Economic Benefits from Early Retirement of Reid Gardner

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Introduction

On March 29, 2012, NV Energy filed an economic analysis of the Reid Gardner coal plant with the Public Utilities Commission of Nevada.[1] As described in detail in this report, Resource Insight on behalf of Sierra Club independently analyzed NV Energy's filing and estimated the economic impact that would result from the retirement of Reid Gardner. Based on this analysis, Sierra Club determined that the retirement of Reid Gardner units 1-3 in 2011 and of unit 4 in 2013 would reduce costs to customers by an estimated $121 million dollars over a 20-year planning horizon. While some of these savings have been lost due to NV Energy's ongoing expenditures at the plant and other influences, the Sierra Club analysis estimates that the retirement of all four Reid Gardner units by 2013 would still save an estimated $59 million over a 20-year planning horizon.

The Public Utilities Commission of Nevada did not require the Company to consider in its March 29 analysis the potential savings that could be achieved by investment in energy efficiency to replace the lost capacity at Reid Gardner. Instead, the Company relied on purchases of energy and capacity from the wholesale market to replace Reid Gardner, and concluded that it would be less expensive to install BART control equipment and continue operating Reid Gardner to 2023 than to retire all four Reid Gardner units by 2013. Specifically, the March 29 analysis estimated that the 20-year present worth of revenue requirement ("PWRR") for the scenario that assumes early retirement of all four units (Case 2, hereinafter the "Retirement Case") would exceed the PWRR for the BART retrofit scenario (Case 6, hereinafter the "SIP Retrofit Case") by about $51 million.[2]

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[1] PUCN Docket No. 11-08019.

[2] NV Energy's March 29 analysis looked at six different scenarios for Reid Gardner. *See* March 29 Filing, Table 1. Case 2, the Retirement Case, assumed the retirement of Reid

Sierra Club experts at Resource Insight independently reviewed NV Energy's analysis and updated the results to reflect a greater investment in energy efficiency, which provides far more benefit to ratepayers than the Company's reliance on market purchases. Updating NV Energy's analysis to reflect this greater emphasis on energy efficiency revealed that retiring Reid Gardner would actually result in significant savings for NV Energy. Updating the Company's natural gas price forecasts and removing unnecessary capital expenses further increased these savings.

Resource Insight estimated the PWRR difference between the Retirement Case and the SIP Retrofit Case by making the following four adjustments to the Company's March 29 analysis:

- First, price forecasts for natural gas burned at the Company's gas-fired generating plant and for market purchases of power were updated to reflect current market expectations.
- Second, costs for the Retirement Case were revised to reflect the impact of replacing Reid Gardner generation with energy-efficiency savings, rather than with the market purchases assumed by the Company.
- Third, as a consequence of reliance on energy efficiency to replace Reid Gardner, the costs for a transmission upgrade assumed by the Company for the Retirement Case were deferred by ten years.
- Fourth, Resource Insight removed the costs associated with the 2012 outage at Reid Gardner 4 assumed by the Company for the Retirement Case.

In contrast with the Company's conclusion in its March 29 analysis, the Sierra Club economic analysis demonstrates that it would be less expensive to retire all four Reid Gardner units by 2013 than to retrofit the plant with BART controls and continue operation through 2023. Specifically, the Sierra Club analysis estimates that the PWRR for the Retirement Case would be about $121 million less than the PWRR for the SIP Retrofit Case.

Gardner units 1-3 in 2011, and the retirement of Reid Gardner unit 4 in 2013. Case 6, the SIP Retrofit Case, assumed that NV Energy would install the BART pollution control equipment (ROFA with Rotamix or SNCR) on units 1-3 as proposed by the Nevada State Implementation Plan ("SIP"), and operate all four units until 2023. The SIP must be approved by the EPA, which at the time of this report had not made a final determination on the BART pollution controls that will be required at Reid Gardner to meet the Regional Haze Rule.

Some of the benefits that NV Energy could have realized had it retired Reid Gardner units 1-3 in 2011 have been lost due in large part to recent capital expenses at the plant. However, the authors evaluated an alternative to the Retirement Case (the "2013 Retirement Case") that assumed retirement of Reid Gardner units 1-3 in 2013, rather than in 2011 as assumed in the Company's Retirement Case. This retirement scenario is still achievable if NV Energy acts to retire the plant by 2013. Under this alternative analysis, the PWRR for the 2013 Retirement Case would be about $59 million less than the PWRR for the SIP Retrofit Case.[3] In other words, delaying retirement of Reid Gardner units 1- 3 by two years would reduce, but not eliminate the economic benefit from early retirement.

Table 1 shows that retiring Reid Gardner in either the original Retirement Case or the alternative 2013 Retirement Case would result in a savings compared to NV Energy's proposal to continue to operate the plant.

Table 1: Adjustment to the PWRR Difference between Retirement and SIP Retrofit Cases

	20-Year Present Value (Million $)	
	Retire Units 1–3 in 2011 and Unit 4 in 2013	All Units Retire in 2013
NV Energy Analysis: PWRR Difference between Retirement and SIP Retrofit Cases	51	82
Natural Gas and Purchase Price Adjustment	(9)	(7)
Replace Reid Gardner with Energy Efficiency	(101)	(101)
Deferring Transmission Upgrades	(33)	(33)
Avoid RG4 2012 Outage Cost	(29)	–
Sierra Club Adjusted Analysis: PWRR Difference between Retirement and SIP Retrofit Cases	**(121)**	**(59)**

Natural Gas and Purchase Price Adjustments

The Company used the PROMOD production cost model to simulate the dispatch of its generating assets and to estimate market purchases for each of the Reid Gardner scenarios. A comparison of model outputs for the Retirement and SIP Retrofit Cases indicates that PROMOD replaces about 70% of Reid Gardner

[3] Thus, delaying retirement of units 1-3 by two years reduces the economic benefit from early retirement from $121 million to $59 million. About one-half of that reduction is due to the fact that this alternative 2013 Retirement Case includes the outage costs associated with the 2012 outage at Reid Gardner 4.

output with increased generation from the Company's gas-fired resources and the remaining 30% with energy market purchases.[4] See Table 2.

Table 2: Sources of Replacement Energy for Reid Gardner

	Reid Gardner Generation (GWh)	Replacement Gas Generation (GWh)	Replacement Energy Purchases (GWh)	Percent Replaced by Gas	Percent Replaced by Purchases	Percent Replaced by Gas and Purchases
2012						
2013						
2014						
2015						
2016			REDACTED			
2017						
2018						
2019						
2020						
2021						
2022						
2023						

Table 3 shows the increase in gas-fuel and market-purchase costs resulting from the replacement of Reid Gardner output with additional gas-fired generation and market purchases.

[4] The annual amounts of replacement gas generation or market purchases are calculated as the sum of monthly differences between the Retirement Case and the SIP Retrofit Case for those months of each year when Reid Gardner is running in the SIP Retrofit Case. The monthly values for gas generation or market purchases in other months may differ between the Retirement Case and the SIP Retrofit Case because of the stochastic nature of the PROMOD simulation software.

Table 3: Cost of Replacement Energy for Reid Gardner

	Replacement Gas Fuel Cost ($000)	**Replacement Energy Purchase Cost** ($000)
2012		
2013		
2014		
2015		
2016		
2017	REDACTED	
2018		
2019		
2020		
2021		
2022		
2023		

Pursuant to Procedural Order No. 5 in PUCN Docket No. 11-08019, the cost impacts reported in Table 3 are based on the January 2012 Risk Run forecast (mid-carbon price scenario) of prices for natural gas and market purchases. The January 2012 Risk Run forecast, in turn, relied on a combination of broker quotes for monthly forward prices for the December 28, 2011 trading day and a long-range price forecast developed by Ventyx in the Spring of 2011.

REDACTED

Forward prices for natural gas and power purchases have dropped sharply since the Company developed the January 2012 Risk Run forecast. As of the May 29, 2012 trading day, NYMEX settlement prices for 2013 Henry Hub natural gas futures were down about 14% compared to settlement prices on December 28, 2011.

Long-run price forecasts appear to reflect market expectations that moderate declines will persist in the future. For example, the Energy Information Administration's ("EIA") 2012 Annual Energy Outlook forecasts a Henry Hub price for 2020 that is about 4% lower than that projected in the previous year's Annual Energy Outlook.

Adjustment to the Price Forecast for Natural Gas

The authors made three adjustments to the Company's natural gas price forecast to reflect current price trends. First, broker quotes for monthly Henry Hub futures prices were updated to reflect NYMEX settlement prices for the May 29, 2012 trading day.[5] Second, the Ventyx Spring, 2011 long-range forecast of Henry Hub prices was replaced with the EIA Reference Case forecast from the 2012 Annual Energy Outlook (early release). Finally, the start date for blending of broker quotes and the long-range forecast prices was pushed back by one year from April, 2014 to April, 2015.[6]

Table 4 illustrates the impact of these three adjustments on the January 2012 Risk Run forecast of monthly Henry Hub and Southern California ("SOCAL") prices. As indicated in Table 4, the three adjustments reduce forecasted annual Henry Hub prices by 9% to 23%.[7]

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[5] The authors relied on NYMEX settlement prices from May 29, 2012 because that is the last day for trading June, 2012 Henry Hub future contracts. For the months of January through May of 2012, the authors relied on settlement prices from the last day of the prior month for trading the prompt month's Henry Hub contract (e.g., February 27, 2012 prices for March, 2012 Henry Hub contracts.)

[6] Likewise, the authors adjusted the Company's forecast of basis differentials between Henry Hub and relevant delivery points to reflect updated broker quotes, where publicly available, and for a later start for blending forecast prices. However, an updated long-range forecast of basis differentials was not publicly available, so no adjustment was made to the Ventyx basis forecast.

[7] The annual prices shown in Table 4 are the simple average of the monthly forecast prices in each year. All prices reflect the Company's adjustments for the impact of potential carbon regulations on gas prices.

Table 4: Comparison of Forecasts of Henry Hub and SOCAL Gas Prices

	Henry Hub			**SOCAL**		
	Jan 2012 Forecast ($/Mcf)	Resource Insight Forecast ($/Mcf)	Difference	Jan 2012 Forecast ($/Mcf)	Resource Insight Forecast ($/Mcf)	Difference
2012						
2013						
2014						
2015						
2016						
2017			REDACTED			
2018						
2019						
2020						
2021						
2022						
2023						

Adjustment to the Price Forecast for Market Purchases

The January 2012 Risk Run forecast derives market prices for energy purchases based on the forecast of natural gas prices. For example, the Company derives energy market prices for delivery at Mead as the product of monthly SOCAL gas prices and a market heat rate plus an adder to reflect the impact of carbon regulation on market prices. As such, the authors' adjustments to the forecasts for Henry Hub and basis prices automatically flow through to and reduce the forecast of monthly on-peak and off-peak energy market prices. No other adjustments were made to the forecast of energy market prices.[8]

Table 5 illustrates the impact of Resource Insight's gas-price adjustments on the forecast of Mead and COB energy market prices.[9]

[8] Specifically, no adjustments were made to the forecast of market heat rates or the forecast of price adders for carbon regulations.

[9] The annual prices shown in Table 5 are the hourly weighted average of the monthly on-peak and off-peak prices in each year.

Table 5: Comparison of Forecasts of Energy Market Prices

	Mead			**COB** (Delivered to SPCC)		
	Jan 2012 Forecast ($/MWh)	Resource Insight Forecast ($/MWh)	Difference	Jan 2012 Forecast ($/MWh)	Resource Insight Forecast ($/MWh)	Difference
2012						
2013						
2014						
2015						
2016						
2017				REDACTED		
2018						
2019						
2020						
2021						
2022						
2023						

As with market prices for energy purchases, the authors' adjustments to natural gas prices also automatically flow through to the forecast of capacity market prices. However, in this case, the gas-price adjustments lead to an increase in capacity prices compared to the Company's forecast.

This increase is the result of the Company's approach to forecasting long-term capacity prices. Specifically, the Company estimates the purchase price for market capacity as the total cost of new gas combined-cycle ("CC") generation (including capital, fuel, and other operating costs) less energy revenues from the sale of that generation into the wholesale market. The authors' adjustments to natural gas prices reduce both the cost of fuel burned by new CC generation and the market price of energy sales from new CC generation. However, the percentage reduction in market price exceeds that for the cost of fuel burned, resulting in an increase in the net cost of capacity.[10]

Cost Impact from Natural Gas and Market Price Adjustments

As noted above, the Company used the PROMOD production cost model to simulate the increase in fuel and market-purchase costs associated with the early retirement of Reid Gardner. Given limited time and resources, the authors did not re-run PROMOD to estimate the cost impact from its adjustments to the January

[10] This disproportionate impact is due to the difference between the assumed heat rate for new CC and the market heat rate implied by the relationship between forward energy market prices and forward gas market prices.

2012 Risk Run forecast of gas and market prices. Instead, the authors estimated the cost impact from its price adjustments based on the ratio of adjusted to unadjusted prices.[11]

Specifically, for natural gas, the authors reduced the PROMOD estimate of monthly gas costs by the ratio of the monthly SOCAL gas price forecasted by Resource Insight to the monthly gas price in the January 2012 Risk Run forecast. For example, Resource Insight forecasts a January, 2014 SOCAL gas price that is 89% of the price in the January 2012 Risk Run forecast. Thus, Resource Insight's estimate for January, 2014 of the additional gas fuel cost from early retirement of Reid Gardner is 11% less than the PROMOD estimate based on the January 2012 Risk Run price forecast.

Likewise, for energy market purchases, the authors reduced the PROMOD estimate of monthly purchase costs by the ratio of the monthly energy market prices forecasted by Resource Insight to the monthly price in the January 2012 Risk Run forecast.[12]

Table 6 summarizes the annual impact from the authors' adjustments to gas prices on the PROMOD estimate of the additional gas fuel cost from early retirement of Reid Gardner. In addition, Table 6 summarizes the annual impact of the authors' adjustments to market prices on the PROMOD estimate of the additional cost of energy market purchases from early retirement of Reid Gardner.

[11] Thus, Resource Insight's approach does not account for the potential change in gas plant dispatch in either the Retirement Case or the SIP Retrofit Case resulting from lower natural gas prices. As a result, the additional cost of gas consumption and market purchases to replace Reid Gardner may be overstated in the Sierra Club analysis, since the lower gas and market prices would likely result in reduced dispatch of Reid Gardner in the SIP Retrofit Case and thus lower gas and purchase costs to replace Reid Gardner in the Retirement Case.

[12] For the purposes of this calculation, purchases by Nevada Power are assumed to be priced at the market price at Mead, while purchases by Sierra Pacific are assumed to be priced at COB.

Table 6: Adjustments to Replacement Fuel and Energy Purchase Costs

	Adjustment to Replacement Gas Fuel Cost ($000)	Adjustment to Replacement Energy Purchase Costs ($000)
2012		
2013		
2014		
2015		
2016		
2017	REDACTED	
2018		
2019		
2020		
2021		
2022		
2023		

Finally, the authors estimated the increase in the annual cost to replace Reid Gardner capacity from Resource Insight's adjustment to the January 2012 Risk Run forecast of capacity market purchases. The derivation of additional capacity costs is shown in Table 7.

Table 7: Adjustment to Capacity Purchase Cost

	Retirement Case Open Position (MW)	SIP Retrofit Case Open Position (MW)	Difference (MW)	Adjustment to Capacity Price ($/kW−yr)	Adjustment to Capacity Purchase Cost ($000)
2012	245	–	245		
2013	92	–	92		
2014	500	–	500		
2015	545	–	545		
2016	639	82	557		
2017	701	144	557		REDACTED
2018	863	306	557		
2019	938	381	557		
2020	1,013	456	557		
2021	573	16	557		
2022	725	168	557		
2023	461	–	461		

Table 8 summarizes the present-value impact of these three adjustments on the PWRR difference between the Retirement and SIP Retrofit Cases. As shown in

Table 8, these three price adjustments in total reduce the PWRR difference by about $9 million.

Table 8: PWRR Impact of Price Adjustments (Millions of Present-Value Dollars)

Natural Gas Price Adjustment	(14.0)
Energy Market Price Adjustment	(5.5)
Capacity Market Price Adjustment	10.4
Total Adjustment	(9.1)

Replacing Reid Gardner with Energy Efficiency

The Green Energy Economics Group ("GEEG") has analyzed the potential for energy-efficiency savings in Nevada Power's service territory, indicating that a comprehensive effort by Nevada Power could reduce load by 2% per year.[13] Based on the findings of the GEEG study, Resource Insight estimated program costs and achievable savings from an aggressive ten-year energy-efficiency program starting in 2013.[14]

Table 9 compares Nevada Power's projected peak-load reductions to those that would result from an aggressive ten-year energy-efficiency program that yields annual savings of 2% of peak load. Compared to the Company's projections, an aggressive ten-year program would reduce peak load in 2022 by an additional 746 MW. With a 12% minimum reserve requirement, this additional 746 MW of peak savings would reduce capacity requirements in 2022 by 836 MW.

[13] Green Economics Group, *Electric Energy Efficiency Resource Acquisition Options for Nevada Power Company d/b/a NV Energy*, December 20, 2011. Concurrently filed with this report in PUCN Docket No. 11-08019 as Exhibit 2.

[14] Resource Insight's projections assume that program savings ramp up to 2% of load by 2015.

Table 9: Capacity Savings with an Aggressive Energy-Efficiency Portfolio (MW)

	Energy-Efficiency Peak Reduction			
	IRP 2nd Amendment	Resource Insight Forecast	Difference	**Reduction in Capacity Requirement**
2013	164	188	24	27
2014	211	284	73	81
2015	253	405	152	171
2016	296	528	232	260
2017	336	637	301	338
2018	372	740	368	412
2019	405	854	449	503
2020	431	986	555	622
2021	454	1,104	650	728
2022	467	1,213	746	836

Table 10 compares Nevada Power's projection of energy savings to those projected by Resource Insight. Compared to the Company's projections, an aggressive ten-year program would reduce retail sales in 2022 by an additional 2,598 GWh. Assuming a 5% loss factor for energy sales, this additional 2,598 GWh of savings is equivalent to a reduction in generation of 2,728 GWh.

Table 10: Energy Savings with an Aggressive Energy-Efficiency Portfolio (GWh)

	Energy-Efficiency Energy Savings			
	IRP 2nd Amendment	Resource Insight Forecast	Difference	**Reduction in Generation**
2013	514	599	85	90
2014	636	894	258	271
2015	750	1,289	539	566
2016	863	1,680	817	858
2017	970	2,026	1,056	1,109
2018	1,069	2,353	1,284	1,348
2019	1,109	2,671	1,562	1,640
2020	1,043	2,970	1,927	2,023
2021	983	3,238	2,255	2,368
2022	927	3,525	2,598	2,728

Table 11 provides Resource Insight's projection of the reduction in capacity and energy purchase costs if Reid Gardner were replaced by an aggressive energy-efficiency program. The annual reduction in capacity costs shown in Table 12 is derived as the product of the reduction in purchased capacity and capacity market price (as adjusted by the authors to account for updated natural gas prices.)[15] Similarly, the annual reduction in energy costs is derived as the product of energy-efficiency generation savings and (adjusted) energy market price.[16]

Table 11 also provides Resource Insight's projection of annual costs required to increase energy-efficiency savings to 2% of load. The GEEG study indicates that the additional cost required to increase program savings from 1% of load to 2% of load equates to a levelized cost of about 6.2 cents per additional saved kilowatt-hour (2011 dollars.) The authors used this incremental cost of 6.2¢/kWh to estimate the additional program spending required to increase annual savings from levels projected by the Company to those achievable with an aggressive energy-efficiency program.[17]

Table 11: Energy-Efficiency Program Costs and Benefits

	Capacity Savings (MW)	**Capacity Price** ($/kW−yr)	**Capacity Cost Reduction** ($000)	**Generation Savings** (GWh)	**Energy Price** ($/MWh)	**Energy Cost Reduction** ($000)	**Program Cost** ($000)	**Net Cost** ($000)
2013	27			90			5,422	
2014	81			271			16,722	
2015	171			566			35,585	
2016	260			858			54,905	
2017	338	REDACTED		1,109	REDACTED		72,300	REDACTED
2018	412			1,348			89,578	
2019	503			1,640			110,978	
2020	557			2,023			139,453	
2021	557			2,368			166,155	
2022	557			2,728			194,645	

[15] The annual reduction in purchased capacity shown in Table 11 may be less than the additional capacity savings shown in Table 9. For the purposes of calculating the reduction in capacity purchase costs, the authors assumed that capacity savings from energy efficiency would not reduce capacity purchases by more than the amount required to replace Reid Gardner.

[16] The annual energy market prices shown in Table 11 are the load-weighted average of the monthly on-peak and off-peak prices in each year.

[17] Resource Insight's analysis does not account for reductions in purchase costs from energy-efficiency savings that persist after program spending ends in 2022. The authors compensate for this understatement of program benefits by calculating annual program costs as the product of annual energy savings and the levelized cost per saved kilowatt-hour. This calculation essentially discounts the estimate of program spending in proportion to the unaccounted energy savings.

Finally, Table 11 provides the annual projection of program costs net of reductions in purchase costs. On a present-value basis, energy-efficiency program benefits exceed costs by about $101 million. Thus, the Sierra Club analysis estimates that replacing Reid Gardner with energy efficiency would reduce the PWRR difference between the Retirement Case and the SIP Retrofit Case from a *positive* $51 million to a *negative* $50 million. Put another way, investments in energy efficiency in lieu of further spending at Reid Gardner would, by itself, be expected to create savings of about $50 million.

Deferring Transmission Upgrades

The Company's March 29 analysis assumed the need for a $REDACTED transmission upgrade to allow for the import of energy from the 500 kV system to replace Reid Gardner generation on the 230 kV system when Reid Gardner retires. In the SIP Retrofit Case (all units retire in 2023), NV Energy assumed that the transmission upgrade would be in place by 2024. In contrast, in the Retirement Case (all units retire by 2013), the Company advanced the need date for the transmission upgrade to 2015.

Under the Sierra Club analysis, there is no need to advance the transmission upgrade from 2024 to 2015, since Reid Gardner generation is replaced with reductions to load on the 230 kV system rather than energy imports from the 500 kV system. Specifically, the Sierra Club analysis indicates that an aggressive energy-efficiency program would yield adequate peak-load savings between 2015 and 2023 to allow for deferral of a transmission upgrade in the Retirement Case to 2024, at the earliest.

The authors did not have access to the Company's detailed transmission studies for the purposes of estimating the impact of energy-efficiency savings on the transmission system. Instead, the impact was estimated by inference based on the Company's conclusion that a transmission upgrade was not required until 2024 so long as Reid Gardner continued operating.

According to the Company's March 29 analysis, no upgrade was required in 2023 with Reid Gardner in operation. The Company forecasts a peak load (net of DSM and load control) in 2023 of 6,113 MW. Moreover, Reid Gardner contributes 557 MW of capacity toward meeting that net peak load. Thus, based on the Company's March 29 analysis, it appears that retirement of Reid Gardner in any year prior to

2024 would not trigger the need for a transmission upgrade so long as net peak load did not exceed 5,556 MW (i.e., 6,113 MW minus 557 MW.)[18]

Table 12 provides for each year from 2015 through 2023 Resource Insight's estimate of the additional peak savings needed to reduce the Company's forecast of net peak load to the threshold value of 5,556 MW. In other words, Table 12 shows the amount of additional peak savings that would be required to avoid a transmission upgrade in the absence of Reid Gardner. As indicated in Table 12, without Reid Gardner, forecasted peak load in 2016 would need to be reduced by an additional 56 MW in order to avoid the need for new transmission in that year. In each subsequent year, the amount of additional peak savings needed to defer an upgrade by another year increases commensurate with growth in peak load.

Table 12 also shows that the additional peak savings from an aggressive energy-efficiency program far exceeds the minimum amount required to defer new transmission in every year from 2015 through 2023.[19] Thus, the Sierra Club analysis indicates that a transmission upgrade would not be required before 2024 if Reid Gardner were replaced by energy efficiency.

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[18] Reliability violations, and thus the need for transmission upgrades to resolve violations, are largely driven by energy flows during high-load hours. It is therefore reasonable to use peak loads as a proxy measure of energy requirements on the 230 kV system during peak hours. On the other hand, using the full 557 MW capacity as a proxy for Reid Gardner generation during high-load hours may overstate Reid Gardner's contribution to meeting energy requirements, since there is some probability of a full or partial outage during those hours.

[19] As discussed above, the authors projected additional energy-efficiency savings through 2022. For presentation purposes, Table 12 assumes that additional savings in 2023 are the same as achieved in 2022. In reality, the 2023 savings would likely be slightly lower than savings in 2022, as energy-efficiency measures installed in earlier years reach the end of their useful lives. However, even with this savings "decay", the additional savings from an aggressive program would likely exceed the minimum amount required to defer transmission from 2023 to 2024.

Table 12: Peak-Load Reductions Required to Defer Transmission

	Forecast Net Peak Load (MW)	Threshold Net Peak Load (MW)	Additional Peak Savings to Reach Threshold (MW)	Additional Peak Savings from Aggressive Efficiency (MW)
2015	5,528	5,556	(28)	152
2016	5,612	5,556	56	232
2017	5,667	5,556	111	301
2018	5,727	5,556	171	368
2019	5,794	5,556	238	449
2020	5,861	5,556	305	555
2021	5,918	5,556	362	650
2022	6,003	5,556	447	746
2023	6,113	5,556	557	746

Based on the Company's forecasts of revenue requirements for the $ REDACTED transmission upgrade, Resource Insight estimates that deferring the upgrade in the Retirement Case from 2015 to 2024 would reduce the PWRR difference between the Retirement Case and the SIP Retrofit Case by about $33 million.

Avoiding Reid Gardner 4 Outage Costs

The Company's March 29 analysis assumed that a major capital expenditure planned for the Spring of 2012 at Reid Gardner 4 would not be avoided by a decision to retire the unit in 2013. As a result, the Company's modeling of the Retirement Case assumed a $27 million capital expenditure in 2012.

This assumption is not reasonable. Pursuant to Procedural Order No. 5, the Retirement Case assumes that Reid Gardner units 1-3 would be retired by 2012. Consistent with the assumption that units 1-3 would be taken out of service in 2011, the Company should have assumed that the decision to retire all four units would have been made sometime prior to 2012. Consequently, it was not reasonable to assume that the Company would incur the 2012 expenditure at unit 4, after the decision had already been made to take the unit out of service in the following year.[20]

Instead, the Company should have assumed that retirement of Reid Gardner 4 in 2013 would have avoided the capital expenditure in 2012. The authors estimate that the PWRR difference between the Retirement Case and the SIP Retrofit Case, after adjusting for carrying costs, would be reduced by about $29 million if the

[20] In fact, all six scenarios modeled in the March 29 analysis assume no routine capital expenditures at Reid Gardner for the last three years of service.

2012 capital expenditure were assumed avoidable by retirement of Reid Gardner 4 in 2013.[21]

[21] However, the authors did not treat this capital expenditure as avoidable for the alternative 2013 Retirement Case, which assumes that all four units are retired in 2013.

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