power system. Under TPL-001-4, the Company must establish transmission system planning performance requirements to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

Q. How was the compliance issue identified?

A. As part of the reliability studies, if the Ontario substation experienced a breaker failure that caused two transformers to go offline, the system configuration would result in just one transformer to serve the entire 69-kV system in the area. As load has grown in the area, reliability standards can no longer be met. The Ontario substation and the Cairo substation major projects were planned as the result of the reliability compliance standards.

Q. Please describe the work being performed to address the reliability issues.

A. The solution to the reliability issue was to add a new 138/69-kV source to support the existing 69-kV system. Because the existing Ontario substation was nearing capacity, a new source had to be built at a different substation, the Cairo substation, which is located in the south end of the town of Ontario. The Company is upgrading the line voltage on an existing line, and looping that line into the Cairo substation, which will require four new 69-kV breakers and two new 138-kV breakers to support the connections.

Q. What is the total investment in the Cairo and Ontario substations included in Idaho Power's request in this case?

A. Idaho Power has included in its request in this case a total investment of $9.3 million for both the Cairo and Ontario substation projects. The Ontario substation work was completed in January 2025 and the Cairo substation work is anticipated to be completed in June 2025.

Q. What are the four remaining transmission station investments necessary due to aging infrastructure you have not yet discussed?

A. The four remaining transmission station investments necessary due to aging infrastructure were made at the Blackfoot, American Falls, Kinport, and Weiser substations. First, at the Blackfoot substation, the existing 138-kV transformer was manufactured in 1953 and had exceeded its expected operating life and repair parts had become difficult or costly to procure. Further, the load tap changer on the transformer was requiring more frequent maintenance, indicating the potential for a transformer failure. In addition, the transformer relays had outdated technology, creating reliability concerns. The existing transformer relays were replaced with new protective relays and the existing bus protection relays and lockouts were replaced with new microprocessor-based protection. The Blackfoot substation equipment replacement project was completed in April 2025 and approximately $5.4 million is included in Idaho Power's request in this case.

Q. What drove the need for the American Falls substation investments?

A. The existing transformer protection relays were electromechanical relays which had exceeded their expected reliable operating lives and therefore posed an increasing risk to the system of failure. Further, the relays lacked the remote access, data archiving, and event analysis capability of modern electronic relays.

Q. What investments were made at the American Falls substation to replace the aging equipment?

A. The transformer protection relay packages were replaced, as was the supervisory control and data acquisition ("SCADA") equipment, and the 46-kV breaker, switches, and bus. The American Falls substation equipment replacement project was completed in April 2025 and approximately $3.4 million is included in the Company's request in this case.

Q. Please describe the Kinport substation major project anticipated to be complete in 2025.

A. The major project associated with the replacement of aging infrastructure at the Kinport substation involves the replacement of the air-breaks. The existing air-breaks are at the end of the expected life and no further modification or adjustments can be made to the equipment. Due to their age and challenges operating, these air-breaks pose a high risk of failure. The air-breaks are a part of three separate transmission lines that are critical to serving the Pocatello and Blackfoot areas and therefore a failure could cause outages and/or damage other equipment. Idaho Power's request in this case includes project costs associated with the Kinport substation of approximately $2.7 million with anticipated completion in June 2025.

Q. What work will be done at the Weiser substation to address aging infrastructure?

A. The Weiser substation contained equipment that was manufactured as early as 1965 and was due for replacement due to industry technological changes as well as obsolescence. Due to the increasing risk of equipment failure or mis-operation with associated risks of unnecessary or potential extended outages, the oil circuit breakers were replaced with new gas breakers and the electromechanical relays were replaced with modern digital relays. More modern digital relays also provide fault location and other data utilized for reliability purposes not available from electromechanical relays. The Company has included total project costs associated with the Weiser substation of approximately $2.6 million in the request in this case. The project was placed in-service in January 2025.

Growth-Related Transmission Investments

Q. You indicated there is one transmission-related major project Idaho Power has included in its request in this case associated with growth. Where is the work being performed?

A. Due to load growth in the Treasure Valley area, the Company was experiencing limited operations of various resources and transmission paths south of the

Treasure Valley to serve load during peak conditions. In addition, increased transmission capacity was needed for delivery of resources from the Hemingway substation, including the Hemingway battery storage resources, as well as resources from the 138-kV system, including the Kuna battery storage resources. To accommodate the growth and increased transmission capacity need, in 2025 Idaho Power is constructing two new 230-kV line terminals and one new 138-kV line terminal at the Bowmont substation, which is approximately four miles north of Melba, Idaho. The upgrades at the Bowmont substation are anticipated to be complete in December 2025 for a total cost of approximately $4.4 million.

Q. Are there any additional transmission-related investments included in Idaho Power's request in this case that you have not yet discussed?

A. Yes. One of the major projects for which the Company is requesting approval in this case is associated with threat and security vulnerability assessment investments made at one of Idaho Power's transmission substations.

Threat and Security Vulnerability Assessment Investments

Q. Please describe the threat and security vulnerability assessment investments expected to be complete in 2025?

A. Similar to the threat and security vulnerability assessment investments in Idaho Power's hydro facilities discussed in the Direct Testimony of Mr. Ryan Adelman, there is one threat and security vulnerability assessment project expected to be completed in 2025 and necessary at the Borah transmission substation. The physical security improvements are being made in accordance with the (1) NERC Reliability Standards specific to Physical Security of the Bulk Electric System and associated Cyber Systems, and (2) Idaho Power's internal risk assessment process for high and critical rate assets. These enhanced security controls at the substation will better detect, deter, delay, notify, assess, and respond to potential security threat events. Analysis of the Borah transmission substation identified the need for enhanced security controls including the installation of improved security fencing, the upgrade of the closed-circuit television ("CCTV") camera system, as well as other improved security measures.

Q. What is the total investment in the Borah transmission substation included in Idaho Power's request in this case?

A. The Company is requesting in this case to include approximately $10.5 million associated with the Borah substation threat and security vulnerability

assessment investments. The work is expected to be completed in June 2025.

Q. Do the transmission-related major projects you discussed demonstrate a prudent approach to investment in the Company's transmission system and support Idaho Power's transmission-related rate base included in this case?

A. Yes. In just one year, the Company is investing over $201.3 million in its transmission system. Idaho Power is constantly evaluating the capacity needs, resiliency, and reliability of its transmission system, ensuring that the electrical grid is stable and in compliance with NERC standards. Further, the Company is dedicated to the safety of its customers and communities as evidenced in the continuously evolving Wildfire Mitigation Plan. Idaho Power works to reduce the risk of wildfire ignition through the implementation of core mitigation approaches, such as grid hardening of the electrical system, as evidenced by the transmission-related investments I discuss in my testimony.

II. DISTRIBUTION INVESTMENTS

Q. Please describe how the Company defines the distribution-related portion of the electrical grid.

A. Distribution refers to equipment at 34.5-kV and below, including lower voltage lines, substations, and transformers that are typically utilized to provide

electricity at the lower voltages required by the majority of end-use customers.

Q. How have the distribution-related investments grown since the completion of the 2024 Limited Scope Case?

A. Of the $941.5 million in infrastructure placed in service over this period, approximately $207.1 million reflects investment in the Company's distribution system.

Q. What factors contributed to investment in Idaho Power's distribution system over this period?

A. Growth in the distribution system can be directly tied to the addition of new customers, as every new primary or secondary service level customer, requires some form of additional distribution equipment. In addition, similar to certain components of the Company's transmission system, Idaho Power has also undertaken a number of key projects to proactively harden its distribution system to maintain and improve reliability in light of aging infrastructure. These investments not only include the proactive replacement of aging infrastructure, but also the improvement of the distribution system through the installation of modern technology. Next, I will discuss the distribution-related major projects expected to be completed in 2025. I will specifically discuss the largest distribution project the distribution portion of the WRV Project, later in my testimony, providing an overview of

its long and complex regulatory history. Aside from the WRV Project, there are 10 distribution-related major projects expected to be complete in 2025, five of which are required to address aging infrastructure and five are growth-related.

Aging Infrastructure-Related Distribution Investments

Q. What is the largest distribution investment necessary to address aging infrastructure expected to be complete in 2025?

A. With a cost of approximately $5.2 million, the largest distribution investment associated with the replacement of aging infrastructure and included in Idaho Power's request in this case is the replacement of two transformers at the Julion Clawson substation. The two existing transformers were manufactured in 1967. The load tap changers, which adjusts output voltage without interrupting the load, on two transformers had been performing inadequately, and therefore impacting reliability. The transformers had been repaired multiple times in the last few years and because of their age it was becoming difficult to obtain parts for repairs of either transformer and troubleshooting and repairing them had become challenging. In addition, the feeders were carrying more load over the years, and it was becoming difficult to

shift load elsewhere without overloading other equipment, creating reliability concerns.

Q. Aside from the reliability issues, were there any additional benefits associated with the transformer replacements?

A. Yes. The existing 28 megavolt amperes ("MVA") transformers were upgraded to 44.8 MVA transformers which will provide operational flexibility and more capacity to handle higher peak loads. In addition, they are more modern, reliable transformers and therefore easier to maintain and repair. Absent the larger transformers, mobile transformers would need to be brought in to carry the load of the existing transformers during maintenance or when repairs are made. The replacement of the transformers at the Julion Clawson substation is expected to be complete in December 2025.

Q. What additional major projects will the Company be completing in 2025 to proactively harden its distribution system to maintain and improve reliability in light of aging infrastructure?

A. Three of the distribution-related major projects associated with aging infrastructure include the upgrade of three distribution stations: the Durkee substation, the Bannock Creek substation and the Caldwell substation. As part of an analysis performed to determine

alternatives to replacing the existing Line 209, a 69—kV line with structures dating back to 1927, it was determined that removal of most of Line 209 and the serving of loads via other sources was the most economical solution. Part of that solution included the rebuilding of the Durkee substation, an existing 69-kV substation, to a 138-kV substation. The new Durkee substation will connect to an existing nearby 138-kV line, allowing for the removal of the aging Line 209.

Q. What does the rebuild of the Durkee substation entail?

A. Installation of a new 138-kV air-break switch, power transformer, a dead-end structure, busbars, and conductors will be made at the Durkee substation. Also, a control building, communication equipment, concrete for foundations, and fencing will be added. The work is scheduled to be complete in October 2025 for a total cost of approximately $3.6 million.

Q. What drove the need for the upgrade of the Bannock Creek distribution station?

A. The Bannock Creek distribution station, located in the middle of the Fort Hall Reservation, was constructed in 1962 through 1963 and still contains some of the original equipment. The principal operating equipment, including the oil-filled breakers and relays and switches

are all the original equipment and the transformer were manufactured in 1969. The open-backed relays, the auxiliary current transformers, and the control cables were corroded. The concrete foundations, especially the 13-kV bus foundations, are badly decomposed, and the transformer foundation has settled requiring ongoing releveling. Finally, because of their age, the motor-operated air-break switches outside the station fence do not function properly during cold periods. In an effort to improve reliability in light of aging infrastructure, in 2025, Idaho Power will be updating the Bannock Creek station.

Q. What upgrades will be made at the Bannock Creek distribution station?

A. First, the Company will be converting the power source to 138-kV to improve reliability and reduce long-term maintenance costs on the existing 46-kV line currently serving the station. The yard will be expanded, concrete foundations replaced, and the control building replaced. A nearby 138-kV tap will be extended into the station and new terminal structures installed. The existing transformer will be replaced with a 138/12.5-kV transformer being removed from the Linden station. New breakers, controls and switches will complete station renovation. In total, the Bannock Creek distribution station infrastructure improvements are expected to be completed in

November 2025 for a total cost of approximately $3.6 million.

Q. Why is the Caldwell substation in need of an upgrade?

A. Similar to the Bannock Creek distribution station, the Caldwell substation was in need of a new control building because the existing building was too small to house the necessary upgraded equipment. The existing relays have reached the end of their life and have been unreliable over the last few years because the contacts have become tarnished and do not allow the relay to reset properly after being in the lockout state. Further, the electromechanical feeder breaker relays do not have the Hot Line Hold functionality that allows for feeder maintenance, nor do they have fault data recording that is used for protection and reliability analysis. The entire protection and control package will be removed, and the new control building will house new panels for the transformer protection, metering, and controls. Total project costs associated with the upgrades at the Caldwell substation included in the Company's request in this case are approximately $2.6 million. The work was completed in February 2025.

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Q. Please describe the final major project necessary for distribution system hardening to maintain and improve reliability.

A. The final distribution-related major project necessary to address aging infrastructure is associated with the Siphon substation equipment. Like the Bannock Creek distribution station, the Siphon substation has oil breakers that are no longer supported by the manufacturer and repair parts had become difficult or costly to procure. Having been in service since 1972, the equipment was at risk for failure which could lead to customer outages. With a total project cost of approximately $2.0 million, the Siphon substation upgrades include the replacement of the breakers and getaway cables, including the extension of the fence to accommodate the new getaway cables. The upgrades at the Siphon substation are anticipated to be completed in May 2025.

Growth-Related Distribution Investments

Q. What is the largest growth-related distribution investment expected to be complete in 2025?

A. With a cost of approximately $7.3 million, the largest distribution investment associated with growth and included in Idaho Power's request in this case is associated with work at the Vallivue substation. Projections indicated that the transformer capacity would

exceed the planning capacity by nearly six percent in the summer of 2025. The Company had already transferred two separate loads in an attempt to offload the transformer and had no additional adjacent transformer or feeder capacity available. With the average growth rate of over 5.6 percent in the urban area for which the Vallivue substation serves, primarily attributable to residential development, it was determined the substation needed to be expanded to allow for more capacity.

Q. What additions are planned for the Vallivue substation to accommodate the growth?

A. With work expected to be complete in June 2025, a new 44.8 MVA transformer is being added, new metalclad, the transfer of an existing feeder to the new metalclad, and two new feeders will be added. One feeder will add 1.5 miles of second circuit to the existing distribution line and the second feeder will add two miles of second circuit to an existing line. A feeder tie will be added to connect one of the new feeders to an existing feeder. Finally, a control building will be added to house SCADA, communication and high voltage side devices. The Vallivue substation additions are expected to be complete in June 2025.

Q. What other distribution stations require investments that are driven by growth?

A. Idaho Power's request in this case includes four additional distribution substations where investments are being made to accommodate growth: the Artesian substation, the Lansing substation, the Stoddard substation and the Halfway substation. Similar to the Vallivue substation, the transformer at the Artesian substation was exceeded the planning capacity in the summer of 2024 and growth in the area was approximately one percent annually. Because there is no available adjacent transformer or feeder capacity to offload the existing transformer, a second transformer will be added at the Artesian substation. Along with the installation of a second 46-kV transformer, a capacitor bank will be installed to complement the new transformer, providing reactive power to improve voltage stability, and the existing feeder relays that are over 60 years old will be replaced. Yard improvements will be made to accommodate the expansion and a new pre-manufactured control building installed. The work is expected to be complete in December 2025 with total project costs of $6.7 million.

Q. What investments will be made at the Lansing substation to accommodate growth?

A. The feeder at the Lansing substation was forecasted to exceed the planning capacity in the summer of 2025. Residential growth in this developing rural area is

over six percent annually and with no available adjacent feeder capacity to offload the Lansing substation feeder, additions were planned. A second metalclad will be installed along with two new feeder getaways, distribution circuits and lines that carry power out of the substation. To accommodate the additions, distribution lines coming into the station will be rebuilt and a second circuit will be added to one of the existing distribution lines. The Lansing substation investments are estimated to be approximately $5.3 million with work to be completed in December 2025.

Q. Was the Stoddard substation also signaling transformer or feeder capacity in excess of the planning capacity criteria?

A. Yes. Like the Lansing substation, the feeder at the Stoddard substation was forecasted to exceed the planning capacity in the summer of 2025 and residential and commercial load in the area was growing over nine percent annually. Multiple load transfers had been made in an attempt to defer substation additions but there were no more options available. A new 138-kV transformer will be added to the substation along with a second metalclad with two additional getaways. Two new distribution lines will be installed, their connection requiring a reconfiguration of an existing distribution line and the transferring of

existing load on a separate line to the new Stoddard distribution line. Finally, a tie switch will be added to balance load between two existing Stoddard distribution lines and a second load transfer will occur to offload a separate existing Stoddard distribution line.

Q. What is the total cost of the Stoddard substation additions necessary to accommodate growth?

A. The investments necessary at the Stoddard substation, which are identified as two different major projects in the Company's request in this case, separated between stations and distribution line costs, are estimated to be approximately $6.7 million. The distribution line work is anticipated to be complete in June 2025 and the stations work is expected to be completed by December 2025.

Q. What investments are required at the Halfway substation?

A. The Halfway substation is expected to exceed the planning capacity in the winter of 2025-2026. With an average growth trend of 1.6 percent annually, and no available adjacent feeder capacity to offload the feeder, it was determined the transformer needed to be replaced with a larger 14 MVA transformer. The station will be expanded, and along with the new transformer, the following equipment will be added: three new bus supports, new disconnects and fuses, a new distribution structure, and

new control boxes. With total project costs estimated to be approximately $3.1 million, the Halfway substation upgrades are planned to be completed in October 2025.

Q. Do the distribution-related major projects you discussed demonstrate a prudent approach to investment in the Company's distribution system and support Idaho Power's distribution-related rate base included in this case?

A. Yes. In just one year, the Company is investing $207.1 million in its distribution system. Idaho Power's thoughtful and proactive approach to investing in its distribution system has resulted in improved reliability metrics over the past decade as detailed in Mr. Adam Richins testimony. In addition, the Company is investing to accommodate growth within the Idaho Power's service area, ensuring the distribution system is equipped to provide safe, reliable service to customers now and in the future.

III. WOOD RIVER VALLEY RELIABILITY PROJECT

Q. Please describe the WRV Project.

A. Idaho Power's WRV Project includes a combination of electric distribution, transmission, and substation work, in which the Company will bury or rebuild existing distribution lines as well as construct a new overhead and underground transmission line between the Wood River substation in Hailey and the Ketchum substation in

northeastern Ketchum. The new transmission line and related facilities will provide a redundant source of energy into the northern portion of the Wood River Valley, including the communities of Ketchum and Sun Valley and portions of Blaine County (collectively referred to as the "North Valley").

Q. What drove the need for the WRV Project?

A. The North Valley contains the resort communities of Ketchum and Sun Valley as well as the Sun Valley ski resort. Currently, the North Valley is served by the Wood River and Ketchum substations, which are connected to the Company's transmission system by a single-source, 12.4 mile, 138-kV radial line that was built in 1962 with wooden poles. If the line experiences sustained outages, the outages may be lengthy because access to repair the line is impeded by residential development, rough terrain, and aged construction roads in many areas. Further, the mountainous terrain limits vehicle access, impedes equipment set-up, and contributes to avalanche threats. Ultimately, the need to construct the WRV Project was to: (1) increase reliability to the area by providing a redundant source of energy, and (2) reconstruct the existing and aging 138-kV radial transmission line without long-term disruption of service to the North Valley.

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Q. Does the Company have standard business practices it follows for determining when construction of a redundant transmission line is needed?

A. Yes. Idaho Power generally initiates and constructs a second transmission source and transformer when a substation peak load is projected to exceed 40 megawatts ("MW"). With peak loads of about 60 MW at the Ketchum and Elkhorn substations[1], coupled with the winter tourism population in the North Valley, the need for a second transmission line was strongly supported. Multiple transmission sources are standard practices that Idaho Power implements to reduce the likelihood of sustained outages. Additionally, the Company installs distribution circuit tie switches, where adjacent circuits are available, to reduce the duration of sustained outages on the radially sourced distribution system.

Q. Were there any alternatives to the redundant transmission line component of the WRV project?

A. No. Reconstruction of the existing line, which was required whether a redundant transmission line was constructed or not, was not feasible absent long-term outages without building either a redundant transmission line or a temporary line that would be removed after

[1] The Elkhorn substation is located between the Ketchum and Wood River substations, via a tap connection on the existing Wood River to Ketchum line.

construction because of the extreme disruption of service required by the reconstruction.

WRV Project Background

Q. Prior to commencing work, did Idaho Power perform any community outreach and invite public participation regarding the plan for the WRV Project?

A. Yes. In 1995, the Company first undertook an extensive public involvement process regarding the proposed construction of the WRV Project. At the conclusion of the process, Idaho Power carefully evaluated the input received from the area's public officials and citizens. The general response at that time was that, despite the unavoidable risk of an outage to the existing transmission line, the proposed new transmission line should not be built. The reasons for the public opposition included the difficulty of finding an acceptable route for the transmission line, aesthetic impacts, perceived health and safety concerns, and the requirement that local funding of incremental costs of placing part or all the line underground would be required. The project was put on hold indefinitely and Idaho Power's previous Certificate of Public Convenience and Necessity to construct the line was cancelled.[2]

[2] *In the Matter of the Application of Idaho Power Company for an Amended Certificate of Public Convenience and Necessity No. 272*, Case No. IPC-E-95-06, Order No. 26107 and cancelled Certificate No. 272 (Aug. 1995); Case No. U-1006-89, Order No. 11315 and Certificate No. 272 (Feb. 1974).

Subsequently, in 2004, Idaho Power initiated several Community Advisory Committees (“CAC”) and undertook a comprehensive, cooperative transmission planning exercise with the communities and leaders across its service territory. These committees were created to provide a cooperative effort between the Company and the communities it serves in developing an outline for prioritized improvements and additions to Idaho Power’s transmission and substation infrastructure. One of those, the Wood River CAC, was convened in 2007 and developed the Wood River Valley Electrical Plan ("WREP"), a comprehensive plan for future transmission facilities in the Wood River Valley.

Q. Did the WREP include some form of the WRV Project?

A. Yes. The WREP included construction of the redundant 138-kV transmission line between the Wood River and Ketchum substations. The WREP was updated in 2011 after additional deliberations and extensive public outreach, and in 2012 the CAC reconvened to provide additional input for planned open house events. In 2014, both the City of Ketchum and the Ketchum Energy Advisory Committee were invited to join the CAC, which reaffirmed the need for a second energy path into the North Valley. While most of the parties generally agreed upon the purpose and need for the redundant transmission line, the consensus opinion was that

a feasible route could only be obtained and permitted if at least a portion of the line was underground. However, the parties were unable to reach agreement about the funding and payment of any incremental cost difference between an overhead, or least-cost alternative, and an underground, or higher-cost build.

Q. Did Idaho Power provide an option for undergrounding a portion of the WRV Project such that no incremental cost recovery from the local jurisdictions would be required?

A. Yes. The proposed line route and facilities included a 138-kV overhead transmission line from the Wood River substation, north along Highway 75, to an underground transmission transition point near Elkhorn Road, and then underground to the Ketchum substation. These proposed facilities would follow the same path as the existing distribution lines, replacing them and minimizing the aesthetic impact. The route was economically equivalent to the Company's standard construction configuration and therefore would not require any additional incremental cost recovery from the local jurisdictions.

CPCN for the WRV Project

Q. You indicated Idaho Power had previously filed a request for a CPCN for a new transmission line to serve the North Valley area but withdrew the request. Did the

Company file a subsequent request for a CPCN following community consensus on a feasible route that included Idaho Power's proposed solution that would not require incremental cost recovery from local jurisdictions?

A. Yes. On November 8, 2016, the Company filed Case No. IPC-E-16-28, requesting the Commission find that the new 138-kV transmission line and related facilities to provide redundant service from the Wood River substation into the Ketchum substation was needed, and further requesting the Commission grant a CPCN for construction of the line as proposed and agreed upon by the local jurisdictions. The Commission issued Order No. 33872 on September 15, 2017, granting Idaho Power's request for a CPCN for a second 138-kV line, approving the requested route of overhead transmission from the Wood River substation to the transition point near Elkhorn Road, then underground transmission to the Ketchum substation.

Q. At the time the CPCN was issued, had the Company received the local permits necessary for construction of the new 138-kV line?

A. No. Prior to the CPCN proceeding, Idaho Power submitted an application for a Conditional Use Permit ("CUP") to the Blaine County Board of Commissioners ("County Board"), which was ultimately denied. Subsequent to the issuance of the CPCN, the Company filed a new CUP

with the County Board to seek out a mutually acceptable route configuration that was consistent with the CPCN route and acceptable to Blaine County, with the opportunity to mutually agree to certain micro-siting of facilities, and for the County Board to request additional undergrounding should it identify a method to fund the additional incremental cost of such undergrounding.

Idaho Power then carried out extensive public involvement and local permitting efforts relating to the transmission line project and, although lengthy, ultimately came to an agreement with the County Board on a line route configuration, as well as a surcharge mechanism to fund the incremental cost of additional undergrounding by Idaho Power's customers in Blaine County.

Final WRV Project Route Configuration

Q. What changes were made to the line route configuration that required the establishment of a surcharge mechanism?

A. Following filing of the new CUP application in November 2017, Idaho Power worked with the Blaine County Planning and Zoning ("P&Z") Commission, with engagement from the County Board, and lengthy public hearing processes, conducting extensive analysis of the micro-siting options identified by the P&Z Commission. The CUP application was approved on January 15, 2019, though no

specific route for the line was approved. While several parties appealed this decision, the County Board ultimately affirmed the P&Z Commission's CUP grant on appeal, with the condition that "the entire transmission line be undergrounded from the Wood River Substation north to the City of Ketchum.[3] However, recognizing it could be difficult to secure the required funding to bury the entire transmission line, the decision left open the possible consideration of "an overhead transmission line in this area."[4]

Securing funding to underground substantial portions of the line did prove difficult, although the County Board explored a variety of options, including passing a bond or government grants. The County Board, with consultation from the P&Z Commission, prioritized portions of the line and facilities for undergrounding. To cover the cost of the incremental undergrounding, the County Board asked Idaho Power to develop a surcharge mechanism that would be placed on Blaine County customers' electric bills.

Ultimately the new line configuration, referred to as the Owl Rock Road Route, was agreed upon by all parties involved in the P&Z and CAC efforts, and included the burial of: (1) an additional 1.4 miles of transmission,

[3] County Board's June 2019 Decision on Appeal.
[4] *Id.*

located to the south from Elkhorn Road to near Owl Rock Road, and (2) the existing distribution line for approximately 8 miles along the planned route along Buttercup Road to Highway 75. The transmission line would include overhead construction from the Wood River substation to the underground transition point at Owl Rock Road. Additionally, rather than place the existing distribution lines as under-build on the new overhead transmission structures, the existing distribution lines along the route would be buried. This will both reduce the height of the transmission poles and reduce the number of lines in the air as the transmission line will have three energized wires while the existing distribution line has between three and six energized wires and one neutral wire.

Q. Did the County Board approve the CUP for the Owl Rock Road Route?

A. Yes. On December 22, 2020, Idaho Power filed an application to the County Board for CUP approval of the Owl Rock Road Route funded by a surcharge mechanism to be placed on Blaine County customers' electric bills. The County Board approved the CUP for the Owl Rock Road Route on March 9, 2021. Under this CUP, the County Board modified the "all underground" condition for the WRV Project and replaced the language with a condition that the CUP was contingent on partial undergrounding as decided on with the

Owl Rock Road Route. This final CUP from the County Board gave Idaho Power authority to move forward with an application with the Commission for approval of a modified line route CPCN based on the Owl Rock Road Route, as well as authority to develop a surcharge that would be used to collect the incremental costs of undergrounding from Blaine County customers.

Q. Please describe the intent of the surcharge mechanism.

A. As I discussed earlier in my testimony, to recover the incremental costs of undergrounding the section of transmission and distribution lines prioritized by the County Board, the Company was asked by the County Board to develop a monthly surcharge to be applied to Idaho Power's Blaine County customers' bills over an estimated 20-year period.

Q. Did the Company receive approval from the Commission for the changes to the line route configuration and resulting surcharge mechanism?

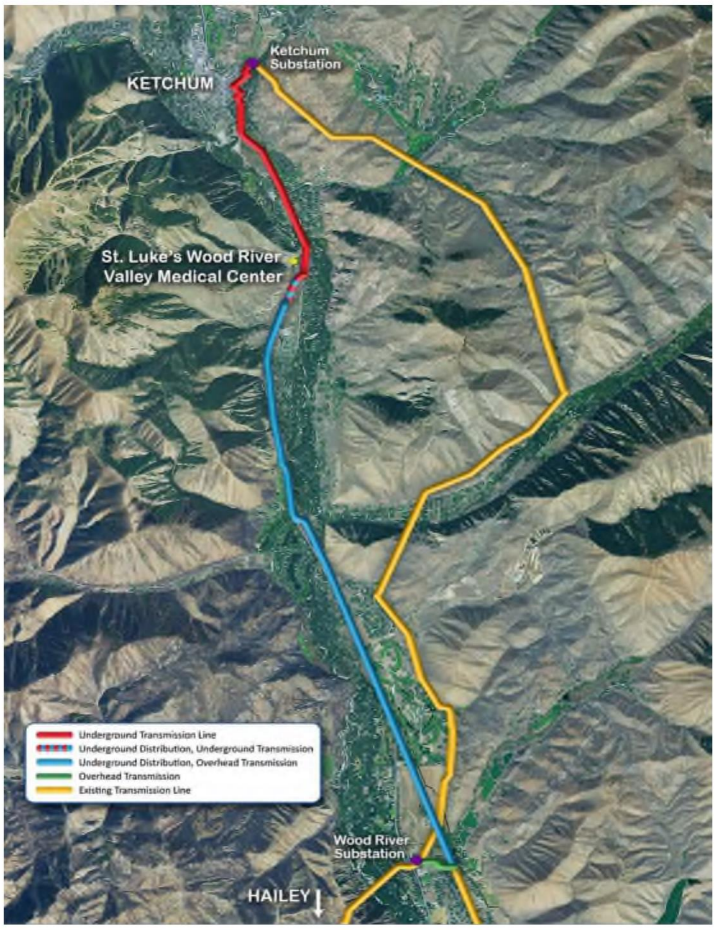
A. Yes. On June 28, 2022, in Case No. IPC-E-21-25, the Commission issued Order No. 35452, finding the modified line configuration for the WRV Project and implementation of a surcharge mechanism were fair, just, and reasonable.[5] The Commission issued an amended CPCN to

[5] Case No. IPC-E-21-25, Order No. 35452 at 16 (June 28, 2022).

reflect the new line route configuration on August 2, 2022. Figure 1 below is the Owl Rock Road Route, identifying the transmission line and line segments to be buried.

FIGURE 1

WRV PROJECT



WRV Project Costs

Q. What is the status of the WRV Project?

A. In the fall of 2023, work began on the distribution line portion of the WRV Project and continued until the weather prohibited progress. Construction resumed again in the spring of 2024, paused again when weather

prohibited progress, and resumed in 2025. Work is anticipated to be complete on the distribution line portion by November 2025.

Q. The distribution undergrounding is a portion of the broader WRV Project. What work is being completed in November 2025?

A. Work on the WRV Project began with the undergrounding of approximately eight miles of the existing distribution line along Buttercup Road and Highway 75, to allow the future transmission line to be built with shorter transmission poles to meet county height requirements. To prepare for undergrounding of the distribution line, crews first excavated a duct bank and made multiple bores along the eight-mile route. Next, the distribution line is installed in the duct bank and equipment is installed to connect existing customers.

Q. Has Idaho Power included the costs associated with the distribution line portion of the WRV Project, which is anticipated to be completed in November 2025, in the Company's request in this case?

A. Yes. However, the Company has reduced the total project costs by the estimated incremental undergrounding costs of distribution, as those costs will be recovered from Idaho Power's Blaine County customers only through the surcharge mechanism upon completion of

both the distribution and transmission portions of the project.

Q. You indicated the Company reduced the WRV Project costs associated with the distribution line included in Idaho Power's request in this case by an estimate of the incremental undergrounding costs. Why was an estimate used as opposed to actual costs?

A. Order No. 35452 acknowledged the Company's methodology for computing the estimated incremental grounding costs. Because the distribution line configuration Idaho Power would have constructed under a standard construction configuration was not built, the Company cannot identify the precise costs it would have incurred under the hypothetical scenario. That is, the request for proposals issued for the work to be performed or materials to be procured was based on a different distribution line configuration and therefore Idaho Power cannot compute with certainty the portion of the costs that would have been incurred under a different distribution line configuration.

Q. How did Idaho Power develop the incremental cost estimate?

A. To estimate the incremental costs associated with the modified distribution line configuration, the Company built a cost estimate associated with a comparable

overhead distribution line rebuild with a standard construction configuration which entails replacement of all distribution line equipment, including overhead wires and pole mounted equipment, except for most of the distribution poles. Costs were added to reflect: (1) the overhead distribution work being performed on an energized system, (2) the replacement of a portion of the existing wood poles with taller, steel poles as required by the line design, and (3) the addition of distribution intersect poles that would have been required for the distribution under-build. Finally, Allowance for Funds Used During Construction, overheads, and a contingency were applied to the total project costs as is standard when developing a project cost estimate.

Q. What are the WRV Project costs included in the Company's request in this case?

A. Net WRV Project cost of $11.8 million are included for recovery in this case from all customers, which reflects estimated project costs less the amount that will be recovered through the separate WRV Project surcharge.

Q. In Case No. IPC-E-24-07, Idaho Power included in its request costs associated with the distribution line portion of the WRV Project. Is this the same portion of the project the Company is requesting recovery of in this case?

A. Yes. However, while initially proposed to be included in Idaho Power's request in Case No. IPC-E-24-07, when it became clear that, due to circumstances outside of the Company's control, the distribution portion of the line would not be fully completed in December 2024 as previously expected, in rebuttal testimony, Idaho Power proposed to remove the amounts from the request. With the work nearing completion, the Company has again included the costs associated with the distribution line portion of the WRV project in this case.

IV. MOBILE WORKFORCE SYSTEM INVESTMENT

Q. Please describe the investment necessary for support of Idaho Power's mobile workforce system.

A. The Company's mobile workforce system enables the electronic dispatching of work to crews and electronic acknowledgement of the completion of orders, allowing for the real-time processing of customer-request or outage driven work through mobile devices. Idaho Power currently uses the CGI Technologies and Solutions Inc. ("CGI") PragmaCAD and PragmaLINE solutions to serve the mobile workforce system. However, beginning in 2023, the current CGI server and data base would no longer be supported and no enhancements were available. Absent the mobile workforce system, the Company would revert back to the inefficient processing of orders manually via phone or paper. The

existing software however was coupled with the Company's Outage Management System, which was scheduled to be migrated to the single vendor platform as part of the grid modernization efforts and would require decoupling as part of the migration. As a result, the software solution for the mobile workforce system was planned for implementation coincident with the migration of the Outage Management System.

Q. What work does the PragmaCAD migration require?

A. In addition to the software migration, the decoupling of the PragmaCAD system from the Outage Management System requires the building of PragmaCAD-specific databases and servers. This approximately 15-month process includes the migration, design, and configuration followed by testing, verification, training and deployment. Total project costs associated with the software migration included in Idaho Power's request are approximately $2.8 million and the project was completed in April 2025.

Q. Does the PragmaCAD migration demonstrate a prudent approach to investment in the Company's system?

A. Yes. The decoupling of the PragmaCAD from the Outage Management System and subsequent migration of the PragmaCAD software was necessary to support the mobile workforce and the Company's continued delivery of safe,

reliable electricity to customers.

V. IDAHO POWER'S WILDFIRE MITIGATION EFFORTS

Q. How does the Company work to mitigate wildfire risks?

A. Idaho Power deploys a variety of wildfire risk mitigation activities through its Wildfire Mitigation Plan ("WMP"), which was developed in response to the increase in frequency and intensity of wildfires seen across the western United States in recent years. In 2019, the Company first developed the WMP to identify areas within the Idaho Power's service area exposed to higher levels of wildfire risk. As an action plan for Company operations, the WMP includes best practices for mitigating wildfire risk that guide operational, personnel, and communication practices before, during, and after wildfire season.

Q. What is contributing to the growth of western wildfires in recent years?

A. A variety of factors have contributed to a greater number of destructive wildfires, including climate change, increased human encroachment in wildland areas, historical land management practices, and changes in wildland and forest health, among other factors. In 2024, Idaho saw its most active fire season in recent history. The National Interagency Fire Center ("NIFC") recorded 252 wildfire starts and 1,509,455 acres burned in or near Idaho

Power's service area during the 2024 season[6] with 996,762[7] acres of the total acreage referenced above burned in the State of Idaho. While the number of fire starts was slightly above the 30-year average of 235, the number of acres burned in or near Idaho Power's service area almost doubled the 30-year average of 860,725.[8] Development of the 2025 WMP came on the heels of this active 2024 fire season and, drawing from its experiences, Idaho Power conducted a comprehensive evaluation of its entire wildfire program including activities, tools, and personnel, and identified several critical measures to strengthen and enhance its existing efforts. These items fall into four categories: Quantifying Wildland Fire Risk, Situational Awareness, Wildfire Program & Personnel, and Enhanced Vegetation Management.

Q. What are the Company's plans to strengthen the quantification of wildland fire risk?

A. Assessing and monitoring wildfire risk is the cornerstone of Idaho Power's wildfire mitigation efforts. Beginning in 2025, the Company is transitioning to a wildfire risk modeling platform that will give Idaho Power more granular insight into wildfire risk across the

[6] Idaho Power's 2025 Wildfire Mitigation Plan, pg. 13.
[7] National Interagency Coordination Center – Wildland Fire Summary and Statistics Annual Report 2024, pg. 44.
[8] Idaho Power's 2025 Wildfire Mitigation Plan, pg. 13.

Company's service area, allow Idaho Power to incorporate weather modeling into risk assessments, and help the Company produce updated risk maps of its service area and transmission corridors. Idaho Power will also expand its fire spread simulation modeling to gain deeper insight into fire behavior and the potential consequence of wildfire ignitions within the Company's service area. Additionally, Idaho Power will be investing in a variety of tools and databases to help the Company assess the efficacy of its wildfire mitigation efforts. Idaho Power anticipates the costs of advanced wildfire risk modeling tools to enhance wildfire mitigation efforts to be approximately $2 million in 2025.

Q. How will Idaho Power improve its situational awareness associated with wildfire risk?

A. Situational awareness plays a vital role in the Company's ability to adequately prepare for and operate during times of heightened wildfire risk. Each wildfire season, through its own experience as well as those of other utilities, Idaho Power learns more about how to enhance situation awareness through a variety of means. For the upcoming fire season, the Company has identified four areas for expanded situational awareness efforts: (1) contracting for the evaluation and validation of the data collected through the Idaho Power-specific weather tool,

(2) pursuit of a waiver from the Federal Aviation Commission to operate drones beyond the visual line of sight, (3) commence an aerial drone inspection pilot project, and (4) expand the contract for standby helicopter service. At an estimated annual cost of approximately $900,000, these enhanced situational awareness efforts will aid in the preparation for, and operation during, the wildfire season.

Q. What improvements will Idaho Power be making to strengthen and enhance its wildfire mitigation program and personnel?

A. One of the key lessons learned from the past year is that wildfire work is truly a year-round effort that requires dedicated staff to prepare for, manage, and learn from each wildfire season. To strengthen Idaho Power's wildfire mitigation efforts, the Company will hire additional personnel to support critical functions essential for reducing wildfire risk and enhancing system safety. The total cost of the new positions in 2025 is estimated to be approximately $1.1 million.

Q. How will Idaho Power enhance its vegetation management efforts?

A. Vegetation management is both imperative to the Company's wildfire mitigation efforts and a source of significant challenge. The availability of qualified labor

has diminished while demand for vegetation management services has grown across the Western United States. To help address these challenges, Idaho Power has hired a three-person internal vegetation management crew to help reduce ongoing pruning costs, improve production levels, and mitigate rising expenses associated with contracted services. Additionally, the Company will continue to invest in Enhanced Vegetation Management practice in wildfire risk zones. Vegetation management continues to represent the largest single cost category in Idaho Power's wildfire mitigation activities, with an estimated incremental cost of $19.2 million in 2025.

Q. Do you believe the Company's wildfire mitigation efforts demonstrate a prudent and proactive approach to mitigating wildfire risk?

A. Yes. Idaho Power's WMP presents holistic and prudent strategies to improve safety, reliability while balancing affordability for customers and the communities the Company serves. Idaho Power continues its grid hardening efforts to protect against wildfires and other natural emergencies. In addition, to reduce wildfire risk, the Company is expanding situational awareness capabilities, further enhancing vegetation management programs and upgrading risk modeling practices.

VI. CONCLUSION

Q. Please summarize your testimony.

A. As evidenced by the continued growth in transmission and distribution investments, the Company continues its thoughtful and prudent approach to construction and maintenance of its transmission and distribution systems to ensure Idaho Power maintains a safe and reliable system, while also making great strides to mitigate wildfire risk.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF MITCH COLBURN

I, Mitch Colburn, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Mitch Colburn. I am employed by Idaho Power Company as the Vice President of Planning, Engineering and Construction.

2. On behalf of Idaho Power, I present this pre-filed direct testimony in this matter.

3. To the best of my knowledge, my pre-filed direct testimony is true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 30th day of May 2025, at Boise, Idaho.

Signed: 

MITCH COLBURN