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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2015 INTEGRATED RESOURCE PLAN.	)	**CASE NO. IPC-E-15-19**
	)	**COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's Application.

BACKGROUND

On June 30, 2015, Idaho Power Company filed its 2015 Integrated Resource Plan (IRP). The IRP is a status report on a utility's ongoing, changing plans to adequately and reliably serve its customers at the lowest system cost and least risk over the next 20 years. The IRP should explain the utility's present load/resource position, the utility's expected responses to possible future events, and the role of conservation in those responses. The IRP should also discuss "any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand-side and supply-side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering

cost, availability, lead time, reliability, risk, etc.) as future events unfold." *See* Order No. 22299. The IRP should separately address:

- "Existing resource stack," by identifying all existing power supply resources;
- "Load forecast," by discussing expected 20-year load growth scenarios for retail markets and for the federal wholesale market including "requirements" customers, firm sales, and economy (spot) sales. This section should be a short synopsis of the utility's present load condition, expectations, and level of confidence; and
- "Additional resource menu," by describing the utility's plan for meeting all potential jurisdictional load over the 20-year planning period, with references to expected costs, reliability, and risks inherent in the range of credible future scenarios.

Id. The Commission requires the utility to update the IRP every two years, allow the public to participate and comment during the IRP process, and implement the IRP. *See* Order Nos. 22299 and 25260.

In its Application, the Company explains that its 2015 IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and an action plan that details how the Company intends to implement the IRP. The IRP filing consists of four documents: (1) the 2015 IRP; (2) Appendix A – Sales and Load Forecast; (3) Appendix B – Demand-Side Management 2014 Annual Report; and (4) Appendix C – Technical Appendix.

The Company notes that it incorporated stakeholder and public input into its IRP by working with an Integrated Resource Plan Advisory Council (IRPAC) consisting of various stakeholders. Besides holding 12 IRPAC meetings, the Company also held public working group meetings to discuss energy efficiency, solar resources, and coal resources. The Company also notes that it is presenting the IRP to the public at different community meetings, to civic groups, and through seminars as requested.

The Company explains that the 2015 IRP's primary goals are to: (1) identify sufficient resources to reliably serve growing energy demands over the 20-year planning period; (2) ensure the selected resource portfolio balances cost, risk, and environmental concerns; (3) give equal and balanced treatment to supply-side resource and demand-side measures; and (4) involve the public in the planning process.

STAFF REVIEW

Staff actively participated in the IRPAC and believes the Company's IRP satisfies the Commission's requirements as specified in Order No. 22299. Although Staff has recommendations that would improve the Company's IRP process and conclusion, Staff believes the current IRP achieves the goals referenced above and is an improvement over the 2013 IRP. Staff particularly supports the variety of portfolios developed and modeled for this IRP, which included a host of resource retirement and replacement scenarios, alternatives to Boardman to Hemingway (B2H), and expanded energy-efficiency and demand-response resources. Staff also supports the Company's proposed pilot projects, which include solar Photovoltaics (PV) to address distribution feeder voltage loss, ice-based thermal energy storage, and community solar.

In addition, the Company modeled Clean Air Act (CAA) Section 111(d) compliance possibilities, stochastic risk, and at the request of stakeholders, provided a year-to-year price variability risk assessment for each portfolio, as well as a tipping point analysis to evaluate how declining capital costs for utility-scale solar PV and pumped hydro generation effect total portfolio costs. Although the 2015 IRP emphasizes the quantitative analytical process, the Company cites qualitative risk factors as the reason for selecting the preferred portfolio that the quantitative analysis did not find to be either least cost or least risk.

Load and Resource Balance

The Company's system peak and load forecasts reflect continued economic improvement in the Company's service territory. The IRP anticipates the number of customers will grow from 515,000 in 2014 to 711,000 in 2034, mainly due to net in-migration from other states. In addition, the Company expects average energy use to increase by 1.2 percent per year, and peak hour demand to increase by 1.5 percent per year. The IRP predicts 1.3 percent residential load growth, commercial load growth of 1.0 percent, irrigation load growth of 0.5 percent, and industrial load growth of 2.0 percent, and additional firm load growth of 0.6 percent. Similar to customer count projections, the customer class growth projections reflect improving economic conditions.

The load and resource balance shows the Company has no energy-related deficits throughout the planning period. A capacity deficit is expected to occur in 2025, which steadily increases through the next 9 years of the planning horizon. Without more resources, the peak-hour capacity shortfall grows from 14 megawatts (MW) in 2025 to 786 MW in 2034. The

largest capacity deficits occur in the summer months when irrigation load coincides with residential and commercial air conditioning load. The Company continues to use 70th percentile water conditions and 70th percentile average load for energy planning. For peak-hour capacity planning, the Company uses 90th percentile water conditions and 95th percentile peak-hour load.

Demand-side Management (DSM)

The Company convened two Energy Efficiency Working Group meetings to discuss stakeholder concerns about demand-side management (DSM) program delivery, the Company's Conservation Potential Assessment (CPA), energy efficiency modeling in the IRP, and quantifying the value of transmission and distribution investments deferred by energy efficiency.[1]

Conservation Potential Assessment (CPA)

Staff previously expressed concern about the significant gap between the amount of "economic" (or cost-effective) energy efficiency potential identified in the Company's CPA and the sub-set of efficiency potential believed to be "achievable" based on program participation assumptions. This gap impacts the IRP because the Company's load forecast historically has deducted "achievable" energy savings identified in the CPA. The remaining load is then met using supply-side resource portfolios evaluated according to cost and risk.

During the first workshop, the Company's third-party consultant presented the CPA's preliminary results. These results showed that program participation assumptions had been adjusted to more closely align with the Northwest Power and Conservation Council's ramp rates, which assume 85 percent of economic potential is "achievable." Since regional utilities consistently meet efficiency targets based on the Northwest Power and Conservation Council's ramp rates, and the Company almost always exceeds targets based on more relaxed program participation assumptions, Staff believes the CPA's updated ramp rates improve on previous CPAs because they more realistically estimate DSM resource potential.

However, the Company's CPA screens energy efficiency potential for cost-effectiveness based on a measure's total cost and not the Company's cost to acquire the resource. In practice,

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[1] In Errata to Order No. 33161, the Commission directed parties to address issues raised by Staff and other parties in the context of the Company's next IRP filing. Order No. 33365 found it reasonable for the Company to have "deferred DSM program delivery discussions to the EEAG." Order at 12.

this means the CPA excludes cost-effective measures, which limits the potential DSM resources considered in the IRP. Including costs for DSM resources beyond the Company's costs does not constitute equal treatment when compared to supply-side resources. Staff continues to believe that "the IRP should analyze only utility costs."[2]

Modeling Energy Efficiency in IRPs

A main topic at the Energy Efficiency Working Group meetings was the Company's method for including energy efficiency in its IRP planning process. Stakeholders questioned whether deducting "achievable" energy savings from the Company's load forecast meets the IRP's goal of providing equal and balanced treatment to supply-side and demand-side management resources. In response, the Company stated that deducting DSM from the load forecast before considering any supply-side resources gives DSM resources preferential treatment. Staff does not agree with the Company's view. By deducting "achievable" potential estimates from the load forecast, the amount of DSM in every resource portfolio is identical and static, regardless of the portfolios' other characteristics or the range of possible future scenarios.

At the Company's request, Staff presented a comparison of how different Idaho utilities' incorporate DSM in their IRP processes. As explained below, Staff concluded that PacifiCorp and Avista model energy efficiency differently than the Company.

PacifiCorp's CPA identifies the technical potential and uses the Northwest Power and Conservation Council's ramp rates on achievability to determine that 85 percent of the technical potential is "technically achievable." By including 85 percent of the technical potential, PacifiCorp allows a greater amount of DSM to be modeled against supply-side resources. The "technically achievable" potential is organized into 27 separate supply curve "cost bundles." PacifiCorp's IRP modeling software (System Optimizer) includes each DSM cost-bundle as a resource and compares them simultaneously with supply-side resources across a variety of risk scenarios. Importantly, PacifiCorp's CPA does not determine the cost-effectiveness of the Company's DSM resources. Instead, System Optimizer decides which resources—both demand and supply-side—are economic based on each future scenario. PacifiCorp's method is similar to that of the Northwest Power and Conservation Council and Puget Sound Energy.

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[2] Staff Comments, IPC-E-13-15, at 9.

Avista's 2015 IRP adopted similar methodology. However, instead of 85 percent, Avista includes 100 percent of all technical potential in its resource selection model, PRiSM, and rather than creating cost-bundles, Avista includes each measure as a distinct resource in PRiSM, which selects resource combinations specifically designed to meet a variety of load and risk scenarios.

Staff believes modeling demand-side resources simultaneously with supply-side resources could improve the Company's methodology in two ways. First, it provides more equal treatment of both resource types. Second, it recognizes that the value of demand-side resources is not static, but fluctuates based on the Company's alternate resources and scenarios. For example, the value of DSM in a high gas and high carbon scenario increases relative to conventional supply-side models. A resource selection model in which all resources compete against each other adapts to meet the requirements of differing scenarios. In contrast, using the same amount of DSM in each portfolio based on a fixed measure of cost-effectiveness assumes that the value of DSM should not change under different scenarios.

Deferred Transmission and Distribution

The Energy Efficiency Working Group meetings also discussed including the value of deferred transmission and distribution from energy efficiency investments in avoided cost calculations. PacifiCorp, Avista, and the Northwest Power and Conservation Council all include this value in their avoided costs. The Company has "committed to continuing to investigate" this benefit,[3] and the Commission has encouraged the Company to complete its investigation and report its findings to stakeholders.[4]

Dynamic Pricing Programs

Like the 2013 IRP, the 2015 IRP did not consider reducing peak load through expanded dynamic pricing. In the 2013 IRP case, Staff recommended that the Company investigate how dynamic pricing could reduce peak loads. The Company responded to this recommendation by stating that it is "conducting a study to determine customer behavior and revenue impact of the residential time-of-day-pilot plan" and "will continue to evaluate dynamic pricing options . . . to determine the appropriate time for implementation."[5] The Company presented the results of its

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[3] Idaho Power's 2015 Integrated Resource Plan, at 48.
[4] Order No. 33365 at 11.
[5] Idaho Power Company's Reply Comments, IPC-E-13-15, at 22.

Time of Use (TOU) study to the EEAG in February 2015. Unfortunately, the study was not informative because the Company's "quasi-experimental design"[6] did not involve a random sample of customers. Instead, the voluntary TOU plan primarily encouraged participation from structural winners, i.e., from people whose bills would decrease without any change in behavior. When soliciting participants, the Company encouraged customers to consult the rate comparison tool on its website to determine if their bills would go up or down under the TOU rate schedule. Because the Company encouraged participation by people who would not need to change their consumption patterns to benefit from the new rate schedule, the TOU study found no statistically significant change in energy consumption and only a small reduction in peak usage. As a result, these findings are not helpful for informing future dynamic pricing plans.

Portfolio Design

The 2015 IRP analyzed portfolios that were primarily developed during a Portfolio Design Workshop in early January. The IRP analyzed 23 portfolios, which grouped resources into categories based on resource similarities. These categories included a status quo portfolio,[7] a few portfolios without any coal retirements, portfolios with North Valmy retirements ranging from 2019 to 2025, Jim Bridger retirements ranging 2023 to 2032, a combination of North Valmy and Bridger retirements, and a set of portfolio alternatives to the B2H transmission line. Except for the alternative to B2H portfolios, all portfolios included B2H with an online date between 2021 and 2025.

The Company took considerable effort to construct and analyze a wide range of resource portfolios based on stakeholder feedback. However, the resource combinations in each portfolio were primarily based on the Company and stakeholders' resource preferences. For example, solar advocates proposed portfolios with heavy PV penetration, the Company proposed portfolios that included the B2H transmission line and natural gas plants, and conservation advocates proposed coal-retirement portfolios. The portfolios competed against each other in terms of cost and risk under a variety of future scenarios, but the selection method may not (nor is it designed to) ensure that any of the portfolios analyzed combine the resources best suited to meet the most likely future. Staff believes a better portfolio design approach would forecast

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[6] Idaho Power, Time of Day: Impact Study Results, Fall 2014, at 3.
[7] Not compliant with CAA Section 111(d).

specific scenarios and then strategically select resource portfolios to mitigate the most significant and probable risks of those scenarios.

Portfolio Selection

After completing the portfolio design process, the Company analyzed the portfolios for costs and risk. The Company's analysis involved three steps.

First, fixed and variable costs were established for each of the 23 portfolios.

Second, all 23 portfolios were subjected to a CAA Section 111(d) sensitivity analysis based on three scenarios: 1) state-by-state mass-based compliance; 2) system-wide mass-based compliance; and 3) emissions-intensity compliance with building blocks. The state-by-state mass-based compliance and emissions-intensity compliance were further analyzed for 30 percent, 55 percent, and 70 percent Langley Gulch capacity factors.

Third, a representative sample of 11 portfolios based on the initial cost estimate and resource mix was selected for the stochastic risk analysis. In the risk analysis, each portfolio was subjected to a set of 100 stochastic iterations based on changes in three variables—natural gas prices, customer load, and hydroelectric variability—to determine the 20-year Net Present Value (NPV) of each portfolio to serve customer load under all 100 stochastic iterations.

In both the initial cost assessment and the CAA Section 111(d) sensitivity analysis, Portfolio 9 is the least cost portfolio.[8] *See* Attachments A and B to Staff Comments. Additionally, the subsequent stochastic risk analysis concluded that "[portfolio] 9 . . . is the least-cost portfolio for the full set of 100 iterations."[9] *See* Attachment C to Staff Comments.

As requested by IRPAC members, the Company assessed year-to-year price variability among the portfolios. The Company found that Portfolio 3, which includes a high penetration of utility-scale PV solar, had the least annual variability. The Company also conducted a Loss of Load Expectation (LOLE) analysis. The Company found that portfolios 2(a), 6(b), 8, 10, 11, and 13 were the "best performers with an LOLE under 2 hours per year over the 20-year planning horizon."[10] The Company did not indicate whether any other portfolio failed the standard.

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[8] Portfolio 9 includes the retirement of North Valmy Unit 1 in 2019, Unit 2 retirement in 2025, and B2H in 2025. See Idaho Power's 2015 IRP, at 105.
[9] Idaho Power's 2015 IRP, at 123.
[10] Idaho Power's 2015 IRP, at 139.

Although Portfolio 6(b) is not the least-cost portfolio on an initial-cost basis, or the least-risk portfolio based on a variety of futures and stochastic risk modeling, the Company selected Portfolio 6(b) as its preferred portfolio. This portfolio assumes that B2H will be completed and both North Valmy units will be retired in 2025. The portfolio does not add other resources until 60 MW of demand response and 20 MW of ice-based thermal energy storage are added in 2030, and a 300 MW combined-cycle combustion turbine (CCCT) is added in 2031.

The Company notes the unequivocal findings of its stochastic risk analysis (*see* Staff Attachment C):

> . . . [T]he lack of significant cross of lines [in the risk analysis] is a testament to the resource diversity of Idaho Power's existing portfolio and the portfolios of new resources considered in the IRP; under no set of stochastic futures is a portfolio a clear and runaway cost winner, only to be countered by a different set of futures for which it is just as clearly a losing portfolio susceptible to significantly higher costs than other portfolios.[11]

Staff agrees with this assessment because it affirms the Company's robust risk analysis. However, Staff believes the assessment undermines the Company's selection of Portfolio 6(b) as the preferred portfolio because the risk analysis finds that Portfolio 6(b) is the sixth most risky portfolio out of the eleven studied.

In defense of its preferred portfolio, the Company states: "portfolios with early North Valmy retirement performed well in the 2015 IRP analysis, analyses show favorable economics for portfolios with retirement of North Valmy Unit 1 as early as 2019. However, these portfolios carry considerable risk associated with uncertainty in:"[12]

- CAA Section 111(d) regulation, particularly on the interim compliance period beginning in 2020;
- PURPA solar, and the impact of future project cancellations on capacity additions in the early 2020s;
- regulatory acceptance of accelerated depreciation and associated rate impacts for early coal unit retirement;
- B2H's completion date; and
- retirement planning for a jointly owned power plant.

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[11] Idaho Power's 2015 Integrated Resource Plan, at 123.
[12] Idaho Power's 2015 Integrated Resource Plan, at 10.

The Company explains that the lack of resource needs before Valmy's 2025 retirement protects preferred Portfolio 6(b) from the risks associated with these uncertainties. Staff supports the Company's thoughtful consideration of qualitative risk factors. However, it is difficult to conclude that these factors justify overriding the conclusive results of the Company's risk analysis.

Of the five risk factors identified above, two—CAA Section 111(d) and PURPA—have become less uncertain since the IRP was filed. For example, the EPA's final 111(d) rule reduces Idaho's emission-reduction targets and extends the compliance period when compared to the draft rule that the Company used to assess the IRP portfolios. Furthermore, Commission Order No. 33357 limits PURPA contracts to two years, which decreases uncertainty around future PURPA projects. The final CAA Section 111(d) rules and Commission Order No. 33357 do not eliminate the risks from these factors—Idaho's implementation plan for Section 111(d) has not been determined and 320 MW of contracted PURPA solar projects have yet to be built—but the uncertainty has clearly been reduced.

A third risk factor, acceptance of accelerated depreciation for early plant retirement by regulatory agencies, is significant but may be manageable. For example, if the Company can demonstrate to the Commission an early plant shutdown with accelerated depreciation would clearly benefit customers, regulatory acceptance may become more likely given other alternatives. Staff thus believes the Company increases regulatory uncertainty by selecting a more expensive and risky preferred portfolio rather than proposing accelerated depreciation with a least cost/least risk preferred portfolio.

The fourth and fifth risk factors—uncertainty regarding B2H's online date and negotiating an offline date for North Valmy with NV Energy—are also important. In its 2013 IRP Comments, Staff recommended—but the Company did not adopt—a risk analysis to quantify the chance of B2H being delayed beyond its previous online date of 2018. The online date has now been pushed back to 2021 and is included as a qualitative risk. While B2H's online date may change, this risk affects nearly all the portfolios to some degree since only a small handful provide alternatives to B2H.

Negotiating North Valmy's retirement with NV Energy is another risk factor. Staff understands this issue is dynamic, which probably precludes public discussions about the likelihood of aligning retirement dates between the two utilities. But as an equal owner in North

Valmy, the Company is better positioned to negotiate for least-cost/least-risk operational terms than it is for resources in which it is a minority partner, such as B2H and the Bridger coal plant.

Staff believes the Company should have provided more detailed and thorough evidence about why it overrode the results of its cost and risk analyses to choose a portfolio that is neither least cost nor least risk.

Action Plan

The Company states its action plan for 2015 to 2018 includes continued permitting and planning for B2H, and investigating North Valmy retirement in collaboration with the plant's co-owner, NV Energy. The action plan also discusses ongoing permitting and planning related for the Gateway West transmission line project; evaluating how the EPA's final CAA regulations impact fossil fuel plants; pursuing cost-effective energy efficiency; amending the Federal Energy Regulatory Commission license to reduce the 50 MW Shoshone Falls project expansion from 50 MW to 4 MW scheduled to go on-line in 2019; completing selective catalytic reduction (SCR) retrofits for Jim Bridger Units 3 and 4; and beginning to evaluate the economics of SCR retrofits for Jim Bridger Units 1 and 2.

Staff believes this action plan is sufficient to implement the preferred portfolio. However, the least cost/least risk portfolio includes the retirement of Valmy Unit 1 in 2019. By implementing a 2015 to 2018 action plan that does not include specific steps to meet that goal, the Company will almost certainly miss the opportunity to implement the Company's identified least cost/least risk resource portfolio.

STAFF RECOMMENDATION

After reviewing the Company's 2015 IRP, Staff believes that the Company performed extensive analyses, gave reasonably equal consideration of supply and demand-side resources, and provided acceptable opportunities for public input, resulting in an IRP that satisfies the requirements set forth in Commission Order Nos. 25260 and 22299. Staff thus recommends the Commission acknowledge the Company's 2015 IRP.

Respectfully submitted this 5th day of October 2015.

Karl T. Klein
Deputy Attorney General

Technical Staff: Stacey Donohue

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Table 9.3 2015 IRP portfolios, NPV years 2015–2034 ($ thousands) (portfolios in green were studied in the stochastic risk analysis)

Portfolio[1]				Variable Costs	Fixed Costs[3]	Summary		
Portfolio Index (1)	Portfolio Description (2)	B2H (3)	Coal Capacity Retirement (4)	Operating[2] (AURORA) (5)	Total Fixed Costs (6)	Total Fixed + Variable Costs (7) (7) = (5) + (6)	Lowest Cost Rank (8)	Lowest Cost Relative Difference (9)
P1	Status quo w/ B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions)	✓		$4,306,018	$110,689	$4,416,707	1	$0
P9*	Valmy19_25 w/ DR, recips, B2H_25, SCCT	✓	✓	$4,489,655	$30,933	$4,520,588	2	$103,880
P11*	Bridger23_32 w/ ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW	✓	✓	$4,418,783	$130,594	$4,549,377	3	$132,670
P2(a)*	B2H_25, recips, (no coal capacity retirement)	✓		$4,461,356	$110,689	$4,572,046	4	$155,338
P8*	Valmy19_25 w/ ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW	✓	✓	$4,445,028	$129,423	$4,574,450	5	$157,743
P10*	Bridger23_32 w/ SCCT, B2H_25, CCCT	✓	✓	$4,505,955	$75,219	$4,581,175	6	$164,467
P2(b)	B2H_23, recips, (no coal capacity retirement)	✓		$4,456,215	$136,570	$4,592,785	7	$176,078
P6(b)*	Valmy25_25 w/B2H_25, DR, ice TES, CCCT	✓	✓	$4,492,228	$102,944	$4,595,171	8	$178,464
P6	Valmy25_25 w/ B2H_25, CCCT	✓	✓	$4,492,934	$111,303	$4,604,237	9	$187,529
P13*	Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT	✓	✓	$4,507,342	$100,935	$4,608,277	10	$191,570
P2(c)	B2H_21, recips, (no coal capacity retirement)	✓		$4,452,737	$164,124	$4,616,861	11	$200,154
P3*	Valmy19_19 w/ ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW	✓	✓	$4,311,661	$309,467	$4,621,128	12	$204,421
P12	Bridger23_28 w/ SCCT, B2H_25, CCCT	✓	✓	$4,541,071	$100,730	$4,641,800	13	$225,093
P18*	Valmy 21_25 w/ res PV, B2H_25, CHP, geotherm, hydro, recips	✓	✓	$4,464,898	$179,429	$4,644,327	14	$227,619
P4(c)	Valmy19_19 w/ battery, recips, B2H_21	✓	✓	$4,539,309	$105,904	$4,645,213	15	$228,506
P4(b)	Valmy19_19 w/ battery, recips, B2H_23	✓	✓	$4,528,608	$180,442	$4,709,050	16	$292,343
P4(a)	Valmy19_19 w/ battery, recips, B2H_25	✓	✓	$4,521,759	$188,424	$4,710,183	17	$293,475
P17*	Bridger23_32 w/ ice TES, PV, CHP, recips, geothermal, CCCT, SCCT		✓	$4,380,138	$332,652	$4,712,790	18	$296,083
P16*	Valmy19_25 w/ DR, recips, CCCT, SCCT		✓	$4,518,985	$197,652	$4,716,637	19	$299,930
P14	Ice TES, recips, CCCT, SCCT, (no coal capacity retirement)			$4,477,547	$263,236	$4,740,783	20	$324,075
P5	Valmy19_19 w/ CCCT, B2H_25	✓	✓	$4,482,891	$281,412	$4,764,303	21	$347,595
P15	Valmy19_19 w/ battery, recips, SCCT, CCCT		✓	$4,493,671	$311,829	$4,805,500	22	$388,793
P7	Valmy25_25 w/ B2H_25, pumped storage	✓	✓	$4,509,228	$487,899	$4,997,127	23	$580,419

Attachment A
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Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions)

		State-by-State Mass-Based Compliance			System-Wide Mass-Based Compliance	Emissions-Intensity Compliance with Building Blocks		
Portfolio	Portfolio Description	Langley Gulch at 30% Annual CF*	Langley Gulch at 55% Annual CF	Langley Gulch at 70% Annual CF		Langley Gulch at 30% Annual CF	Langley Gulch at 55% Annual CF	Langley Gulch at 70% Annual CF
P1	Status quo w/ B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)
P2(a)	B2H_25, recips, (no coal capacity retirement)	$4,572	$4,541	$4,536	$4,518	N/A	N/A	N/A
P2(b)	B2H_23, recips, (no coal capacity retirement)	$4,593	$4,563	$4,557	$4,539	N/A	N/A	N/A
P2(c)	B2H_21, recips, (no coal capacity retirement)	$4,617	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	N/A	N/A	N/A
P3	Valmy19_19 w/ ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW	$4,621	$4,563	$4,558	$4,512	$4,518	$4,490	$4,488
P4(a)	Valmy19_19 w/ battery, recips, B2H_25	$4,710	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P4(b)	Valmy19_19 w/ battery, recips, B2H_23	$4,709	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P4(c)	Valmy19_19 w/ battery, recips, B2H_21	$4,645	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P5	Valmy19_19 w/ CCCT, B2H_25	$4,764	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P6	Valmy25_25 w/ B2H_25, CCCT	$4,604	$4,571	$4,568	$4,536	$4,517	$4,485	$4,480
P6(b)	Valmy25_25 w/B2H_25, DR, ice TES, CCCT	$4,595	$4,564	$4,561	$4,527	$4,509	$4,478	$4,473
P7	Valmy25_25 w/ B2H_25, pumped storage	$4,997	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P8	Valmy19_25 w/ ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW	$4,574	$4,541	$4,538	$4,503	$4,485	$4,458	$4,455
P9	Valmy19_25 w/ DR, recips, B2H_25, SCCT	$4,521	$4,494	$4,490	$4,455	$4,438	$4,408	$4,410
P10	Bridger23_32 w/ SCCT, B2H_25, CCCT	$4,581	$4,551	$4,545	$4,545	N/A	N/A	N/A

Attachment B
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Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions) (continued)

		State-by-State Mass-Based Compliance			System-Wide Mass-Based Compliance	Emissions-Intensity Compliance with Building Blocks		
Portfolio	Portfolio Description	Langley Gulch at 30% Annual CF*	Langley Gulch at 55% Annual CF	Langley Gulch at 70% Annual CF		Langley Gulch at 30% Annual CF	Langley Gulch at 55% Annual CF	Langley Gulch at 70% Annual CF
P11	Bridger23_32 w/ ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW	$4,549	$4,511	$4,506	$4,510	N/A	N/A	N/A
P12	Bridger23_28 w/ SCCT, B2H_25, CCCT	$4,642	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	N/A	N/A	N/A
P13	Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT	$4,608	$4,577	$4,572	$4,570	$4,535	$4,505	$4,498
P14	Ice TES, recips, CCCT, SCCT, (no coal capacity retirement)	$4,741	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	N/A	N/A	N/A
P15	Valmy19_19 w/ battery, recips, SCCT, CCCT	$4,806	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P16	Valmy19_25 w/ DR, recips, CCCT, SCCT	$4,717	$4,682	$4,672	$4,530	$4,639	$4,606	$4,600
P17	Bridger23_32 w/ ice TES, PV, CHP, recips, geotherm, CCCT, SCCT	$4,713	$4,657	$4,649	$4,665	N/A	N/A	N/A
P18	Valmy 21_25 w/ res PV, B2H_25, CHP, geotherm, hydro, recips	$4,644	$4,615	$4,610	$4,578	$4,560	$4,533	$4,528

Note: Gray shaded cells not analyzed because no Valmy retirement is assumed (N/A) and/or baseline costs are too high.

* Baseline CAA Section 111(d) sensitivity.

Attachment B
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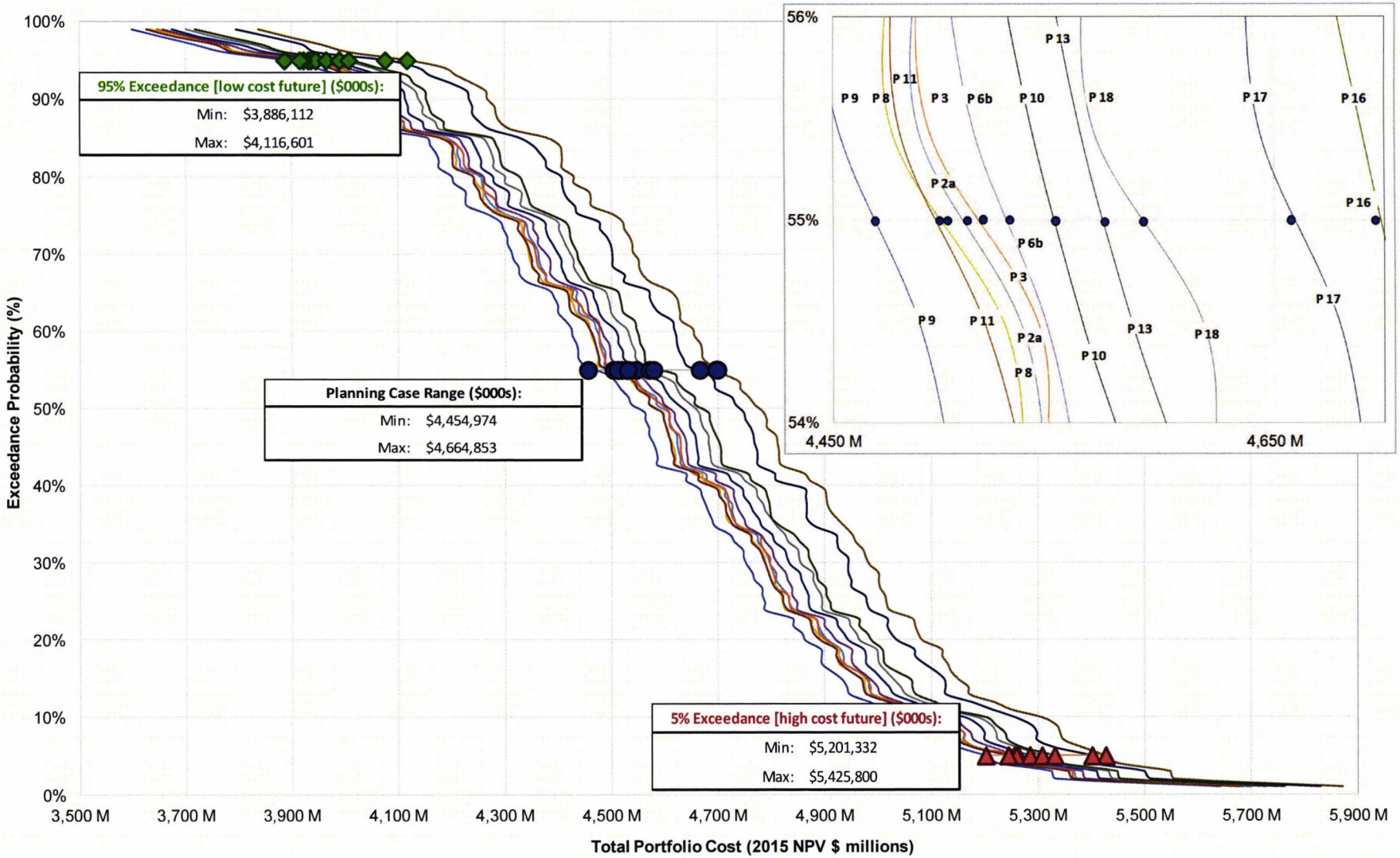

Figure 9.1 **Portfolio stochastic analysis**

Attachment C
Case No. IPC-E-15-19
Staff Comments
10/05/15

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 5TH DAY OF OCTOBER 2015, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-15-19, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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