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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A DETERMINATION VALIDATING A NORTH VALMY POWER PLANT UNIT 2 CLOSURE IN 2025.

CASE NO. IPC-E-19-18

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TOM HARVEY

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

A. My name is Tom Harvey and my business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the General Manager of Power Supply, Planning and Operations in the Power Supply Department.

Q. Please describe your educational background.

A. I have a Bachelor of Business Administration in business management from Boise State University. I also attended the University of Idaho's *Utility Executive Course* in 2011.

Q. Please describe your work experience with Idaho Power.

A. I was hired by Idaho Power in July 1980 to work in the Plant Accounting Department. From 1985 through 2009, I was the Fuels Management Coordinator and then was promoted to the Joint Projects Manager. In April 2015, I was promoted to Resource Planning and Operations Director. In January 2018, I was promoted to my current position, General Manager of Power Supply, Planning and Operations in the Power Supply Department. My current responsibilities include supervision over Idaho Power's jointly-owned coal assets, integrated resource planning, load serving operations, and merchant activities.

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

A. The purpose of my testimony is to present the results of the North Valmy power plant ("Valmy") Unit 2 closure analyses supporting a December 31, 2025, end-of-life date.

Q. What specific action is the Company requesting of the Idaho Public Utilities Commission ("Commission") in this case?

A. Idaho Power is requesting the Commission acknowledge the Company has sufficiently validated the economic retirement date of Unit 2 as December 31, 2025, as directed by the Commission in Order No. 34349.

I. AGREEMENTS AND REGULATORY APPROVALS IMPACTING VALMY OPERATIONS

Q. Please describe the Valmy plant.

A. Valmy is a coal-fired power plant that consists of two units and is located near Winnemucca, Nevada. Unit 1 went into service in 1981 and Unit 2 followed in 1985. Idaho Power owns 50 percent, or 284 megawatts[1] ("MW") (generator nameplate rating), of Valmy. NV Energy is the co-owner of the plant with the remaining

[1] For planning purposes, Idaho Power uses the net dependable capability of 262 MW.

50 percent ownership and operates the Valmy facility. NV Energy and Idaho Power (collectively, the "co-owners") work jointly to make decisions regarding Valmy. The plant is connected via a single 345 kilovolt transmission line to the Idaho Power control area at the Midpoint substation. Idaho Power owns the northbound capacity and NV Energy owns the southbound capacity of this line.

Q. What are the current agreements under which NV Energy and Idaho Power own and operate Valmy?

A. The ownership and operation of Valmy is dictated by three agreements: (1) the Agreement for the Ownership of the North Valmy Power Plant Project; (2) the Agreement for the Operation of the North Valmy Power Plant Project, both of which are dated December 12, 1978; and (3) the North Valmy Station Operating Procedures Criteria, dated as of February 11, 1993, between Idaho Power Company and Sierra Pacific Power Company, as amended by Amendment No. 1 to the Operating Procedure Criteria for Valmy Coal Diversion Procedures and Usage, dated as of January 1, 2012. Additionally, as presented in Case No. IPC-E-19-08, the co-owners entered into the North Valmy Project Framework Agreement between NV Energy and Idaho Power, dated as of February 22, 2019 ("Framework Agreement"), memorializing the terms and conditions under which either partner may elect exit of participation in Valmy. The

Framework Agreement is effective upon both co-owner's determination of satisfactory regulatory approvals.

Q. Have the co-owners received satisfactory regulatory approval of the Framework Agreement?

A. Commission Order No. 34349 deemed the Framework Agreement with NV Energy as prudent and commercially reasonable; however, approval of the Framework Agreement from the Nevada Public Utilities Commission ("Nevada PUC")[2] and the Public Utility Commission of Oregon has not yet been received.

Q. What are the current end-of-life assumptions used by the co-owners for each Valmy unit?

A. In its 2018 Update to the Life Span Analysis Process of Valmy Units 1 and 2, NV Energy recommended retirement dates of both units at year-end 2025.[3] However, on December 21, 2018, in Docket No. 18-06003, the Nevada

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[2] *Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the second amendment to its 2018 Joint Integrated Resource Plan to update and modify the load forecast, the Demand-Side Management Action Plan, the generation portion of the Supply-Side Action Plan, and the Transmission Action Plan.* Docket No. 19-05003, filed on May 1, 2019.

[3] *Application of Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy for approval of its 2017-2036 Triennial Integrated Resource Plan and 2017-2019 Energy Supply Plan, 2016 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2016-2035 Integrated Resource Plan, and the second amendment to its 2016-2035 Integrated Resource Plan and 2016-2018 Action Plan to include the acquisition of the South Point Energy Center*, Docket No. 16-07001. Updated Life Span Analysis Process in compliance with order dated February 16, 2017, filed on February 16, 2018.

PUC issued an order adopting NV Energy's 2019-2038 Triennial Integrated Resource Plan, 2019-2021 Action Plan, and 2019-2021 Energy Supply Plan, all of which included an early retirement of Unit 1 on December 31, 2021, under NV Energy's stated conditions.[4] NV Energy's stated conditions include: (1) demonstrative evidence that the three new northern PV projects and associated storage projects will achieve commercial operation by June 2022, (2) NV Energy must have adequate capacity to serve customer load, (3) there must be sufficient access to capacity and energy in western markets to mitigate cost pressure and alleviate a reduction in flexibility associated with not having power available from Valmy 1, (4) a transmission area load of 2,800 MW will trigger a reevaluation of retirement of Valmy 1, (5) accounting treatment regarding decommissioning Valmy 1 must be consistent with other retirement NV Energy generation assets, and (6) the accounting treatment regarding undepreciated book value must be consistent with the tracking accounting treatment authorized in prior dockets. The end-of-life date for Unit 2 remained at year-end 2025.[5]

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[4] *Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2019-2038 Triennial Integrated Resource Plan and 2019-2021 Energy Supply Plan,* Docket No. 18-06003 (December 21, 2018).

[5] Nevada PUC Order dated December 21, 2018, Document ID 34967.

Idaho Power, in the settlement stipulation ("Settlement Stipulation") approved by the Commission with Order No. 33771, agreed to use prudent and commercially reasonable efforts to end its participation in the operation of Unit 1 by December 31, 2019, and Unit 2 by December 31, 2025.[6]

Q. Does Commission Order No. 34349[7] address the Company's proposed cessation of Unit 2 operations by December 31, 2025?

A. During review of Idaho Power's Application in Case No. IPC-E-19-08, Commission Staff ("Staff") indicated that it reviewed the Company's Unit 2 closure analysis but did not have adequate information from Idaho Power at the time to determine whether the Company had completed a thorough review of a unit withdrawal date of December 31, 2025. In Order No. 34349, the Commission adopted Staff's recommendation that the Company use best efforts to file within 21 days of the service date of the order: (1) an analysis validating the December 31, 2025, economic

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[6] *In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates for Electric Service to Recover Costs Associated with the North Valmy Plant*, Case No. IPC-E-16-24, Order No. 33771 (May 31, 2017).

[7] *In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates for Electric Service to Recover Costs Associated with the North Valmy Plant*, Case No. IPC-E-19-08 (May 31, 2019).

retirement date of Unit 2 or (2) an analysis supporting a different economic retirement date of Unit 2.

II. <u>UNIT 2 RETIREMENT ECONOMIC ANALYSIS</u>

Q. Has Idaho Power completed the analysis supporting an economic retirement date of Unit 2?

A. Yes. The Company's analyses can be grouped into three general categories: (1) a Long-Term Capacity Expansion ("LTCE") analysis performed during the development of the 2019 Integrated Resource Plan ("IRP"); (2) a portfolio cost comparison between a 2019 Unit 2 shutdown and a 2025 Unit 2 shutdown under the planning assumptions from the 2019 IRP; and (3) a comprehensive Valmy verification for all 24 portfolios modeled in the IRP, including all costs and benefits associated with the Framework Agreement.

Q. Please describe the analysis performed concurrently with the development of the 2019 IRP.

A. The Settlement Stipulation approved by the Commission with Order No. 33771 in Case No. IPC-E-16-24 committed Idaho Power to continue to conduct Unit 2 closure analyses as part of the Company's 2019 IRP and perform a Unit 2 closure validation study to evaluate a least cost/least risk closure date. Because the 2019 IRP was in the development phase at the time the Company filed its request in Case No. IPC-E-19-08, Idaho Power relied on the newly executed Framework Agreement and associated fee schedules as an indication that there is likely no economic benefit associated with the exit of Unit 2 prior to December 31, 2025.[8] However, concurrent with the processing of Case No. IPC-E-19-08 and in conjunction with the development of the 2019 IRP, Idaho Power developed 24 resource portfolios using the LTCE capability of the AURORA model to analyze whether exiting Unit 2 prior to 2025 would benefit customers.

Q. What is the goal of the IRP?

A. The goals of the IRP are to ensure: (1) Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs over a 20-year planning period; (2) the selected resource portfolio balances cost, risk, and environmental concerns; (3) balanced treatment is given to both supply-side resources and demand-side measures; and (4) the public is involved in the planning process in a meaningful way.[9] Historically, the Company developed portfolios to eliminate resource deficiencies identified in a 20-year load and resource balance. Under this process, Idaho Power developed portfolios which were quantifiably demonstrated to eliminate the identified resource deficiencies, and

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[8] Case No. IPC-E-19-08, *Harvey, DI*, pages 21-23.

[9] 2019 Integrated Resource Plan, Case No. IPC-E-19-19, page 1.

qualitatively varied by resource type, where the varied resource types reflected the Company's understanding that the financial performance of a resource class is dependent on future conditions in energy markets and energy policy. However, beginning with the 2019 IRP, the Company began using the AURORA model's LTCE modeling capability to develop portfolios.[10]

Q. Please describe the LTCE modeling capability of AURORA.

A. The LTCE capability of AURORA produces a Western Electricity Coordinating Council- ("WECC") optimized portfolio under various future conditions, such as varying assumptions for natural gas prices and carbon costs. The WECC-optimized portfolio includes the addition of supply- and demand-side resources for Idaho Power's system while simultaneously evaluating the economics of exiting from current generation units.

More specifically, under the AURORA LTCE modeling process, the alternative future scenarios are formulated first, then the AURORA model is used to develop portfolios that are optimal to the selected alternative future scenarios. To develop optimized portfolios for the alternative future scenarios, the AURORA model selects from

[10] The 2019 IRP will be filed in Case No. IPC-E-19-19 on June 28, 2019.

a variety of supply- and demand-side resource options available to it, developing portfolios that are optimal for those given alternative future scenarios.

Q. What are the existing supply- and demand-side resource options available to AURORA?

A. Existing supply-side resources include generation resources and transmission import capacity from regional wholesale electric markets. Existing demand-side resources include current levels of demand response as well as savings from current energy efficiency programs and measures, which are reflected as a decrement to the load forecast.

Q. How does the AURORA modeling meet the planning margin and regulating reserve requirements objectives?

A. First the AURORA model will account for the capability of the existing system and then, when the existing system comes short of meeting the objectives, will select from a pool of new supply- and demand-side resources. The general iterative methodology for the LTCE logic is that for each LTCE iteration, the entire set of candidate new resource options and retirements are available to the system and the model performs the standard chronological commitment and dispatch logic under each future scenario. The model tracks the performance of all new resource options and resources available for retirement, tracking the resource costs and value based on the market prices developed in the iteration. At the end of each iteration, the LTCE logic decides how to adjust the current set of new builds and retirements, or it determines that the model has converged on a solution. The logic behind the LTCE model seeks to create a mix of resources that are most economic while adhering to future capacity needs and meeting reliability constraints.

Q. How does Idaho Power define the new supply- and demand-side resources in AURORA?

A. The pool of new supply- and demand-side resources is set by Idaho Power with input through the IRP Advisory Council process. The new resources used in the 2019 IRP AURORA modeling include solar, geothermal, wind, biomass, combined-cycle combustion turbines, simple cycle turbines, reciprocating internal combustion turbine engines, nuclear, battery storage, pumped storage, demand response, and energy efficiency.

Q. What happens once AURORA forms the portfolios?

A. Once formed, the portfolios are evaluated for operational, environmental, and qualitative considerations, and culminate into an action plan that sets the stage for the Company to economically and effectively prepare for the system needs of the future. The resulting combination of resources provides a reliable portfolio to supply cost-effective power to Idaho Power's customers over the 20-year planning period.

A. <u>LTCE Analysis</u>.

Q. Please describe the AURORA LTCE modeling scenarios performed for the 2019 IRP.

A. The AURORA LTCE modeling was performed using three natural gas and four carbon emissions adders to develop optimized resource portfolios for a range of possible future conditions, with the Boardman-to-Hemingway transmission line project and without. Twenty-four separate portfolios were developed which included varied amounts of nameplate generation additions, creating a diversity of resource mixes, including wind, solar, natural gas reciprocating engines, natural gas combined-cycle combustion turbines, demand-side management, battery storage, pumped storage, biomass, and additional acceleration of the Jim Bridger power plant unit retirements. The diversity of resource mixes in the 24 portfolios illustrates the many combinations of resources that result in a reliable system for customers at varying costs.

Q. How did Idaho Power use the 24 AURORA LTCE modeling resource portfolios to validate a Valmy Unit 2 closure of 2025?

A. Idaho Power modeled the 24 portfolios to validate a Unit 2 shutdown date of 2025. It is important to note that the logic of the capacity expansion model allowed Unit 2 to retire in 2025 or earlier in these AURORA LTCE model runs. In all 24 scenarios, Unit 2 did not shut down prior to 2025. However, these runs did not include the final costs and benefits associated with the newly executed Framework Agreement.

Based upon these initial results, to reduce model runtime during final capacity expansion runs, Idaho Power left the Unit 2 shutdown date static at 2025. Although the preliminary runs did not include the fixed costs required to keep the plant in operation or the exit fees associated with the Framework Agreement, Idaho Power did not believe the inclusion of the Framework Agreement costs and savings would result in any material impact to the modeling results.

B. <u>Portfolio Cost Comparison</u>.

Q. Did the Company compare the costs of the 2025 and 2019 shutdown scenarios?

A. Yes. To compare the net cost and benefits of an early Unit 2 shutdown, Idaho Power did an analysis using planning natural gas and carbon assumptions with the full costs and savings of the Framework Agreement included, but this time forced Unit 2 to shut down in 2019. The Company compared this portfolio cost to that of its 2019 IRP preferred portfolio, which includes a 2019 and 2025 shutdown for Units 1 and 2, respectively. The result, which is summarized in Exhibit No. 1, was a portfolio cost of approximately $95 million more than the preferred portfolio, supporting the conclusion that the net cost savings associated with an early retirement of Unit 2 would not support a shutdown of Unit 2 prior to 2025.

Q. Did the Company run a similar cost comparison by modeling a forced Unit 2 retirement for 2020, 2021, etc.?

A. No. The modeling of a 2025 exit and a forced 2019 exit provide bookends that render the modeling of the interim years unnecessary. If a Unit 2 shutdown in 2019 is $95 million more costly than a 2025 shutdown, a forced shutdown in any year between 2019 and 2025 would not result in a lower cost than the 2025 shutdown date. The 2019 shutdown date allows for the maximum amount of potential cost avoidance with respect to required capital and operations and maintenance ("O&M") expenditures; therefore, if this scenario is higher cost than the year-end 2025 shutdown scenario, a shutdown date during any of the interim years between 2020 and 2024 would not result in any additional cost savings that would support a shutdown date prior to year-end 2025.

C. <u>Comprehensive Valmy Verification</u>.

Q. Please describe the comprehensive Valmy analysis the Company performed to validate the Unit 2 2025 shutdown date.

A. In addition to the IRP analysis detailed earlier in my testimony, and the portfolio cost comparison between a 2019 shutdown and a 2025 shutdown, Idaho Power ran the capacity expansion model for all 24 portfolio scenarios with the full costs and savings of the Framework Agreement included as inputs to the model. Under this approach, the LTCE model was allowed to shut down Unit 2 in any year prior to 2025, taking into account all costs and benefits associated with an early exit; i.e., exit fees resulting from the Framework Agreement, avoided capital expenditures, and avoided O&M expense. The Valmy-specific inputs to this model are included in Exhibit No. 2.

Q. What were the results of the comprehensive Valmy model runs?

A. All 24 portfolios validated a Unit 2 closure of 2025 as the least cost option because each of the modeled scenarios shut down Unit 2 in 2025. It is important to note that this analysis included a model run that reflected the least favorable coal scenario that is most likely to result in early coal closure—the high carbon, planning gas scenario. Even under this "least favorable” coal scenario, Unit 2 was shown to be needed and cost-effective until the end of 2025.

Q. What conclusions can be drawn from these results?

A. These results indicate that, under the broad range of modeled scenarios, in no case is it economically beneficial to exit Unit 2 prior to 2025. Given the fact that these models included all expected costs and benefits associated with an early exit from Unit 2, this analysis validates year-end 2025 as the appropriate exit date for both depreciation purposes and the Company’s planned exit from the Valmy plant.

III. CONCLUSION

Q. Please summarize your testimony.

A. As directed by the Commission in Order No. 33771, Idaho Power performed Unit 2 closure analyses as part of the 2019 IRP process. The LTCE capability of the AURORA modeling affords Idaho Power the ability to produce an optimized portfolio under various future conditions, such as varying assumptions for natural gas prices and carbon costs, including the addition of supply- and demand-side resources for Idaho Power’s system, while simultaneously evaluating the economics of exiting from current generation units. The AURORA LTCE modeling produced 24 portfolios that include varied amounts of nameplate generation additions, creating a diversity of resource mixes. To validate a Valmy Unit 2 shutdown date of 2025, Idaho Power performed a LTCE analysis of the 24 portfolios. In all 24 scenarios, Unit 2 did not shut down prior to 2025, validating a December 31, 2025, end-of-life date. Further, when forcing the model to shutdown Unit 2 in 2019 (the year with the greatest potential for cost avoidance), total portfolio costs exceeded the 2025 shutdown scenario by approximately $95 million. For these reasons, 2025 is the appropriate end-of-life date for Valmy Unit 2.

Q. Does this complete your testimony?

A. Yes, it does.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada)

I, Tom Harvey, having been duly sworn to testify truthfully, and based upon my personal knowledge, state the following:

I am employed by Idaho Power Company as the General Manager of Power Supply, Planning and Operations in the Power Supply Department and am competent to be a witness in this proceeding.

I declare under penalty of perjury of the laws of the state of Idaho that the foregoing pre-filed testimony and exhibits are true and correct to the best of my information and belief.

DATED this 27th day of June 2019.

Tom Harvey

Tom Harvey

SUBSCRIBED AND SWORN to before me this 27th day of June 2019.

CHRISTA S. BEARRY
NOTARY
PUBLIC
Comm. No. 39431
STATE OF IDAHO

Christa S. Bearry

Notary Public for Idaho
Residing at: Meridian, Idaho
My commission expires: 02/04/2021

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-19-18

IDAHO POWER COMPANY

HARVEY, DI
TESTIMONY

EXHIBIT NO. 1

PORTFOLIO COST COMPARISON

($ x 1000)

	Portfolio 14 (Planning NG, Planning Carbon, B2H)		Valmy Both Units Retired YE 2019 (Planning NG, Planning Carbon, B2H)		
	Portfolio 14		Valmy YE 2019 B2H		Difference
2019	$	480,605.06	$	480,611.80	$	6.74
2020	$	476,211.97	$	476,424.78	$	212.81
2021	$	504,767.03	$	504,711.66	$	(55.38)
2022	$	490,381.66	$	516,039.80	$	25,658.14
2023	$	525,915.06	$	546,309.44	$	20,394.38
2024	$	544,763.60	$	568,150.00	$	23,386.40
2025	$	569,804.06	$	595,069.44	$	25,265.38
2026	$	556,520.50	$	561,381.06	$	4,860.56
2027	$	580,612.44	$	584,785.00	$	4,172.56
2028	$	596,907.25	$	596,480.56	$	(426.69)
2029	$	634,593.70	$	654,191.50	$	19,597.80
2030	$	659,529.30	$	668,314.00	$	8,784.70
2031	$	683,817.44	$	690,325.44	$	6,508.00
2032	$	708,074.20	$	712,151.40	$	4,077.20
2033	$	712,555.06	$	714,802.94	$	2,247.88
2034	$	733,707.50	$	738,584.50	$	4,877.00
2035	$	732,991.40	$	769,270.25	$	36,278.85
2036	$	737,929.60	$	770,152.44	$	32,222.84
2037	$	749,797.60	$	773,573.20	$	23,775.60
2038	$	795,897.44	$	799,095.50	$	3,198.06
NPV	$	5,028,310.40	$	5,123,368.80	$	95,058.40
B2H		$112,488.63		$112,488.63	$	-
Bridger Fixed Cost NPV		$0.00		$0.00	$	-
Total NPV	**$**	**5,140,799.03**	**$**	**5,235,857.43**	**$**	**95,058.40**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-19-18

IDAHO POWER COMPANY

HARVEY, DI
TESTIMONY

EXHIBIT NO. 2

O&M Impact of Early Valmy 2 Exit
Compared to 2025

	Expected Plan	O&M SAVINGS COMPARED TO V2 2025 Exit					
	Expected Plan Out V2 End of 2025	Early 1 End of 2024	Early 2 End of 2023	Early 3 End of 2022	Early 4 End of 2021	Early 5 End of 2020	Early 6 End of 2019
2019	11,433,700	-	-	-	-	-	-
2020	11,139,843	-	166,667	416,667	833,334	1,666,667	3,216,464
2021	11,140,040	-	166,667	416,667	833,334	766,888	(1,733,112)
2022	10,863,799	-	166,667	416,667	(66,494)	(1,733,160)	(1,733,160)
2023	11,052,555	-	166,667	(623,548)	(1,873,548)	(1,873,548)	(1,873,548)
2024	11,254,245	-	(899,249)	(1,899,249)	(1,899,249)	(1,899,249)	(1,899,249)
2025	11,487,088	(1,159,248)	(1,992,582)	(1,992,582)	(1,992,582)	(1,992,582)	(1,992,582)
2026	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-
CUMULATIVE O&M EXPENSES AVOIDED		(1,159,248)	(2,225,164)	(3,265,379)	(4,165,206)	(5,064,984)	(6,015,186)
NPV		(700,811)	(1,252,863)	(1,839,619)	(2,373,532)	(2,959,300)	(3,648,085)

Capital Rev Rqmt Impact of Early Valmy 2 Exit
Compared to 2025

	Expected Plan	CAPITAL REV RQMT SAVINGS COMPARED TO V2 2025 Exit					
	Expected Plan Out V2 End of 2025	Early 1 End of 2024	Early 2 End of 2023	Early 3 End of 2022	Early 4 End of 2021	Early 5 End of 2020	Early 6 End of 2019
2019	393,155	-	-	-	-	-	-
2020	646,518	-	-	-	-	-	(103,521)
2021	785,414	-	-	-	-	(58,416)	(270,530)
2022	894,715	-	-	-	(87,351)	(207,412)	(407,944)
2023	1,018,216	-	-	(77,232)	(257,480)	(370,606)	(559,557)
2024	1,089,665	-	(46,123)	(206,357)	(375,556)	(481,749)	(659,119)
2025	1,096,836	(24,989)	(121,431)	(271,203)	(429,354)	(528,613)	(694,401)
2026	1,049,871	(52,899)	(142,604)	(281,913)	(429,017)	(521,342)	(675,549)
2027	971,023	(48,926)	(131,894)	(260,741)	(396,797)	(482,188)	(624,814)
2028	892,175	(44,953)	(121,184)	(239,568)	(364,577)	(443,034)	(574,078)
CUMULATIVE INCREMENTAL CAPITAL REV RQMT AVOIDED		(171,767)	(563,235)	(1,337,014)	(2,340,132)	(3,093,360)	(4,569,513)
CUMULATIVE INCREMENTAL CAPEX EXPENSES AVOIDED		(150,000)	(477,045)	(1,102,590)	(1,876,691)	(2,437,069)	(3,497,495)
NPV		(90,652)	(307,387)	(757,442)	(1,371,158)	(1,856,455)	(2,859,072)

retirement year	**End of 2024**	**End of 2023**	**End of 2022**	**End of 2021**	**End of 2020**	**End of 2019**
Total NPV	**(791,464)**	**(1,560,250)**	**(2,597,061)**	**(3,744,691)**	**(4,815,755)**	**(6,507,156)**