Before the Louisiana Public Service Commission

APPLICATION OF CLECO POWER LLC FOR: (I) AUTHORIZATION TO INSTALL EMISSIONS CONTROL EQUIPMENT AT CERTAIN OF ITS GENERATING FACILITIES IN ORDER TO COMPLY WITH THE FEDERAL NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS FROM COAL AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS RULE; AND (II) AUTHORIZATION TO RECOVER THE COSTS ASSOCIATED WITH THE EMISSIONS CONTROL EQUIPMENT IN LPSC JURISDICTIONAL RATES	))))))))))))))	Docket No. U-32507

Direct Testimony of
Jeremy I. Fisher, PhD

PUBLIC
VERSION

On Behalf of
Sierra Club

November 8, 2013

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy Fisher. I am a Principal Associate at Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and six years of working within the energy planning sector, including work on integrated resource plans, long-term planning for utilities, states and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities. I have provided consulting services for various clients, including the U.S. Environmental Protection Agency (EPA), the National Association of Regulatory Utility Commissioners (NARUC), the California Energy Commission (CEC), the California Division of Ratepayer Advocates (CA DRA), the National Association of State Utility Consumer Advocates (NASUCA), West Virginia Consumer Advocate Division (WV CAD), National Rural Electric Cooperative Association (NRECA), the state of Utah Energy Office, the state of Alaska, the state of Arkansas, the Regulatory Assistance Project (RAP), the Western Grid Group, Western Resource Advocates (WRA), the Powder River Basin Resource Council (PRBRC), the Union of Concerned Scientists (UCS), Sierra Club, Earthjustice, GreenLaw, Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), Stockholm Environment Institute (SEI), Citizens Action Coalition, Civil Society Institute, and Clean Wisconsin.

I have provided testimony in electricity planning and general rate case dockets in Indiana, Kansas, Kentucky, Oregon, Utah, Wyoming, and Wisconsin. In addition, I have reviewed and provided analysis or comment to clients on electricity planning in Nevada, Alaska, Arkansas, California, Connecticut, Georgia, Michigan, Nevada, and West Virginia.

Prior to joining Synapse, I held a post doctorate research position at Tulane University and the University of New Hampshire examining the impacts of Hurricane Katrina on Gulf Coast forests. I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and a Sc.M. and Ph.D. in Geological Sciences from Brown University.

My full curriculum vitae is attached as Exhibit JIF-1.

Q **On whose behalf are you testifying in this case?**

A I am testifying on behalf of Sierra Club.

Q **Have you testified in front of the Louisiana Public Service Commission?**

A No, I have not.

Q **What is the purpose of your testimony?**

A My testimony reviews the application of Cleco Power LLC (Cleco or the Company) to install and operate, and receive cost recovery for pollution control equipment meant to meet obligations under the federal Mercury and Air Toxics Standards (MATS) rule. I review the economic justification provided by the Company to evaluate if the continued operation of the solid fuel units is least cost, as determined by the Company.

Q **What has the Company requested in this case?**

A Cleco has requested authorization to spend and recover $108.3 million for capital retrofits at two solid-fuel fired units: the Rodemacher 2 (“RPS2”) coal-fired facility, of which the Company will own 114 MW (after retrofits), and the Dolet Hills Power Station (DHPS), a lignite-fired facility of which the Company will own 318 MW (after retrofits). The Company has also requested authorization to retrofit the Madison 3 units at the Brame Energy Center, of which the Company owns 100%, or 660 MW.[1] The retrofits are designed to meet emissions limits for key pollutants under the federal Mercury and Air Toxics Standards (MATS).

Q When will these retrofits go into service?

A These retrofits are currently being constructed and are expected to be online in February and May of 2014 (DHPS and RPS2, respectively), before the resolution of this case.[2] The Company awarded contracts in September of 2013,[3] and has already committed quite a few resources to the construction of these retrofits. By November 2013, the Company will have already spent [redacted] at RPS2 and [redacted] at DHPS).[4]

Q What are the implications of the Company's actions to date?

A This case is effectively a rate case for a new capital revenue requirement, not just an authorization to install, as the Company's August 15, 2012 application suggests. The Company has moved well ahead of this Commission's ability to vet its spending in any meaningful way prior to the Company taking significant action. By the time the Commission is able to issue a ruling, the retrofits will be complete. As of today, the Company has likely committed to more than the amount specified in its draw schedule because engineering-construction-procurement (ECP) contracts often have penalty provisions for mid-project cancelation.

Therefore, the Company has committed either its ratepayers or shareholders to significant capital costs and, because the units the Company operates are jointly

[1] My testimony will not address the proposed retrofit of Madison 3-1 and 3-2, as the anticipated cost of retrofitting those smaller units is quite low. As of November 2013, the Company anticipates having spent about [redacted] of the total cost on the retrofits at Madison 3.
[2] See Company response to SC 3-33 (attached as Exhibit JIF-2) and Exhibit GAC-5.
[3] See Company response to SC 3-33 (attached as Exhibit JIF-2) and Exhibit GAC-5.
[4] See SC 3-32, Attachment A. Attached as Exhibit JIF-3.

controlled by other Louisiana utilities, the Company has effectively committed other utilities to a high level of spending.

This is particularly unfortunate because, as I will show, the Company's analysis is deeply flawed, missing key elements, and ultimately erroneous. In my opinion the Company has committed either its ratepayers or shareholders to significant stranded costs, and a long future of mounting capital and operational costs.

In moving forward on these retrofits, Cleco installed MATS compliance equipment well ahead of the regulatory deadline, and ahead of most other utilities in the country. In many cases, utilities are now finalizing their MATS compliance strategies and beginning work in anticipation of 2015/2016 compliance schedules. Cleco's eagerness to move ahead of the MATS deadline "to mitigate exposure to price risks"[5] unfortunately meant that it shortchanged a reasonable economic evaluation, and foreclosed on the opportunity to see how other environmental compliance obligations would evolve. During the time that the Company has moved forward with these retrofits, the electric utility industry has gained significant insight on emerging environmental rules and risks. The Company takes pains to explain why they must meet the April 2015 MATS deadline, and why this rushed compliance schedule is absolutely necessary.[6] However, as the Company acknowledges, the EPA has provided opportunities for utilities to request an additional year of compliance, to 2016. For example, on March 28, 2013, the Louisiana Department of Environmental Quality granted a compliance extension to Entergy for the R.S. Nelson plant, for its plans to install pollution controls much less complex than those planned by Cleco at RPS2 and DHPS.[7] I am not aware of any rejected petitions for extension. At the present time, the Company is likely to complete its MATS retrofits two and a half years before its latest compliance requirement.

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[5] Direct Testimony of Gregory Coco, p15, line 17.
[6] Direct Testimony of William Matthews, p6-7.
[7] See Letter from Sam Phillips, LDEQ to Donald McCrosky, Entergy Fossil Operations (Mar. 28, 2013), AI No. 19588. Exhibit JIF-4.

Q **Is the Company's analysis in this case sufficiently rigorous to support the Company's assertion of economic benefit for the retrofits?**

A No. The Company's case before this Commission is inadequate on a number of important fronts, from an inappropriate selection of replacement capacity, to a failure to evaluate critical impending environmental regulations, to simple, but important, internal inconsistencies between the Company's testimony and its analysis.

It is my opinion that the Company acted imprudently when it committed its ratepayers to over $108 million in investments[8] using a piecemeal evaluation tool with clear errors and omissions, when other comparable utilities use well-established, sophisticated evaluation models.

Q **Is there precedent for other states' utility regulators to deny recovery for environmental retrofits based on poor utility planning?**

A Yes. The Oregon Public Utilities Commission recently found that PacifiCorp (dba Pacific Power), a large utility serving five Western states, acted imprudently by installing emissions controls without a sufficiently rigorous analysis. The Commission disallowed a portion of the costs associated with all of PacifiCorp's installed emissions controls, finding that:

> Pacific Power failed to perform appropriate analyses to determine the cost-effectiveness of the investments. Pacific Power's contemporaneous cost-effectiveness analyses were demonstrably deficient, and did not demonstrate the rigorous review that a prudent utility should have performed prior to making these significant investments. [9]

Similarly, in another MATS retrofit case, the Indiana Utility Regulatory Commission levied a financial penalty on Indianapolis Power & Light (IP&L) for

[8] And committed other Louisiana ratepayers from Lafayette Public Power Authority, LEPA, and SWEPCO to an additional $166 million, or $274 million total.
[9] Oregon Public Utility Commission. December 20, 2012. In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision. Docket UE 246. Order 12-493, at p. 28. http://apps.puc.state.or.us/orders/2012ords/12-493.pdf.

poor management and for presenting a case lacking in appropriate rigor. The Commission stated:

> At the outset, we must note that IPL's initial presentation of its cost/benefit study through an overly simplistic analysis was disappointing. This choice represented a poor management decision and demonstrated a lack of due regard for the regulatory process. The proposed MATS Compliance Project is a substantial capital investment, and this Commission expects a petitioning utility to present the best evidence available at the outset of its case, in order to provide the Commission and other parties a reasonable opportunity to fully and fairly evaluate the company's proposal.[10]

Q How does the case at hand compare against the PacifiCorp and Indiana cases you've noted here?

A It is quite similar in its deficiencies. In PacifiCorp, the company had moved to install retrofits well ahead of a regulatory deadline, and in the rush to permit and complete construction, failed to rigorously review if the retrofits made economic sense. A review of relevant case studies might have prevented the Company from making an erroneous choice, since the PacifiCorp decision, and others like it, came before the Company filed its initial application in this docket. In Indiana, the modeling presented by IP&L contained numerous oversights, including several also found in this case today. However, in that case, IP&L at least reviewed its impending non-MATS environmental compliance obligations. There is such a wealth of literature and analysis on the risks to coal-fired facilities today that it is unacceptable for a utility to fail to review these costs.

Q Please describe the process that the Company used to determine which retrofits should be implemented at its solid fuel units.

A Cleco witness Mr. Richard Sharp provides an abbreviated description of the analysis constructed by the Company, which appears to have occurred in two

[10] Indiana Utility Regulatory Commission. August 14, 2013. Verified Petition of IPL for Approval of Clean Energy Projects…etc.. Cause 44242. Final Order. Page 31. http://www.in.gov/iurc/files/44242order_081413.pdf

parts. In the first part, the Company evaluated different control technologies, and in the second part, the Company reviewed the cost of implementing the control compared against the cost of retiring units and replacing the capacity and energy with natural gas combined cycle (NGCC) units.

In the first evaluation (the "compliance evaluation"), the Company reviewed a number of different strategies to meet MATS obligations, including various combinations of particulate capture, sorbent injection for control of acid gasses and mercury, and scrubbing with flue gas desulfurization (FGD). The Company relied heavily on three white papers done by Sargent & Lundy (S&L) in evaluating the technologies. The Company reviewed how each compliance strategy would perform under a range of capacity factors, and chose the lowest all-in-cost technology.

In the second evaluation (the "economic evaluation"), the Company determined how the retrofit coal units would perform against NGCC replacement units. In the economic evaluation, the Company reviewed four different operations and cost scenarios: the base case in which both DHPS and RPS2 are retrofit, the replacement of the Company's share of RPS2 with a 250 MW NGCC, the replacement of the Company's share of DHPS with a 480 MW NGCC, and the replacement of both units with a 480 MW NGCC unit. The Company determined that under a natural gas price forecast of low prices ($3/MMbtu, held constant in real terms) and high prices ($5/MMBtu), it was preferable to retrofit the coal units.

Q Do you have comments on the Company's overall evaluation structure?

A Generally speaking, the structure of the evaluation that the Company attempted to utilize here is sound, but the execution, and hence the outcome, is severely lacking. In many cases, the inputs and structure of the analysis are intrinsically biased towards the outcome ultimately selected by the Company, i.e. the retrofit of DHPS and RPS2.

Q **What elements of the evaluation are lacking?**

A In general, I'll focus on the economic evaluation, where the Company reviewed the economic performance of RPS2 and DHPS against NGCC units. In this analysis, there are multiple outstanding and critical shortcomings, each of which I'll describe in detail later.

- **Over-procurement of capacity**. The Company evaluated the retirement of RPS2 and DHPS against much larger NGCC units, resulting in a non-equivalent analysis. This analytical error significantly biases the analysis in favor of the coal retrofits.
- **Failure to evaluate base-case forecast gas prices.** The Company has only evaluated bounding cases in the price of natural gas, and has not provided a central forecast for evaluation. In excluding a central case, the Company compels the Commission to forecast natural gas prices, rather than simply presenting a likely case.
- **Failure to evaluate impending environmental regulations**. The Company did not mention, review, or model the real and significant costs of compliance with known future environmental requirements, including regulations of air pollutants, solid waste disposal, effluents into waterways, and greenhouse gases. These deficiencies significantly bias the analysis in favor of the coal retrofits.
- **Failure to evaluate an optimized solution.** The Company failed to use a capacity expansion model to seek an optimal portfolio for the replacement of RPS2 or DHPS. This deficiency likely biases the analysis in favor of the coal retrofits.
- **Failure to evaluate market purchases and sales.** The Company's modeling does not appear to reflect its participation in the Midcontinent Independent System Operator (MISO) energy market. It is unclear which solution would be favored by correcting this deficiency.

- **Model assumptions inconsistent with pre-filed testimony**. Selected inputs into the Company's evaluation model cannot be rectified against Mr. Sharp's supplemental testimony.
- **Model assumptions inconsistent with 2012 IRP**. This application was submitted shortly after the Company completed its 2012 integrated resource plan (IRP), and yet there are marked inconsistencies in the operational characteristics of the natural gas replacement units. These inconsistencies bias the analysis in favor of the coal retrofits.
- **Lack of avoided capital for near-term retirements.** The model fails to consider opportunities to avoid major overhauls and other large investments from the present day through a potential shutdown in 2015/2016. This oversight biases the analysis in favor of the coal retrofits.

Q Please describe the outcome of the Company's economic evaluation.

A Company witness Sharp provided two analyses, the first in the original September 2012 filing ("2012 analysis") and then a supplemental analysis submitted at the end of April 2013 ("2013 analysis").

In the 2012 analysis, the Company found, in an apparently decisive outcome, that retrofitting both RPS2 and DHPS was economically favorable. The Company found the present value of revenue requirements (PVRR) of retrofitting and operating RPS2 was $146 million less expensive than replacing the Company's 144 MW share with a 250 MW NGCC unit. Similarly, the Company found retrofitting DHPS was $189 million less expensive than replacing the Company's 318 MW share with a 480 MW NGCC unit. Finally, the Company evaluated the retirement of both units, and determined that retrofitting both units was $98 million less expensive than replacing the Company's combined 462 MW share with a 480 MW NGCC unit.[11]

In the 2013 analysis, the Company modified some inputs in the economic evaluation, corrected clear mistakes, and tested both high and low natural gas

[11] See direct testimony of Richard Sharp, p10-11.

prices, using a similar model structure. The Company's analysis indicated that at low gas prices ($3/MMBtu in 2012$, inflating nominally), the retrofits at RPS2, DHPS, and both units were beneficial by $117, $127, and $41 million, respectively. At high gas prices ($5/MMBtu in 2012$, inflating nominally), the retrofits were $232, $417, and $515 million more beneficial than replacement units, respectively.

Table 1. Cleco Analysis: PVRR of retrofit and retirement scenarios in 2012 and 2013 analyses (millions 2015$).[12]

	RPS2	DHPS	RPS2 & DHPS
September 2012 Analysis			
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	**$146**	**$189**	**$98**
April 2013 Analysis, $3 Gas			
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	**$117**	**$127**	**$41**
April 2013 Analysis, $5 Gas			
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	**$232**	**$417**	**$515**

Q Do the Company's economic evaluation results look reasonable?

A No. Almost immediately, the results provided by the Company both in the initial and supplemental analysis raise significant red flags. In particular, the fact that the net benefit of retrofitting both RPS2 and DHPS was lower than retrofitting each unit individually (in the 2012 and 2013 Low Gas scenarios) should have signaled an analysis problem to the Company. In the construct of electricity planning, these outcomes should have been moderately additive. In other words, if retrofitting one unit is beneficial, and retrofitting the other unit is beneficial, then unless the units undermine each other's dispatch, retrofitting both should have been more

[12] Direct testimony of Richard Sharp, Exhibit RLS-1; Supplemental direct testimony of Richard Sharp, Exhibit RLS-1-A.

beneficial than the review of each individual unit. Instead, retrofitting both is only about half as beneficial relative to a new NGCC as retrofitting either one. I'll discuss the reason for this outcome later.

Q Have you corrected the errors and deficiencies you found in the Company's modeling?

A Yes, to a limited extent based on the information and data available to me. I will describe in this testimony how I modified the Company's analysis to review the outcome:

- if the hypothetical replacement capacity was matched to the coal units appropriately;
- if the Company had included either a reasonable (or unreasonably small) carbon price in its analysis;
- if the analysis had taken into account the costs of known environmental regulations on the Company; and
- if the Company had used a reasonable baseline gas price forecast, instead of two bookend forecasts.

Q Generally, what are your findings?

A Using a baseline gas price forecast from the Energy Information Administration's (AEO) 2013 Annual Energy Outlook (EIA), I found that in a reasonable baseline scenario, both RPS2 and DHPS are anywhere from marginal to vastly non-economic. <u>Only</u> in the circumstance that there is no imposed carbon price <u>and</u> that the EPA scraps all stated plans for future regulation of air and water quality and toxic wastes, does it make any sense to retrofit these coal units. The moderate economic advantage found by the Company is completely eroded by corrections and the contemplation of reasonable risk.

The graphics below indicate the net benefit of retrofitting the Company's units in the Cleco 2013 analysis (Mr. Sharp's supplemental testimony), and with various corrections to adjust for the Company's oversized replacement capacity, various levels of carbon price risk, and other environmental regulations at both a lenient and strict level. The black bars at the top represent the Company's base case benefit (using AEO 2013 gas prices, between the Company's $3 and $5 levels), while the bars below represent changes in the analysis. Our best estimate of the actual economic benefit is represented in orange, with a balanced capacity requirement, adjustment for CO_2 using the most recent Synapse price forecast, and estimated proxy costs for upcoming environmental regulations.

In all cases, it does not take many corrections before the units become decisively non-economic. Rather than a net benefit to ratepayers, both RPS2 and DHPS pose a significant risk to Cleco's ratepayers.

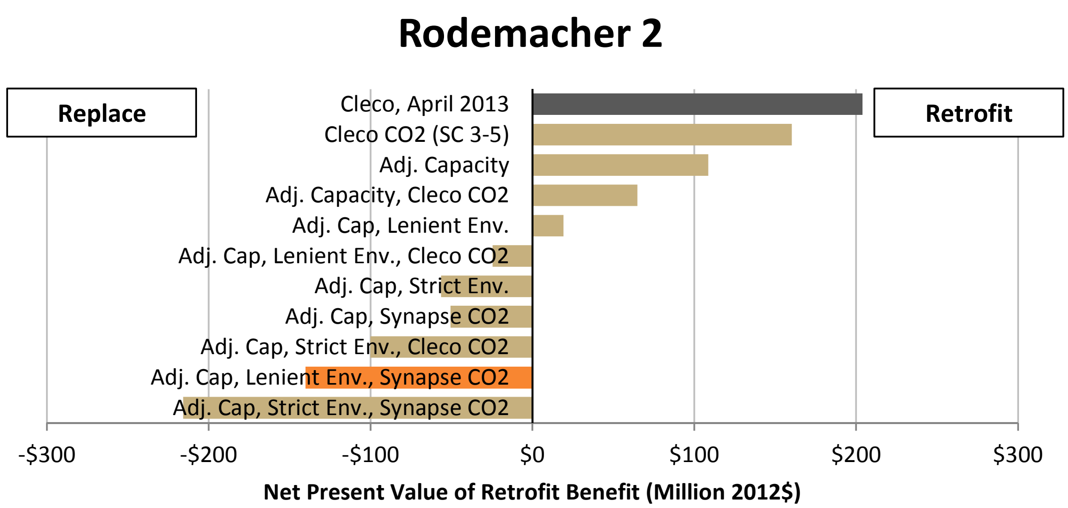

Figure 1. Net present value of retrofit benefit at RPS2 in Cleco analysis (top bar) and with adjustments for capacity balance, carbon pricing, and environmental regulations. Synapse base case in orange.

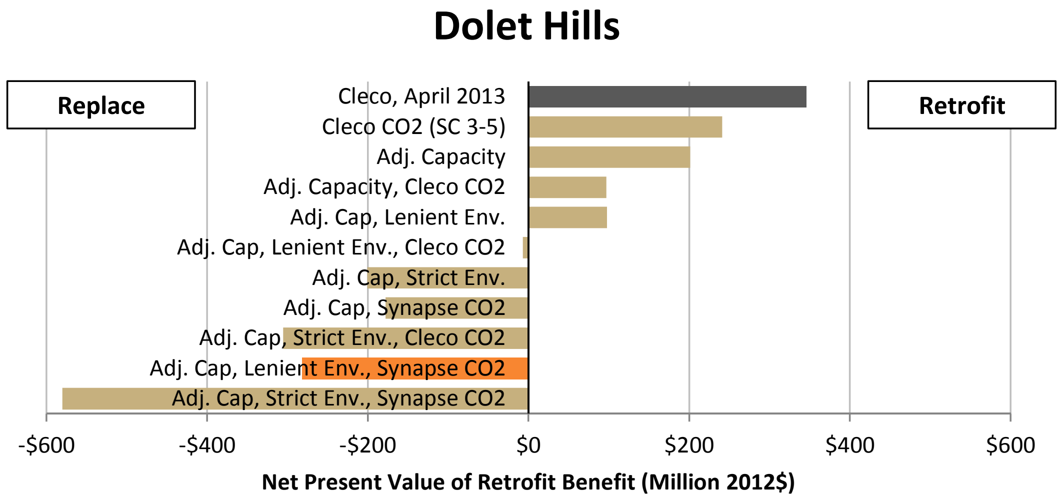

Figure 2. Net present value of retrofit benefit at Dolet Hills in Cleco analysis (top bar) and with adjustments for capacity balance, carbon pricing, and environmental regulations. Synapse base case in orange.

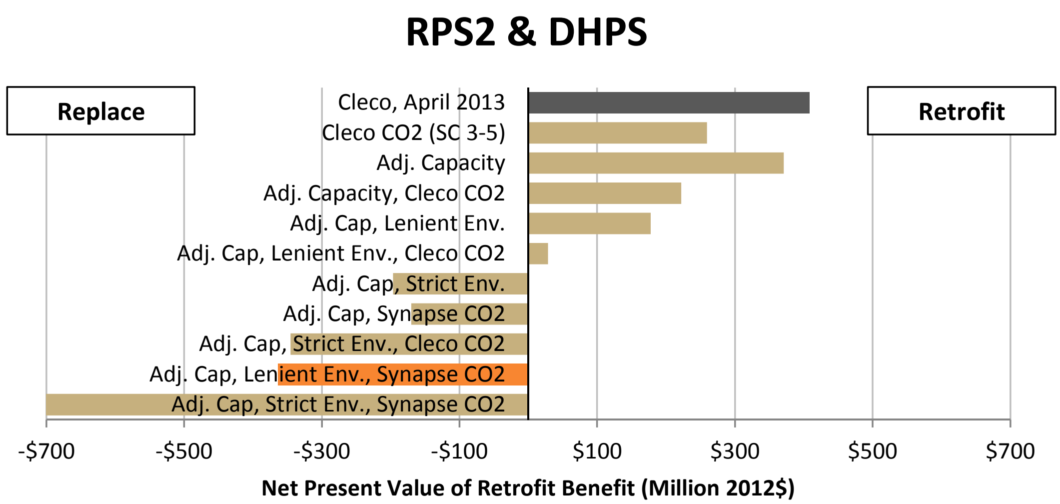

Figure 3. Net present value of retrofit benefit at both RPS2 and DHPS in Cleco analysis (top bar) and with adjustments for capacity balance, carbon pricing, and environmental regulations. Synapse base case in orange.

Q What are your recommendations to this Commission?

A Based on my analysis of the economic viability of RPS2 and DHPS, and the level of analysis and justification provided by the Company in this case, I recommend that the Commission deny the Company authorization to install the MATS controls at RPS2 and DHPS, and deny the Company's petition to recover the costs associated with the RPS2 and DHPS MATS control equipment.

I think that it is highly likely that the MATS controls being installed today at these two units will be rendered redundant and obsolete within a few years, creating stranded costs well within the 40-year book life of these retrofits.[13] Further, the balance of environmental costs still facing these two units renders them non-economic on a forward-going basis; the Company simply should not install capital-intensive retrofits with the expectation of an extended recovery.

Outside of the MATS rule, the Company has not analyzed or reviewed future compliance obligations for RPS2 or DHPS.[14] By allowing the current slate of retrofits to proceed, the Company is engaging in a piecemeal approach to regulation, asking ratepayers to fund these retrofits without disclosing the plethora of capital and operating costs these units will incur in the next few years. Instead, the Company is asking for the authority to place a long-odds bet, with ratepayer monies, that federal regulations will not require additional controls at the Company's units.

2. Lack of Transparency in Company Model

Q Have you been able to trace the basis of the Company's analysis in the workpapers provided to you?

A Generally, yes. I have identified the workpapers and formulations used by the Company in Mr. Sharp's final evaluation, but I have been unable to trace the basis of some key assumptions.

[13] Exhibit JRC-2, pages 2 & 3.
[14] See Response to Sierra Club DR 1-41 through 1-45 (attached as Exhibit JIF-7), with the exception of a placeholder emissions cost for the now vacated Cross State Air Pollution Rule (CSAPR), see Response to Sierra Club DR 1-47 (attached as Exhibit JIF-8).

First, the Company only provided workpapers supporting the supplemental testimony of Mr. Sharp, rather than his original analysis.[15]

Second, the Company was unable to provide either inputs or outputs of the proprietary production cost model used for this analysis in an accessible form,[16] producing only the reports used by Mr. Sharp in his analysis, and hindering Commission and intervener opportunities to audit and review the Company's assumptions.

Q Why is it important to evaluate the original evaluation performed by Mr. Sharp?

The analysis presented by Mr. Sharp in his direct testimony represents the information known and used for evaluation by the Company at the time the decision was made to proceed with the MATS compliance plans presented here. According to Exhibit GAC-5, Cleco issued an "Authorization to Construct" to contractors (i.e., signed a commitment to pay for the retrofits) in August 2012. This was prior to the submission of direct testimony, and eight months prior to the submission of Mr. Sharp's corrections.

Q Why would you have needed to evaluate the inputs used in the Company's dispatch model?

A There are fundamental elements of a dispatch model that are highly influential in the behavior and outcome of the model, that were not provided directly, including the assumed market price of electricity, import and export constraints, and forced

[15] Data Request SC 2-1: Please produce all workpapers, spreadsheets, and documents supporting the prefiled direct and supplemental testimonies of Richard Sharp. Produce files in machine readable, electronic, digital format, as used by the Company, with protections removed. Please specify if any files have been altered after the filing date of testimony, and detail any alterations. Company responded with a series of files that ultimately show the output from Mr. Sharp's supplemental testimony, rather than direct testimony. Attached as Exhibit JIF-9.

[16] Data Request SC 2-2(f): Produce in machine-readable, electronic, digital format, as used by the Company, with protections removed, all input files used in production cost and/or optimization modeling for this case. Data Request SC 2-2(h): To the extent that such input files, as used by the Company, cannot be produced in a commonly accessible format (i.e., text file, spreadsheet, or Access file), produce input files in a commonly accessible format. Company responded to (f) with a large file in a proprietary data format that cannot be read without access to the Company's proprietary model. Company responded to (h) "N/A". Attached as Exhibit JIF-10.

outage rates. I could derive some factors, such as fuel prices, heat rates, and variable O&M expenses from the provided outputs, but they may not represent the exact assumptions used by the Company. Not having access to the inputs makes it quite difficult to compare the Company's assertions in testimony against the actual model.

Q Have other utilities provided inputs into proprietary models for you previously?

A Yes. It is actually quite common for utilities to provide detailed model inputs in a standard data format, and other Companies have provided this data without comment in other cases.

Q Do you have other concerns with the Company's analysis?

A Yes, quite a few, and as I stated earlier, most of these concerns result in a biased outcome against the selection of an alternative to the retrofits. Overall, it is difficult to justify the coal retrofits on the basis of the analysis provided by the Company, and is difficult to see how these investments qualify as a prudent use of ratepayer monies. I'll detail each of my concerns in turn, and quantify those that can be monetized.

3. OVER-PROCUREMENT OF NGCC CAPACITY

Q Earlier, you noted that in the Company's analysis, retiring both units has a relatively favorable outcome to retiring either of the two units individually. Why is this this case?

The reason for this peculiar outcome lies in the fact that the Company didn't size replacement units commensurate with its ownership share of RPS2 and DHPS, examining NGCC units that were 73% and 52% larger, respectively, than the units being replaced. Thus, replacing 144 MW of capacity at RPS2 with a 250 MW NGCC unit assumes that the Company procures 106 MW of gas capacity that they do not require in the retrofit case, effectively requiring the Company to acquire an NGCC [redacted] million in excess of its capacity shortfall.[17] Similarly, replacing 318 MW of capacity at DHPS with a 480 MW NGCC unit requires the Company to acquire [redacted] million in excess of the shortfall due to the retirements.[18] In contrast, in the scenario where both units are retired, the Company replaces 462 MW of solid fuel generation with the same 480 MW NGCC, but due to the smaller discrepancy between the capacity gap and the replacement unit, the retrofits are only favored by about [redacted] million, rather than over [redacted]' million, as in the other two scenarios.

The assumption by the Company that they would have to incur excess capital costs to build an oversized NGCC biases the analysis significantly against the selection of replacement capacity.

I'll note that the Company does ascribe a market value to both capacity excess and shortfalls; the analysis presumes they can acquire some capacity on the market, or sell excess capacity on the market.[19] Therefore, in its analysis, the excess NGCC capacity does have a market value. However, this capacity value, even at the market prices assumed by the Company, does not cover the full revenue requirements of the excess capacity. For example, if the Company builds 250 MW instead of 144 MW in replacing RPS2, they assume a capacity market benefit of [redacted].[20] However, the excess revenue requirement to build a larger NGCC is [redacted] NPV, therefore leaving the NGCC replacement scenario disadvantaged by [redacted] Similarly, the 480 MW NGCC replacement for DHPS is disadvantaged by $[redacted] after taking into account capacity benefits.

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[17] 250 MW NGCC – 144 MW at RPS2 = 106 MW of excess capacity at a cost of [redacted]

[18] 480 MW NGCC – 318 MW at RPS2 = 162 MW of excess capacity [redacted]

[19] It is the case that under the MISO construct, the Company can acquire part of its capacity requirement through the MISO Resource Adequacy Voluntary Capacity Auction.

[20] This benefit is comprised of both capacity market payments to the Company in early years when the Cleco is over its reserve margin, and diminished capacity payments from the Company in later years when Cleco is below its reserve margin.

Q Why did the Company choose to analyze units sized differently than its shortfall?

A The Company explained that it selected the replacement sizes for these units because they were only aware of 250 MW 1x1 CCGTs and 480 MW 2x1 CCGTs.[21]

Q Was the Company restricted to the review of only 250 and 480 MW units?

A No. PacifCorp, in its 2013 IRP, reviewed more than a dozen CCGT configurations at various capacities, ranging from 255 MW 1x1 at the smallest to a 715 MW 2x1 at the largest. More importantly, the Company has the opportunity to share a larger resource with either another utility or a merchant generator, tuning its requirements to more exacting specifications. In my experience, these types of replacement cases are characterized by a comparison against an equally sized replacement unit, or share of a unit, to eliminate any questions regarding the comparison of completely different requirements.

Q Are you able to quantify the impact of the oversized replacement units in the Company's analysis?

A Yes, in rough terms. I created alternate versions of the Company's economic evaluation (as supplied in SC 2-1) in which I tested the economic viability the retrofit when compared against the exact same amount of replacement capacity. I'll refer to these versions of the Company's analysis as the "adjustment for capacity balance." To perform this analysis, I modified five components of the Company's evaluation to scale the replacement NGCC units from the default 250 MW and 460 MW to the Company's ownership share of RPS2 and DHPS (144 MW and 318 MW, respectively). I also created an alternate analysis for the combined retirement analysis, reviewing a 462 MW unit. For my modifications, I re-scaled the capacity available for offsetting MISO capacity purchases,[22] the capital cost of the replacement NGCCs,[23] the fixed O&M cost of the NGCCs,[24]

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[21] See Company response to SC 1-80, Attached as Exhibit JIF-35.
[22] Modification of xxMATS Upgrades Impact Summary.xlsx, tabs $3 / $5.
[23] Modification of RR Model – 250 / 460 MW CCGT.xlsx, tab "AFUDC – Basis"

the periodic maintenance costs of the NGCC,[25] and the terminal values of the NGCC replacement units in 2034.[26]

Since I did not have access to the Company's assumed market prices or dispatch model, I was unable to modify the energy production and fuel/variable O&M consumption of the NGCC units. Effectively then, incremental energy requirements are met at the variable cost of an NGCC. When the Company evaluated an oversized NGCC, a portion of the Company's energy comes from that NGCC at the variable cost of production. Since I was unable to alter the production cost, my modifications still require that the Company obtain that same fraction of energy at the variable cost of production of an NGCC. I believe that this assumption (compelled by a lack of data) is reasonable.

Q **What is the outcome of your re-analysis with correctly sized units?**

A The results are quite dramatic. Simply balancing the capacity that the Company procures to replace the solid-fuel units almost completely undoes the Company's baseline analysis, and cuts away a significant fraction of the benefit even at higher gas prices (see Table 2, below).

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[24] Modification of RR Model – 250 / 460 MW CCGT.xlsx, tab "Inputs", cell D55.
[25] Modification of CCGT Maintenance Schedule - $3 Gas – etc…, tab for NGCC unit, cells E6:E8
[26] Modification of xxMATS Upgrades Impact Summary.xlsx, tab "Terminal Values"

Table 2. Synapse Re-analysis: PVRR of retrofit and retirement scenarios in 2012 and 2013 analyses with balanced NGCC capacity (millions 2015$).[27]

	Capacity Correction: $3 Gas		
	RPS2	**DHPS**	**RPS2 & DHPS**
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	**$14**	**($22)**	**$24**
	Capacity Correction: $5 Gas		
	RPS2	**DHPS**	**RPS2 & DHPS**
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	**$138**	**$272**	**$479**

For example, the benefit of retrofitting RPS2 declines by a full order of magnitude, an almost 88% drop from Mr. Sharp's supplemental analysis provided in April 2013 ($146 to $14 million). The benefit of retrofitting DHPS disappears completely as the $127 million benefit becomes a $22 million liability, and the benefit of retrofitting both units also falls by 40%, to $24 million. The adjustment is less pronounced at the high gas price assumption, because much of the adjustment is a fixed cost change. However, the benefit of retrofitting RPS2 and DHPS is cut by 35% and 41%, respectively.

Q Why is it appropriate to review the retrofits against a similar capacity option?

A The Company is looking to replace specific energy and capacity assets, and as such the correct cost/benefit analysis should assume no particular additional benefit (or liability) for building more (or less) than required. The Company may require additional capacity or energy at a future date, or even today – or may have excess capacity or energy, but the value of the existing assets should be judged against a similar procurement of capacity and energy. The Company should not compel ratepayers to pick up several hundred million dollars' worth of excess

[27] Direct testimony of Richard Sharp, Exhibit RLS-1; Supplemental direct testimony of Richard Sharp, Exhibit RLS-1-A.

capital expense for the simple convenience of using a standard-sized NGCC unit in this analysis. The standard analysis of this form assumes that the exact amount of replacement capacity is procured, and excess is either co-owned with other utilities, or procured under a merchant wing (i.e., not by ratepayers). If Cleco desires an excessively large unit, the Company's shareholders are welcome to pay for the excess capacity and receive the benefits, if any, of those sales.

4. <u>FAILURE TO EVALUATE ALTERNATIVE OPTIONS OR OPTIMAL SOLUTION</u>

Q Did Cleco review any options as an alternative to the retrofits aside from a new replacement NGCC?

A No, not in any of its filed testimony or the modeling supporting the filed testimony. It is not at all clear that a new NGCC is the least cost replacement for the Company's capacity and energy requirements. The Company's failure to seek an optimal replacement alternative to the retrofit coal units is imprudent.

Q Did the Company consider any other alternatives aside from the new NGCC?

A Yes, but the Company did not model these alternatives in the economic evaluation. In response to discovery, the Company states that "Cleco Power considered, but did not evaluate fuel switching at DHPS or Brame Energy Center because it would unduly reduce Cleco Power's current fuel diversity."[28] When asked for further detail regarding this "consideration," the Company responded that it "did not model the replacement of its base load solid fuel fired generation and capacity with natural gas fired steam turbine generation."[29] However, reviewing the documentation supporting this response, the Company clearly had considered [redacted]

[28] Response to SC 1-78. Attached as Exhibit JIF-33.
[29] Response to SC 3-59. Attached as Exhibit JIF-13.

[redacted][30] [redacted]

A conversion to natural gas could compare quite favorably against the two options considered by the Company (retrofit, or replacement with a new NGCC). The capital costs are low, and thus the Company would maintain capacity at a fairly low incremental cost. Gas-fired steam units generally operate at a relatively low capacity factor, and thus the Company would presumably look to the market, energy-only power purchase agreements (PPAs), or renewable energy contracts for energy. However, this analysis was not conducted by the Company.

Q Have other utilities found that conversion to gas-firing is an economic alternative?

A Yes. For example, PacifiCorp initially applied for pre-approval to construct an SCR system at the Naughton 3 unit in Kemmerer, Wyoming, but after intervener critique and subsequent detailed analysis, withdrew the application. According to the Wyoming Public Service Commission (WPSC) order:

> On April 9, 2012, the Company filed, in its own words, "rebuttal testimony and updated data, based on the analysis undertaken in response to testimony filed by interveners, showed that the planned environmental upgrades to the Naughton Unit 3 generating facility are no longer cost-effective, and that the interests of the Company and its ratepayers would best be served by converting the Naughton Unit 3 generating facility to a natural gas peaking facility. The analysis shows that the conversion to natural gas is the risk adjusted, lowest cost compliance alternative when compared to the mandated environmental upgrade projects using updated model input assumptions, updated market information and advancements in modeling methodology." On May 11, 2012, RMP followed up with a *Motion* to withdraw the application on the grounds that it

[30] Response to SC 3-59, Attachment B [redacted] Attached as Exhibit JIF-13.

> decided to not pursue a CPCN for Naughton Unit 3 environmental upgrade.[31] [Emphasis added]

Conversion to natural gas for existing facilities can be a low cost mechanism of meeting environmental obligations, and in the case of Cleco [redacted]

Q How does the Company support the statement that "fuel switching…would unduly reduce Cleco Power's current fuel diversity?"

A They do not support it at all. Sierra Club requested "the method by which Cleco quantified or evaluated the degree to which fuel-switching would 'unduly reduce Cleco Power's current fuel diversity,'" and received no answer or document that addressed this question either directly or indirectly.[32]

I would expect that to demonstrate a detrimental impact of reduced fuel diversity, the Company would have to show quantitatively that its system would be impaired with lower fuel diversity, and that the maintenance of its current solid fuel units decisively reduces risk and/or costs. The Company has not demonstrated any such analysis or review; simply stating that fuel diversity is of inherent value is insufficient. In addition, diversity of resources can be accomplished through other hedging mechanisms, such as investment in renewable energy, demand-side management (DSM), and fixed cost PPAs.

Q What options, aside from a new NGCC, should the Company have evaluated?

A The Company should have reviewed opportunities to obtain low cost PPAs, renewable energy options including wind, solar, and residual biomass, DSM options including energy efficiency and peak demand reduction, transmission options, peak resources (such as simple cycle gas units), market-based options

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[31] Wyoming Public Service Commission. Order Granting Motion to Withdraw Application, Docket 20000-400-EA-11 (Record 12953). July 19, 2012. Available online at http://psc.state.wy.us/htdocs/orders/20000-400-20869.htm. Attached as Exhibit JIF-34.

[32] See question and response to SC 3-59(d). Attached as Exhibit JIF-13.

(i.e. spot market purchases), or purchasing excess generation facilities, if available.

The Company should have reviewed all of these resources in the context of an optimization or capacity expansion model.

Q What is an optimization or capacity expansion model?

A An optimization model selects a portfolio of resources that meet customer requirements at the least cost. Typically, these models are populated with a large number of supply-side (and sometimes demand-side) resources, and allowed to choose the least cost mix of resources. The Company can rigorously test the mix (or mixes) selected by the optimization model against different market conditions.

The Company did not use an optimization model, instead pre-selecting a single alternative, the new NGCC. It is quite possible, and even likely, that the Company did not review the least cost alternative to the retrofit of the existing units, thereby depriving the Commission and Interveners of a fair analysis of the options available to Cleco's ratepayers.

5. FAILURE TO EVALUATE MISO MARKET PURCHASES AND SALES.

Q How does the Company's model meet future demand requirements?

A The production cost model used by the Company appears to increase the capacity factor of gas units in the Company's portfolio from 2015 through 2034. For example, in the base scenario low and high gas prices, the [redacted] In contrast, the coal units maintain flat capacity factors over that period. In the replacement scenarios, the story is the same, [redacted] making up much of the energy requirement.

I think this is an unlikely scenario for how the utility would actually respond to increased demand, unless these [redacted] units become far more economic relative to the market over time.[33]

Q **How does the Company account for the availability of market purchases or sales?**

A In this model, the Company has not accounted for significant market trades – or if such trades are available, it is not clear that they are utilized. The Company shows energy sources called "[redacted]" which I assume are different energy products. The fact that these are labeled "[redacted]" is non-intuitive, as I assume they would be purchases from other entities, including <u>from</u> [redacted] However, these sources account for less than 6% of the Company's energy balance, and it does not appear that there are sales in the model (i.e., no negative energy flows).

Q **Does the Company have access to a retail energy market?**

A Yes. As of June 26, 2013, Cleco received approval from this Commission to join the Midcontinent Independent System Operator (MISO) energy market as full participants. As such, it has access to retail services in MISO, including the day ahead and real-time energy markets, capacity markets, and markets for ancillary services. I believe that the Company touted these benefits in Louisiana PSC Docket U-32631. As the Commission noted in its order approving Entergy's application to join MISO, "[t]he larger market, and MISO's market design will likely provide buyers and sellers with more rather than fewer options."[34]

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[33] It is notable that the coal units do not change their output over the analysis period – maintaining flat capacity factors from 2015-2034. The coal units appear to have ample headroom and a lower variable cost in the Company's model – therefore the coal units should be increasing output faster than the gas units.
[34] LPSC Docket No. U-32148, In Re: Joint Application Regarding Transfer of Functional Control of Certain Transmission Assets to the [MISO], Order issued June 28, 2012, at p. 13.

Q **Do the model results that you were provided indicate any interaction with the MISO market?**

A No, and as I described above, the results do not conform to my expectations of how Cleco's units would operate if they were centrally dispatched by MISO.

6. <u>FAILURE TO EVALUATE BASE-CASE FORECAST GAS PRICES</u>

Q **What roles does the price of natural gas play in this type of analysis?**

A The Company has set up its economic evaluation as a choice between its existing coal units and a replacement natural gas unit. The forecast price of natural gas therefore influences the outcome of the Company's analysis.

Q **What has the Company assumed for the price of natural gas in this analysis?**

A In the initial September 2012 testimony, the Company assumed a natural gas price held at a constant (2012$) value of $3/MMbtu.[35] In supplemental testimony, filed in April 2013, Mr. Sharp included an additional analysis with a constant (2012$) value of $5/MMbtu.[36]

Q **Do either of the Company's gas prices represent a reasonable baseline trajectory for gas prices?**

A No. While there are currently a wide range of estimates for the future of natural gas prices, I am not aware of any forecast that maintains a $3/MMBtu price through the end of the 20 year analysis period in 2034. I am also not aware of any reasonable forecast that assumes prices as high as $5/MMBtu in 2015. So while the $3/MMBtu price is likely too low, the $5/MMBtu price as of 2015 is not reasonable either.

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[35] Mr. Sharp represents the gas price as "$3.23 to $5.16 per MMBtu, reflecting an average growth rate of 2.5% annually" (Direct Testimony of Mr. Sharp, page 10, lines 5-7). However, the entire analysis is conducted in nominal terms, with an underlying 2.5% inflation rate. Therefore, in real terms, the gas price is held constant at $3/MMBtu.

[36] Mr. Sharp represents the higher cost scenario as "Cleco Power also included a higher natural gas cost curve scenario, which reflects a natural gas cost for 2015 of $5.38 per MMBtu, increasing by 2.5% annually thereafter." Again, in constant terms, this is a flat $5/MMBtu analysis.

Mr. Sharp compares the two bookend gas prices against 2013 Annual Energy Outlook (AEO) reference case natural gas price from the U.S. Energy Information Administration (EIA), but does not provide a metric to evaluate the highly disparate results from the Company's low gas price and high gas price analyses.

Q How does the AEO 2013 reference case natural gas price compare against the two bookends provided by the Company?

A In his supplemental direct testimony, Mr. Sharp shows a graphic (Chart 1) suggesting that the AEO 2013 reference case grades gradually from the lower bound gas price to the upper bound gas price used by the Company. While generally the trend is correct, Mr. Sharp has inadvertently mixed nominal dollars between the Company's assumptions and that of EIA. The Company uses a 2.5% inflation rate assumption, while EIA uses a 1.6%-1.7% inflation rate for gas prices. Comparing gas prices in constant dollars, the EIA's forecast actually exceeds the $5/MMBtu mark in 2026, not 2021, as Mr. Sharp concludes.

Q Have you adjusted the Company's results to account for a reasonable baseline gas price forecast?

A I have. I used components of the Company's low and high gas price analysis to develop a hybridized AEO 2013 gas price equivalent.

The Company assumes the same resource mix at high and low gas prices, and thus the only difference between the low and high gas price scenarios are production costs based on gas prices. To adjust the Company's analysis, I took an annual mix of the high and low gas price production costs at a ratio that reflects the gas price forecast in AEO 2013. For example, in 2015, the AEO gas price is about $3.2/MMBtu (2012$), or about 9% of the Company's high gas price outcome and 81% of the Company's low gas price outcome. In 2018, the AEO 2013 gas price is $4.0/MMBtu, or a 50/50 split between the Company's low and high gas price outcome. This trend is carried through the end of the analysis.

Overall, on a net present value basis, the hybridized AEO 2013 production cost represents about 77% of the high gas price and 23% of the low gas price scenarios proposed by the Company. The resulting AEO 2013 gas price is higher than the initial $3/MMBtu analysis submitted by Mr. Sharp in September 2012.

For the remainder of my testimony, I present the final values as AEO 2013 gas price equivalents, being mixed outcomes of the Company's low and high gas price scenarios.

7. <u>FAILURE TO EVALUATE A COST FOR THE MITIGATION OF CARBON DIOXIDE POLLUTION</u>

Q Did the Company consider the potential for costs associated with carbon dioxide emissions in its economic evaluation?

A No. In filed testimony, the Company has completely disregarded the risk of a price on carbon dioxide (CO_2) emissions anytime in a future relevant to these units.[37] Disconcertingly, the Company did review a carbon price impact in its own internal study, but did not release the results of this CO_2 analysis to this Commission.[38] [redacted][39]

Q Is it reasonable to assume that emissions of CO_2 will remain cost and risk free?

A No. A baseline forecast of no CO_2 price is an unreasonable assumption. The state of climate science continues to strongly indicate that CO_2 contributes to detrimental global climate change. As a scientist who studied the impacts of climate change on people, the environment, and infrastructure – focusing in

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[37] See Response to Sierra Club SC 1-82. Attached as Exhibit JIF-12.
[38] See Response to Sierra Club 3-5. "Please see the attached compact disk, which includes the addition of a carbon tax without an allocation of emission allowances." Attached as Exhibit JIF-11.
[39] SC 3-59.1 Attachment B. Attached as Exhibit JIF-13.

particular on the Gulf Coast – it is my opinion that any hesitancy to regulate carbon emissions will not stand long in the face of increasingly dramatic evidence. I think that it is quite likely either the U.S. Environmental Protection Agency (EPA), or eventually Congress, will regulate CO_2 emissions in the next twenty years.

Q Do other Commissions expect utilities to examine CO_2 prices in resource planning?

A Yes. For example, the Arkansas Public Service Commission recently ordered utilities to assign a non-zero avoided regulatory cost for carbon emissions as part of energy efficiency cost-effectiveness analysis.[40] The Indiana Utility Regulatory Commission, citing the risk of carbon regulation to the economic viability of a coal unit, determined that the costs of environmental compliance would not be recoverable by a utility should carbon regulation render the unit non-economic.[41]

Q Is there any change in the risk of impending carbon regulation since the Company submitted this application?

A Yes. The Company submitted the initial application in September 2012, and filed supplemental testimony in April 2013. On June 25, 2013, the President announced a series of initiatives to start regulating carbon emissions from new and existing fossil fuel fired electricity generators. Earlier, in May 2013, the Administration also released a new series of estimates for the "social cost of carbon" (SCC), a monetized estimate of the damage caused to society by global climate change.[42] Together, these two announcements signal a strong intent by the current Administration to seriously reduce carbon emissions from new and existing sources.

[40] See Arkansas PSC, Docket 13-002-U, In the Matter of the Continuation, Expansion, and Enhancement of Public Utility Energy Efficiency Programs in Arkansas, Order No. 1, at p.19.
[41] Indiana Utility Regulatory Commission. August 14, 2013. Verified Petition of IPL for Approval of Clean Energy Projects…etc.. Cause 44242. Final Order. Page 36. http://www.in.gov/iurc/files/44242order_081413.pdf
[42] See Exhibit JIF-15.

Clearly the Company had the ability to recognize this risk, as demonstrated in the construction of the hidden CO_2 analysis, but did not incorporate the results of the CO_2 analysis for consideration before this Commission.

Q What was entailed in the President's June 2013 announcement?

A In conjunction with a public announcement, the White House released a memorandum containing several directives.[43] Referring to the EPA, the memo stated (in part):

> Section 1. (b) Carbon Pollution Regulation for Modified, Reconstructed, and Existing Power Plants. To ensure continued progress in reducing harmful carbon pollution, I direct you to use your authority under sections 111(b) and 111(d) of the Clean Air Act to issue standards, regulations, or guidelines, as appropriate, that address carbon pollution from modified, reconstructed, and existing power plants and build on State efforts to move toward a cleaner power sector. In addition, I request that you:
>
> (i) issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2014;
>
> (ii) issue final standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2015; and
>
> (iii) include in the guidelines addressing existing power plants requirement that States submit to EPA the implementation plans required under section 111(d) of the Clean Air Act and its implementing regulations by no later than June 30, 2016.

Q Is it clear what would happen under a Section 111(d) construct to regulate carbon dioxide emissions from existing power plants?

A Not yet. Under Section 111(b) of the Clean Air Act, EPA is required to propose new source performance standards (NSPS) for existing sources of pollution once those standards have been set for new sources. On September 20, 2013, EPA

[43] See Exhibit JIF-16

released a draft NSPS for greenhouse gases (i.e., CO_2) at new sources. The draft NSPS would require all new fossil generation to emit CO_2 at a level no greater than that of an efficient natural gas plant; new coal plants would effectively have to use carbon capture and sequestration to pass this threshold.[44] EPA also announced that it will issue a proposal for CO_2 at existing sources under Section 111(d) by mid-2014.[45] At this point, I do not believe that there is any resolution on exactly what standards EPA will propose for existing units.

Unit-specific emission rates standards—such as the proposed CO_2 NSPS for new sources—are one of several plausible options. Unit-specific standards could categorize power plants by fuel and technology type, each with its own maximum emission rate.[46] Other regulatory design options for existing units covered under Section 111(d) include maintaining a state-wide average maximum emission rate, or market-based (e.g. cap-and-trade) approaches.

On August 5, 2013, ICF International, a primary consultant for EPA responsible for modeling the impact of environmental regulations, released a whitepaper exploring options available to the EPA.[47] This paper discusses a number of non-flexible options, such as requiring specific heat-rate improvements or certain retirement deadlines, as well as flexible options, such as standard based cap-and-trade mechanisms.

While it is unclear which mechanism will be proposed as of yet, it is increasingly certain that any proposal will effectively impose either a real or effective cost on carbon emissions. In the current regulatory environment, it is inappropriate to still consider a zero cost as a reasonable baseline, much less the only option examined.

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[44] See EPA, 2013. EPA Proposes Carbon Pollution Standards for New Power Plants/Agency takes important step to reduce carbon pollution from power plants as part of President Obama's Climate Action Plan. http://yosemite.epa.gov/opa/admpress.nsf/0/da9640577ceacd9f85257beb006cb2b6!OpenDocument

[45] *Id.*

[46] Units that are out of-compliance could undertake upgrades to improve efficiency, although these kinds of upgrades are expensive and can only achieve small, one-time changes to emission rates.

[47] Attached as Exhibit JIF-17

Q Do you have an opinion regarding a reasonable carbon price forecast for use in cases such as this?

A Yes. Synapse tracks the state of CO_2 policy and regulation, and utility views of regulatory initiatives, which we make available to the public. Synapse has recently released an updated carbon price discussion paper and forecast, attached as Exhibit JIF-19. We break our forecast into a bounded region of likely prices, all starting in 2020. The mid-case starts at $15/ton in 2020 and rises to $60/ton by 2040 (2012$); this case represents our best estimate of a reasonable base case. The attached discussion paper details the background and assumptions underlying the forecast.

Q You stated that the Company performed its own internal hidden CO_2 analysis of carbon prices on the results of this analysis. What did they do?

A In the hidden CO_2 analysis, the Company performed an internal evaluation of the impact of a CO_2 price, but did not disclose or support its results before this Commission.[48] The Company examined a CO_2 price starting at [redacted] But the forecast also doesn't comport with assumptions made by other utilities in contemporary planning documents. Of 2012/2013 forecasts that Synapse has compiled from 24 independent utilities,[49] not a single one [redacted] and only five [redacted] the Company's forecast is incorporated into its hidden analysis results in an illogical manner – the CO_2 price was not included in Cleco's production cost model and does not impact the dispatch of the Company's units. In other words, even with a price on carbon emissions, the Company assumes that its units would dispatch exactly as if there

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[48] See Response to Sierra Club 3-5. Attached as Exhibit JIF-11.

[49] See Synapse 2013 CO_2 Price Forecast, page 18

were no emissions price. I am not aware of another utility that has made the assumption that a carbon price would not impact the operations of its units.[50]

Q Should a price on CO_2 impact dispatch decisions?

A Yes, it is a variable cost realized by a generator, and thus should be factored into its dispatch merit. In MISO, the cost of emissions would certainly impact the Company's bid price into the energy market. Whether a generator is paying for CO_2 through a real or an effective price on emissions,[51] there is an opportunity cost to emitting a controlled pollutant.

The CO_2 price assumed by the Company in the hidden CO_2 analysis actually inverts the merit order of its units in both the low- and high-gas price scenarios. If the Company had incorporated the CO_2 price into the variable operating cost of its units, its gas units (i.e., Acadia) would dispatch at a lower cost than the coal units at both high and low gas prices. The practical implication is that the capacity factor of the coal units would shrink, and the Company's opportunities to earn back fixed costs (such as these capital retrofits) would diminish significantly.

Q What was the outcome of the Company's hidden CO_2 analysis?

A Bearing in mind that the results are skewed because the Company did not incorporate emissions costs into the variable cost of operation, the Company finds that the net benefit of retrofitting RPS2 and DHPS [redacted] Table 3, below, shows the AEO 2013 gas price equivalent outcome of the Company's analysis with and without the Cleco CO_2 price adder.

[50] It is notable that even in the Company's base case runs (SC 2-1 and 2-3), the Company models a NOx emissions price as an after-effect. The NOx price is also not incorporated into dispatch which, like the modeling of the CO_2 price in SC 3-5, is incorrect.

[51] Effective prices on emissions are discussed in the Synapse 2013 Carbon Price Forecast paper attached as Exhibit JIF-19.

A

Table 3. Cleco Analyses with AEO 2013 gas price, both with and without Cleco CO_2 price: PVRR of retrofit and retirement scenarios (millions 2015$).

Cleco Analysis without CO_2 price: AEO 2013 Gas

	RPS2	DHPS	RPS2 & DHPS
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	**$204**	**$346**	**$409**

Cleco Analysis with Cleco CO_2: AEO 2013 Gas

	RPS2	DHPS	RPS2 & DHPS
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	[redacted]	[redacted]	[redacted]

When I add the Cleco CO_2 price to the adjustment for appropriate capacity balance, as discussed earlier in Section 3 (page 16, above), the results become far less robust than presented by the Company (see Table 4). This version of the Company's hidden CO_2 analysis shows the benefit of retrofit in a world in which a very low price is imposed on carbon a [redacted] and the EPA fails to promulgate any further environmental regulations in the next two decades. Despite these caveats, the outcome is far less decisive than presented in the Company's original and supplemental analyses.

Table 4. Cleco Analyses with AEO 2013 gas price, Cleco CO_2 price and capacity balance adjustment: PVRR of retrofit and retirement scenarios (millions 2015$).

Capacity Correction with Cleco CO_2: AEO 2013 Gas

	RPS2	DHPS	RPS2 & DHPS
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	[redacted]	[redacted]	[redacted]

Q Have you conducted an analysis using a different CO_2 price?

A Yes, although by design of the Company's analysis and the lack of input data provided in discovery, I was not able to impose a CO_2 price on the dispatch of the Company's units against its anticipated MISO market price of energy. To do so reasonably would require an hourly estimate of the energy market hub prices, and it is unclear if the Company's production cost model represents the MISO market at all or if the Company's model operates at an hourly timescale.

I substituted the Synapse mid-CO_2 price forecast for the Company's trajectory in the analysis provided in SC 3-5.

Using the Synapse mid-case CO_2 price forecast and the AEO 2013 gas price forecast, the original net benefit of retrofitting the Company's coal units becomes a distinct liability (see **Table 5**).

Table 5. Cleco Analyses with AEO 2013 gas price, Synapse CO_2 price and capacity balance adjustment: PVRR of retrofit and retirement scenarios (millions 2015$).

Capacity Correction w/ Synapse CO_2: AEO 2013 Gas			
	RPS2	**DHPS**	**RPS2 & DHPS**
Retrofit	[redacted]	[redacted]	[redacted]
Retire	[redacted]	[redacted]	[redacted]
Benefit of retrofit	**($51)**	**($178)**	**($170)**

It is notable that a slight shift in assumptions results in a fairly large degradation in the Company's economic evaluation – in this case, shaving off nearly $500 million (2015$) in net benefit of the joint coal plant retrofit projects.[52]

[52] From +$408 million using the EIA 2013 gas price forecast on the Company's April 2013 analysis (see Table 3) to -$170 million adjusting for a balanced capacity replacement and a reasonable CO_2 price trajectory.

8. <u>FAILURE TO EVALUATE IMPENDING AND PROPOSED ENVIRONMENTAL REGULATIONS</u>

Q How are impending environmental regulations important to the case at hand?

A In addition to the regulation of greenhouse gases, a suite of final and proposed EPA regulations will require coal-burning power plants to install pollution controls.[53] The environmental retrofits at issue in this case are required for compliance with the MATS rule, one of multiple rules expected in the next few years. Just as the MATS rule imposes costs on the existing coal fleet, as made apparent by the retrofits at issue in this docket, other pending rules are also expected to have moderate to significant impacts on the costs of operating and owning coal units. While there is some uncertainty about what final standards EPA will promulgate, I am confident that EPA is about to issue a series of final regulations impacting coal-fired power plants.

In this forward-looking evaluation, Cleco has completely ignored the costs of compliance with proposed and pending environmental regulations, effectively assigning them a zero cost. In the current case, the Company does not even address, much less examine the risks of compliance obligations. The one non-MATS regulation that the Company does acknowledge—the 1-hour national ambient air quality standard (NAAQS) for SO_2—has critical implications in the Company's conclusions that retrofits are least cost.

Forthcoming environmental regulations will impose significant costs on Cleco's solid-fuel assets – DHPS, RPS2, and Madison 3. The controls contemplated in this docket are unlikely to mitigate most of these future costs. Ignoring these pending environmental regulations is simply imprudent: in doing so, the Company both vastly biases its economic analysis and effectively shifts the risk of environmental compliance costs onto the shoulders of its ratepayers.

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[53] Note: a proposed rule from the EPA is a draft version of the rule made available for public comment, and is usually a strong indicator that a final rule with similar provisions will follow.

Q **Is the Company aware of the environmental risks to which you refer?**

A Absolutely. It is clear that the Company has been tracking these rules. In the Company's 2011 10-K filing to the Securities and Exchange Commission (SEC), long pre-dating this application and the Company's finalized analysis, the Company detailed each of the rules to which I refer. The relevant portions of the 2011 10-K filing are attached as Exhibit JIF-20.

The SEC filing makes clear that the Company is aware not only of the presence of the rules, but the risks posed by these rules on its fleet. Similar language regarding the risks is also used in the Company's 2012 IRP.[54]

But the Company has not just ignored impending regulations for which it feels that there is insufficient information—the Company even disregarded direct warnings from [redacted]

[redacted][55] [redacted]

[54] Cleco 2012 IRP, p56-65.
[55] SC 3-59.1 Attachment B. Attached as JIF-13.

[redacted]

Q Which environmental regulations has the Company ignored in this analysis?

A Rules governing air quality, water quality, and coal combustion residual disposal are all expected to impose moderate to significant costs at existing coal-fired facilities. These rules include:

- finalized and emerging National Ambient Air Quality Standards (NAAQS),
- the re-issuance of the Cross State Air Pollution Rule (CSAPR),
- the proposed rules governing the disposal of Coal Combustion Residuals (CCR), and
- proposed Clean Water Act effluent limitation guidelines (ELG) for scrubber and ash handling wastewater at steam electric generating units.

I'll describe each of these rules in turn, and the expected impact of the rule on Cleco's generating stations.

Q Why did the Company ignore the impact of these rules on its evaluation?

A The Company has classified each of these rules as "speculative,"[56] and generally claims that it cannot know the implementation construct or timeframe, and thus providing proxy costs is not meaningful.[57]

Q Is ignoring the impact of these impending rules a valid mechanism for treating these regulations?

A Not at all. In fact, ignoring the economic impact of these impending rules ascribes a value to them of exactly zero dollars – i.e. the Company anticipates that there will be no cost at all to comply with any of these regulations. We can be quite certain that, unless EPA is prevented from implementing these rules, they will

[56] SC 1-41 through 1-44. Attached as JIF-7.

[57] For example, the response to SC-42, regarding the impact of the effluent limitation guidelines rule states that "Cleco Power objects on the basis that this question calls for speculation. This rule has not been proposed, and, therefore Cleco Power cannot respond."

likely impose costs on Cleco's coal fleet. By ignoring these rules, the Company decisively shifts the risk of future costs onto ratepayers.

Q Can the impact of these rules be known with absolute certainty?

A No. Until each rule is finalized, and until the state and EPA determine compliance mechanisms for electric generating units that violate these rules, the exact timing and impact of these rules is unknown. However, the Company should have evaluated proxy costs for reasonable bounding cases – lenient or strict implementation of the rules. Because the Company evaluated nothing at all, I will provide rough estimates for the capital and fixed O&M that might be incurred in the lenient and strict implementation of each of these rules. For each of the rules, I describe my assumptions under both bounding-end cases.

Ultimately, I assume that the strict case requires rigorous near-term compliance with all of these rules, and the lenient case requires longer-term compliance with most of the rules. My assumed capital costs for compliance, <u>none</u> of which were examined by Cleco, are as follows:

Table 6. Environmental compliance capital costs for RPS2 and DHPS under strict and lenient interpretations of environmental regulations.

		RPS2		DHPS	
Technology	**Applicable rule(s)**	**Strict**	**Lenient**	**Strict**	**Lenient**
Flue gas desulfurization (FGD)	SO_2 NAAQS CSAPR 2.0	[redacted] (2016)	[redacted] (2022)	$**341** (2016)	-
Selective Catalytic Reduction	$PM_{2.5}$ NAAQS Ozone NAAQS CSAPR 2.0	$**112** (2018)	$**112** (2021)	$**145** (2018)	$**145** (2021)
Water treatment	ELG	$**22** (2017)	$**3** (2022)	$**49** (2017)	$**6** (2022)
Coal waste mitigation	CCR	$**73** (2019)	$**73** (2021)	$**104** (2019)	$**91** (2021)
Cooling tower	316(b)	$**20** (2018)	-	-	-
Total		[redacted]	[redacted]	**$642**	**$301**

These costs are not engineering estimates; rather they serve as proxy costs in place of the zero costs contemplated by the utility.

Q Why is it not sufficient for the Company to determine the cost-effectiveness of the retrofits under the MATS rule only?

A Such an evaluation would be incomplete, as it ignores relevant planning information that the Company's management knows or should know, and could put ratepayers at risk for the costs of capital expenditures that, when considered as part of a whole, might not be cost-effective. Instead, the Company is pursuing a piecemeal approach— requesting cost recovery for a single upcoming cost (i.e., MATS) rather than considering the full costs to ratepayers of continuing to operate. Without factoring in the full-range of known and likely costs that ratepayers would have to bear, it is not possible to assert that the power plants in question produce low-cost generation. A piecemeal approach to evaluating capital upgrades to existing power plants ignores the 40-year-plus trend of steadily increasing and tightening environmental regulation in the United States. Not only is it reasonable for the Commission and the Company to assume additional regulation and additional regulatory costs will be imposed, but there is ample documentation and public discourse about the likely impact, targets, and costs of additional regulation. The Company's piecemeal approach to evaluating the upcoming costs of compliance deprives ratepayers of the benefit of a comprehensive review and prudence determination. In general, the scope of the Commission's consideration of the Company's proposal should reflect a multi-pollutant approach to evaluating the known and likely costs of continued operation and retrofit, rather than considering one regulation at a time.

Q Please briefly describe the purpose and impact of National Ambient Air Quality Standards (NAAQS).

A NAAQS set maximum air quality limitations that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are stationed in various cities throughout the U.S., or through air quality dispersion modeling. If, upon evaluation, states have areas found to be in "nonattainment" of a particular NAAQS, states are required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are attained and maintained. EPA has established short-term and/or annual NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter (measured as particulate matter less than or equal to 10 micrometers in diameter (PM_{10}) and particulate matter less than or equal to 2.5 micrometers in diameter ($PM_{2.5}$)), and lead. EPA is required to periodically review and evaluate the need to strengthen the NAAQS if necessary to protect public health and welfare. For example, EPA is currently evaluating the NAAQS for ozone and is likely to make that standard more stringent based on the latest science regarding health effects.

In nonattainment areas, sources must comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT) to bring the areas into attainment of the NAAQS. New major sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER) as well as obtain emission offsets.

Q: Which NAAQS are most likely to impact the Company's solid-fueled assets at issue in this case?

A The 1-hour SO_2 NAAQS, the 8-hour Ozone NAAQS, and the $PM_{2.5}$ NAAQS are likely to have the greatest impacts on Cleco's solid-fuel fired assets due to the cost of the controls that may be required to help meet compliance obligations.

Q Please briefly describe the 1-hour SO_2 NAAQS.

A In 2010, the EPA promulgated a new 1-hour standard for SO_2, which became effective in June of that year. The new 1-hour SO_2 standard set a limit – 75 ppb or 195 µg/m3 – on the allowable concentration of SO_2 in the ambient air for each hour of the day. An area is in compliance with—or attaining—the standard if the three-year average of the fourth highest daily maximum 1-hour average concentration for each year is less than or equal to 75 ppb.

As mentioned above, for most NAAQS, EPA determines whether an area is attaining the standard by reviewing ambient air quality monitoring data from the area. With SO_2, however, EPA found that, due to the limited geographic coverage of the existing monitoring network, there was not sufficient monitoring data available in all areas to determine whether the standard was being met. Because of these data limitations, and because of the "source-oriented" nature of the 1-hour SO_2 standard, EPA determined that refined dispersion modeling may also be used to determine whether an area with significant SO_2 sources is meeting the standard or not.[58]

Q What is the current status of the 1-hour SO2 NAAQS?

A In July 2013, EPA made initial "non-attainment" designations for a limited number of areas that had sufficient monitoring data to demonstrate noncompliance with the 1-hour SO_2 standard. EPA found that only 29 areas in 16 states had sufficient monitoring data to make these initial non-attainment

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[58] U.S. Environmental Protection Agency, "Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard," February 6, 2013.

findings.[59] In Louisiana, St. Bernard Parish was designated as non-attainment. The Company's units are located in De Soto and Rapides parishes, where compliance status has not yet been determined. Another round of designations is anticipated based on either the installation of new ambient air monitors or the submission of dispersion modeling.

Importantly, the state of Louisiana has an obligation to submit infrastructure state implementation plans (ISIPs) for areas currently "unclassifiable" within three years of when the SO_2 NAAQS was promulgated (i.e. by 2013) to show that the NAAQS is being implemented, enforced, and maintained.[60]

Q What are the implications of the 1-hour SO_2 NAAQS for Cleco's assets?

A. If the state or EPA determines that the counties containing or surrounding RPS2 or DHPS are in nonattainment, Cleco could be required to install more rigorous controls at these units to help bring the state into compliance with the NAAQS.

[redacted] I discuss this particular problem in further detail later.

Q Please briefly describe the 8-hour Ozone NAAQS.

A In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA's panel of science advisors, it would

[59] US EPA, 2013. Final Nonattainment Areas for the 2010 SO2 Standards, Round 1 – July 2013. http://www.epa.gov/airquality/sulfurdioxide/designations/pdfs/july2013SO2nonattainmentcounties.pdf

[60] The 75 ppb 1-hour SO_2 NAAQS were promulgated June, 2010. 75 FR 35520. June 22, 2010.

reconsider the 75 ppb standard. In January 2010, EPA proposed lowering the 75 ppb primary ozone standard to between 60 and 70 ppb.

On September 2, 2011, however, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the Agency's normal 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone is due in 2013, though EPA has indicated that it will likely need more time.

If EPA were to propose a standard in the 60 to 70 ppb range (as it did in 2010), it is likely that additional areas in Louisiana will be designated as non-attainment for the new standard. This could drive significant additional NOx emission reduction requirements. Specifically, it could mean that the selective non-catalytic reduction technology (SNCRs) the Company recently installed on these units will not reduce NOx to the extent needed to comply with a more stringent 8-hour ozone standard and that additional controls, such as selective catalytic reduction technology (SCRs), will be needed.

Q Please briefly describe the $PM_{2.5}$ NAAQS.

A In 1997, the EPA established the first ever annual and 24-hour $PM_{2.5}$ NAAQS at 15 micrograms per cubic meter ($\mu g/m^3$) and 65 $\mu g/m^3$, respectively. In 2006, the EPA lowered the 24-hour $PM_{2.5}$ standard to 35 $\mu g/m^3$ and retained the 15 $\mu g/m^3$ annual standard. The 2006 PM2.5 standards were primary drivers behind the EPA's 2005 CAIR and 2011 CSAPR rules, which were designed to lower NOx and SO_2 emissions from electric generating units in affected states that significantly contribute to $PM_{2.5}$ non-attainment areas in other states.

In December 2012, EPA lowered the annual $PM_{2.5}$ standard from 15 $\mu g/m^3$ to 12 $\mu g/m^3$ and retained the 24-hour standard at 35 $\mu g/m^3$. EPA will make final area designations for the new standard by December 2014, at which time states with non-attainment areas will have three years to develop a state implementation plan (SIP) outlining how they will reduce pollution to meet the standard by 2020.

Particulate matter is made up of primary particles, which are emitted directly from a source, as well as secondary particles, which are formed through reactions in the atmosphere of chemicals such as SO_2 and NOx.[61] The $PM_{2.5}$ NAAQS, therefore, requires control of not just directly emitted particles but also of SO_2 and NOx – the precursors of secondary particles.

9. <u>COMPANY'S RISK PROFILE UNDER SO2 NAAQS</u>

Q How has Cleco characterized its risk profile under the SO_2 NAAQS?

A In response to Sierra Club Data Request 1-41, Mr. Matthews states that "given the status of the 1-hour SO2 NAAQS implementation process, there is no basis upon which to conclude that either generating station [RPS2 or DHPS] will be located in an SO2 nonattainment area, or that existing SO2 emissions from either facility will cause or contribute to a violation of the 2010 1-hour SO2 standard."

Q Do you agree with Mr. Matthew's characterization?

A No. As I stated before, the 1-hour SO_2 standard became effective in June 2010. In his testimony, Mr. Gregory A. Coco explained that the 1-hour SO_2 standard is a concern for the Company, particularly for RPS2.[62] Furthermore, in Confidential Exhibit GAC-1 to Mr. Coco's testimony, S&L [redacted]

[redacted]

[61] EPA Particulate Matter website: http://www.epa.gov/air/particlepollution/basic.html
[62] Direct testimony of Gregory Coco, page 6, line 21 through page 7, line 4

[redacted]

The S&L report acknowledges [redacted] In discovery, Sierra Club obtained the [redacted] results for RPS2 and DHPS [redacted][64]

[redacted]

If Louisiana (or another party) were to submit dispersion modeling to EPA that shows RPS2 and DHPS causing exceedances of the 1-hour SO_2 standard, both Rapides (RPS2) and De Soto (DHPS) parishes could be designated as nonattainment areas in EPA's next round of designations.

Q Will the Company's preferred option for RPS2 be adequate for compliance with the 1-hour SO2 standard?

A No, I don't believe it will. The Company relied on the S&L analysis (Exhibit GAC-1) to choose a preferred option ([redacted]) that would be capable of

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[63] Exhibit GAC-1 at 12-13.
[64] Data Response SC 1-38.1, Attachment C. Attached as Exhibit JIF-23.
[65] Data Response SC 1-38, Attachment E. Attached as Exhibit JIF-23.
[66] Data Response SC 1-38, Attachment E at p.1. Attached as Exhibit JIF-23.

complying with MATS. [redacted][67] [redacted]”[68]

Q [redacted]

A [redacted] This is an annual average of RPS2’s actual emissions[69], rather than the 1-hour average that the state would impose to provide for NAAQS compliance. I used EPA’s Air Markets Program Data to review hourly SO_2 emissions from RPS2 since 2010. In the last three years, RPS2 emitted more than 0.60 lb/MMBtu for 17% of its operating hours in 2010, more than 24% of the time in 2011, and more than 53% of the time in 2012. Based on historical peak emissions rates, RPS2 would need to achieve up to [redacted] SO_2 removal efficiency with a DSI + FF control system to hit the “[redacted]”. This is probably unrealistic for the DSI being built at RPS2.

[67] Exhibit GAC-1 at 13.
[68] Exhibit GAC-1 at 13
[69] Rodemacher 2’s permitted emission rate is actually twice this at 1.2 lb/MMBtu.

Q What is a reasonable upper limit on SO_2 removal achievable by a DSI system?

A According to Babcock and Wilcox, when controlling for SO_2 and hydrochloric acid (HCl), DSI can achieve "80%+" SO_2 removal when "used on small boilers/industrial units [less than] 300 MW."[70] RPS2 is a 523 MW unit. Babcock and Wilcox also note that, "if higher removal rates [are] required, sorbent loading to [the fabric filter] must be evaluated."[71]

Nalco Mobotec, a supplier of combustion pollution technology including DSI, asserts that DSI can be applied on units up to 500MW and achieve between 50 and 80 percent removal of SO_2.[72] RPS2 is larger than Nalco's recommended limit for DSI systems and would likely need to operate at or above the efficiency threshold in order to avoid causing exceedances of the 1-hour SO_2 standard. Based on these two technical reports, RPS2 is likely too big for a DSI system to achieve [redacted][73]

Further, when describing the DSI technology in a 2010 report, S&L states that 70 – 75% efficiency is "generally achieved with a [fabric filter]," and states that the maximum efficiency of a DSI system with milled Trona and a fabric filter is 90%.[74] S&L does not state if such high efficiencies have ever been achieved on units as big as RPS2. Even if RPS2 could achieve these exceptional efficiencies, in order to do so the generator would have to increase its Trona injection

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[70] Campobenedetto, E.J., Silva, A.A.. "Low Cost Multi-Pollutant Control Solution Demonstrations." Presented at Air & Waste Management Association Annual Conference, Orlando, FL, June 21-24, 2011.
[71] Id.
[72] NALCO, Mobotec, "Dry Sorbent Desulfurization Systems." Retrieved online, www.nalco.com 10/31/2013. Available: http://www.nalco.com/mb/technology/dry-sorbent-injection.htm.
[73] SC DR 1-60(a).
[74] Sargent & Lundy, "Dry Sorbent Injection Cost Development Methodology." August 2010. Pp. 4 & 9.

significantly, which would likely increase costs dramatically – from [redacted] a year to over $14 million a year (2012$).[75]

Q If DSI is not sufficient to meet the 1-hour SO_2 standard at RPS2, what additional controls might be necessary?

A In its MATS compliance white paper for RPS2 [redacted]

Q When might additional controls be required for compliance with the SO_2 NAAQS?

A While EPA's current proposal[76] for its next round of non-attainment designations would require final designations by the end of 2017 and final attainment demonstrations in late 2019, I believe these controls could be required as early as the beginning of 2017.

Clean Air Act section 110(a) requires states to submit state implementation plans (SIPs) that implement, maintain, and enforce a new or revised national ambient air quality standard within three years of EPA issuing the standard. These SIPs are known as Infrastructure SIPs. Section 110(a)(2)(a) of the Clean Air Act requires that infrastructure SIPs "include enforceable emission limitations…as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements" of the Clean Air Act. This includes meeting the new 1-hour SO_2 standard.

Louisiana submitted revisions to its infrastructure SIP to EPA on June 10, 2013.[77] The state's Infrastructure SIP did not include enforceable emission limitations on

[75] Based on Sargent & Lundy, "Dry Sorbent Injection Cost Development Methodology." August 2010. Total unit cost, not Cleco portion. [redacted]
[76] U.S. Environmental Protection Agency, "Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard," February 6, 2013.
[77] See US EPA, Status of State SIP Infrastructure Requirements. Online only. Viewed on November 8, 2013. Last updated 11/3/2013. http://www.epa.gov/oar/urbanair/sipstatus/reports/la_infrabypoll.html

large SO_2 sources like RPS2 or DHPS, despite the Clean Air Act requirement to do so. A letter from the Sierra Club to the Louisiana Department of Environmental Quality (LDEQ) on LDEQ's proposal[78] lays out the requirements for Infrastructure SIPs and identifies several inadequacies in the LDEQ's submittal that suggest EPA will reject the state's plan. EPA has until December 10, 2014 to take final action on Louisiana's infrastructure SIP submittal, though it may act before that time. A disapproval of the plan would then trigger a two-year clock in which the state can fix the plan or the EPA will promulgate a Federal Implementation Plan (FIP) requiring enforceable emission limits no later than December 10, 2016.

Furthermore, including enforceable emission limits on RPS2 and DHPS at levels that dispersion modeling show could avoid exceedances of the 1-hour SO_2 standard would help the state avoid additional non-attainment designations and the obligations that come with such designations. Any such limits must ensure that the sources' emissions comply with the standard on an hourly basis, including during start-up, shut-down, and malfunction periods, and not only on a 30-day average basis [redacted][79].

Q Are there any additional problems you identified in the Company's assessment of its obligations under the 1-hour SO_2 standard?

A There are a number of discrepancies in the SO_2 modeling we received in response to Sierra Club Data Request 1-38 that affect our ability to fully utilize the information provided.

[redacted][80] [redacted]

[78] Attached as Exhibit JIF-28

[79] See Exhibit GAC-2 at 14

[80] November 2012 renewed Title V permit for Brame Energy Center available on Louisiana's EDMS website: http://edms.deq.louisiana.gov/app/doc/querydef.aspx

[redacted]

Second, the Title V permit lists the actual stack height of Rodemacher Unit 2 as 250 feet. [redacted].[81] [redacted]

Aside from these possible errors in the dispersion modeling, the Company's assessment of the implications of that modeling raises concerns. In his response to Data Request SC 1-38, Mr. Matthews provides several reasons why he believes that the dispersion modeling done on the Company's behalf can be disregarded. For example, Mr. Matthews states that EPA's May 2013 Draft NAAQS Designation Modeling Technical Assistance Document [redacted]" good engineering practice (GEP) [stack] height [redacted][82] [redacted]

[81] Attached as Exhibit JIF-23.
[82] *See* Data Response to SC 1-38.1 Attachment C at SC-006736, SC-006744 and Attachment D at SC-006758, SC-006761. Attached as Exhibit JIF-23.

Q Do you agree with Mr. Matthew's interpretation of GEP stack height?

A No. This is not my understanding of EPA's Technical Assistance Document. GEP stack heights are used in dispersion modeling to mitigate the effect of stack heights that are in *excess* of what has been determined to be necessary to avoid "excessive concentrations of any air pollutant in the immediate vicinity of the source"[83] since emission limits are generally set based on GEP.[84] I do not think the guidance promotes the use of a hypothetical higher stack height to avoid the identification of air quality problems in dispersion modeling.

The Code of Federal Regulation (CFR) defines good engineering practice stack height for units such as RPS2 as the greater of "65 meters measured from the ground-level elevation at the base of the stack" or "The height demonstrated by a fluid model or a field study approved by the EPA State or local control agency, which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures or nearby terrain features."[85]

Mr. Matthews does not explain how the Company determined that 183 meters – nearly three times higher than the default established by EPA in its regulations – is GEP stack height for the RPS2 Unit.

Q What are the implications of these likely 1-hour SO_2 NAAQS compliance requirements on RPS2 and DHPS?

A At the strict end of 1-hour SO_2 NAAQS implementation, LDEQ could require, as part of its infrastructure SIP, strict SO_2 emission limitations on the plants in order to demonstrate that the areas surrounding the plants will comply with the 1-hour SO_2 standard. I assume that a strict scenario for implementation of the 1-hour SO_2 standard would require the installation of a dry flue gas desulfurization unit

[83] (42 U.S.C. 7423(c))
[84] The Code of Federal Regulations (C.F.R.) explains that emission limits required of a source "must not be affected by so much of any source's stack height that exceeds good engineering practice." 40 C.F.R. §51.164.
[85] 40 C.F.R. §51.100(ii).

(FGD) at RPS2 by the end of 2016, and a re-build (i.e. new) of the wet FGD at DHPS to replace the smaller and older "polishing" unit there with a full scrubber. For proxy costs, I use S&L's estimate for the cost of a dry FGD [redacted])[86] at RPS2, and use a publicly available costing mechanism from EPA (designed by S&L)[87] to estimate the capital cost of a full wet FGD at DHPS ($341 million).

At the lenient end of SO_2 NAAQS implementation, I assume EPA does not require LDEQ to impose strict emission limits on RPS2 and DHPS under its Infrastructure SIP and instead, the state installs new monitors for SO_2 in regions around large sources such as RPS2 and DHPS. Under this circumstance, the monitors would be put in place in 2017, would collect data for three years (2020), EPA would approve new designations (2020), and regions around RPS2 and DHPS would be found to be in non-attainment. After a state implementation plan process, I assume that the state would require an FGD at RPS2 in 2022. In the lenient case, there is the possibility that the existing FGD at DHPS could be upgraded or retrofit for little or no cost.

10. COMPANY'S RISK PROFILE UNDER THE CROSS STATE AIR POLLUTION RULE

Q Please briefly describe the purpose and impact of the Cross State Air Pollution Rule.

A The Cross State Air Pollution Rule (CSAPR), finalized in 2011, established the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's $PM_{2.5}$ and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia on August 21, 2012. In June 2013, the U.S. Supreme Court announced that it would review that decision, creating the possibility it could reinstate CSAPR. Even if EPA fails to salvage CSAPR through the courts, the EPA must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. When the D.C.

[86] Confidential Exhibit GAC-1, Table 5-1.
[87] See "Documentation for EPA Base Case v.4.10" for the Proposed Transport Rule. Available at http://www.epa.gov/airmarket/progsregs/epa-ipm/BaseCasev410.html

Circuit vacated CASAPR, it ordered EPA to implement the 2005 Clean Air Interstate Rule in CSAPR's place to address those "good neighbor" obligations.

As it awaits a decision from the Supreme Court, EPA has continued to work on a replacement for CSAPR that meets the D.C. Circuit's requirements.

Q How will the $PM_{2.5}$ and Ozone NAAQS, and next iteration of CSAPR impact RPS2 and DHPS?

A NOx is a precursor to both $PM_{2.5}$ and ozone, meaning that areas that are not in attainment for these two pollutants will seek the most effective source controls for precursors. Since large emissions sources – such as coal-fired generating stations – contribute disproportionately to emissions of these precursors and are effectively controlled with post-combustion controls such as SCR (selective catalytic reduction), I assume that if areas of Louisiana within the dispersion area of RPS2 and DHPS are found to be in non-attainment for the $PM_{2.5}$ or ozone standards, the state and EPA could require rigorous NOx controls at these units to meet the standards. The EPA has withdrawn the last draft update to the ozone NAAQS, but had that NAAQS been promulgated, most of the monitors in Louisiana would show violations,[88] and hence require Louisiana to develop a rigorous SIP with tight limits on NOx emissions from major sources.

Similarly, if the next version of the interstate transport rule finds that NO_x sources in Louisiana contribute to ozone or $PM_{2.5}$ pollution in downwind states (as did the vacated version), then large sources in Louisiana could either be required to install controls or purchase NO_x allowances at high prices. Based on the promulgation of new $PM_{2.5}$ NAAQS and expected ozone NAAQS, I'd expect that the next version of CSAPR will be more rigorous than the vacated version.

At the strict end of the spectrum, I assume that the recently installed SNCR controls installed at RPS2 and DHPS would generally not be considered rigorous enough to help the state meet air quality standards, therefore the state would

[88] *See* EPA's "Counties Projected to Violate Primary 8-hour Ground-Level Ozone Standard in 2020" at: http://www.epa.gov/air/ozonepollution/pdfs/CountyOzoneLevels2020primary.pdf

require SCR controls for compliance. If designations for $PM_{2.5}$ are made this year, and a new ozone standard is promulgated in 2014 or 2015, a SIP could be finalized by 2017, requiring controls as early as 2018. I used a publicly available costing mechanism from EPA (designed by S&L)[89] to estimate the capital cost of SCR at RPS2 ($112 million) and DHPS ($145 million), installed in 2018. The costs of installing SCR at DHPS could be even higher if, [redacted][90]

At the lenient end of compliance, I assumed that either the SNCRs would be found to be a reasonable interim technology, or that the SIP process would be delayed by four years, eventually requiring state of the art NOx controls by 2022. I used the same capital costs as noted above.

Q Is the Company concerned about the potential for an SCR requirement?

A Yes. [redacted]

> [redacted][91]

I assume that this concern has not diminished since 2011.

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[89] See "Documentation for EPA Base Case v.4.10" for the Proposed Transport Rule. Available at http://www.epa.gov/airmarket/progsregs/epa-ipm/BaseCasev410.html

[90] See GAC-2, at p.7.

[91] SC 3-59.1 Attachment B. Attached as Exhibit JIF-13.

11. COMPANY'S RISK PROFILE UNDER THE COAL COMBUSTION RESIDUALS RULE

Q Please briefly describe the purpose and impact of the proposed Coal Combustion Residuals rule.

A Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments; regulations governing the structural integrity and leakage from these installations vary. However, the risk associated with these installations was dramatically revealed in the catastrophic failure of the ash slurry containment at TVA's Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River.[92]

On June 21, 2010, EPA proposed regulation of ash and flue gas desulphurization (FGD) wastes, or "coal combustion residuals" (CCR) as either a Subtitle C "hazardous waste" or Subtitle D "solid waste" under the Resource Conservation and Recovery Act (RCRA).[93]

If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system applies to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would also implement minimum requirements for dam safety at impoundments.

Under a "solid waste" Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.

The EPA is currently evaluating which regulatory pathway will most effectively protect human health and the environment without resulting in unintended

[92] See TVA Kingston Ash Recovery Project at http://www.tva.com/kingston/pdf/ash_recovery_2-26.pdf (viewed June 18, 2012)
[93] 75 Fed. Reg. 35127. (June 21, 2010)

consequences or resulting in unnecessarily burdensome requirements. On October 29, 2013, the U.S. District Court for the District of Columbia gave EPA until December 29, 2013 to submit a plan for finalizing its delayed CCR rule. This suggests that a final CCR rule is imminent.

Q How will the CCR rule impact RPS2 and DHPS?

A The impact of the final CCR rule will vary from station to station, depending on circumstances, and current practices and infrastructure. However, many utilities have started to develop proxy costs to estimate the impact of this rule, and take it into account in planning.

In the 2011 SEC filing, Cleco discusses the risk from the CCR rule:

> Either of the EPA proposed options represents a shift toward more comprehensive and costly requirements for CCR disposal and management, but the Subtitle C option contains significantly more stringent requirements and <u>will require greater capital and operating costs to comply with that rule</u>, if finalized. Both options seem to allow the continued use of ash for certain beneficial reuses. <u>Depending upon the outcome of the final rule, this regulatory proposal could significantly impact the manner and cost in which Cleco Power manages its CCRs.</u> The final CCR rule is now expected to be issued by the EPA in late 2012 or early 2013. <u>Any stricter requirements imposed on coal ash and associated ash management units by the EPA as a result of this new rule could significantly increase the cost of operating existing units or require them to be significantly upgraded</u>. [Emphasis added][94]

[redacted][95]

[94] Cleco 2011 10-K SEC filing, Exhibit JIF-20. Page 16.
[95] SC 3-59.1 Attachment B.

I have estimated costs for compliance with the CCR rule based on publicly available estimates from the Electrical Power Research Institute (EPRI)[96] and by a consultancy working for Edison Electric Institute (EEI). [97]

In the strict case, I assume a compliance obligation under Subtitle D, required in 2019. I estimate the capital costs of compliance at RPS-2 at $73 million, and DHPS at $104 million. In the lenient case, I assume compliance is not required until 2021.

12. COMPANY'S RISK PROFILE UNDER THE EFFLUENT LIMITATION GUIDELINES

Q Please briefly describe the purpose and impact of the proposed Effluent Limitation Guidelines (ELG).

A The Clean Water Act requires EPA to develop "effluent limitation guidelines" (ELGs) – standards for what large industrial sources of water pollution can discharge into nearby waters.[98] These standards must be based on the best-performing technology in the industry that is technically and economically achievable across the industry, and must be updated at least once every five years to reflect improving treatment technology and move towards the Clean Water Act's goal of eliminating water pollution.

On June 7, 2013, EPA proposed standards for bottom ash and fly ash handling water, impoundment and landfill leachate, wastewater from wet FGD systems, flue gas mercury control systems, regeneration of the catalysts used for SCR, among other waste streams.[99].

EPA's proposed rule contains several alternative compliance options. Nearly all of these options require zero discharge of fly ash and bottom ash handling waters,

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[96] EPRI, 2010. Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act.
[97] EOP Group, Inc. 2009. Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal-Fired Electric Utilities.
[98] See 33 U.S.C. § 1311; 40 C.F.R. Part 423 (current ELGs for steam electric generating unit source category).
[99] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Proposed Rule), 78 Fed. Reg. 34,432 (June 7, 2013).

either through conversion to dry ash handling or implementation of closed loop wet ash handling system. Likewise, most options will require chemical precipitation and biological treatment of wastewater generated by wet FGD systems like that in use at DHPS. EPA has made very clear that the settling ponds widely used in the industry are inadequate to reduce concentrations of dissolved toxic metals like selenium, mercury, and arsenic. EPA is required by a consent decree to finalize the ELG rulemaking by May 2014.

Q How will the effluent limitation guidelines impact RPS2 and DHPS?

A Similarly to the CCR rule, the ELGs will vary from station to station, depending on circumstances, and current practices and infrastructure.

A review of the Louisiana Pollutant Discharge Elimination System Permit for RPS2 shows that the plant discharges bottom ash handling water and fly ash handling water.[100] As noted above, EPA will likely require closed-loop or dry bottom ash handling systems, and dry fly ash handling systems. These systems impose both capital costs for new treatment facilities, and higher operational costs.

In the 2011 SEC filing, Cleco discusses the risk from the ELG rule:

> The revised effluent limitations guidelines could require costly technological upgrades at Cleco's existing facilities, in particular if additional wastewater treatment systems are required to be installed.[101]

[100] See Louisiana Dept of Envtl. Quality, Proposed LPDES Permit No. LA0008036, at Part I, p. 9 (describing discharges from Outfall 401), issued July 11, 2012, Exhibit JIF-31..The Dolet Hills facility also discharges bottom ash wastewater and wet FGD wastewater, adding additional treatment costs under the ELG rule. See Louisiana Dept of Envtl. Quality, Final LPDES Permit No. LA0062600, at Part I, p. 4, 12 (describing discharges from Outfalls 002 and 010), issued Oct. 29, 2012, Exhibit JIF-32.

[101] Cleco 2011 10-K SEC filing, Exhibit JIF-20. Page 16.

I have estimated costs for compliance with ELGs based on modeling parameters available in EPA's regulatory impact assessment of the ELG rule.[102,103]

In the strict case, I assume a stringent compliance obligation[104] required in 2017. I estimate the capital costs of compliance at RPS2 at $22 million, and DHPS at $49 million, with additional annual fixed O&M costs of $3.1 and $7.0 million, respectively.

In the lenient case, I assume the least stringent compliance obligation[105] required in 2022. I estimate the capital costs of compliance at RPS2 at $3 million, and DHPS at $6 million, with additional annual fixed O&M costs of $1.2 and $2.6 million, respectively.

13. <u>COMPANY'S RISK PROFILE UNDER THE COOLING WATER INTAKE RULE</u>

Q Please briefly describe the purpose and impact of the proposed Cooling Water Intake Rule.

A On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.[106] Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The proposed rule provides that:

[102] US EPA, 2013. Regulatory Impact Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.
[103] US EPA, 2013. Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category
[104] Equivalent to the 4a Option considered in the proposed rule
[105] Equivalent to the 3a Option considered in the proposed rule
[106] 33 U.S.C. § 1326.

- Existing facilities that withdraw more than two million gallons per day would be subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day would be required to conduct an entrainment characterization study for submission to the Director to establish a "best technology available" for the specific site.

It is unknown if final implementation of the rule will effectively require "open cycle" cooling (i.e. those that withdraw from and discharge hot water directly to rivers or lakes) to retrofit with "closed cycle" cooling towers, or if advanced fish screens will prove sufficient.

Some utilities have assumed, for forward modeling purposes, that a final rule will require closed cycle cooling.

Q How will the cooling water intake rule impact RPS2 and DHPS?

A DHPS already uses closed cycle cooling, so I assume that compliance costs will be negligible at this unit. RPS2, however, uses Lake Rodemacher as a giant cooling reservoir, drawing in large quantities of lake water to provide cooling to the plant's systems. I assume that the finalized version of this rule would apply to RPS2, and in the Company's 2011 SEC filing, the Company appears to agree.

> As presently drafted, portions of the proposed rule could apply to all of Cleco's fossil fuel steam electric generating stations. Until more thorough studies are conducted, including technical and economic evaluations of the control options available and a final rule is issued, Cleco remains uncertain which technology options or retrofits would be required to be installed on its affected facilities. However, the costs of required technology options and

retrofits could be significant, especially if closed cycle cooling is required.[107]

In the strict case, I assume a $20 million cooling tower is required at RPS2 in 2018. In the lenient case, I assume that the Company could achieve compliance through fairly low-cost measures, such as fine-mesh intake screens; I do not calculate a cost for these measures.

Q How do these proposed and impending environmental rules change the economic picture for RPS2 and DHPS?

A Overall, the implementation of the rules I have described here has a significant impact on the outcome of the Company's analysis. Without even accounting for greenhouse gas regulations, but simply assuming that the Company will have to meet the least stringent environmental compliance obligations discussed above, the benefit of the retrofits shrinks markedly. At AEO 2013 gas prices, the benefit of retrofitting RSP2 has shrunk from $200 million to $3 million – a value well within the margin of error – while the benefit of retrofitting DHPS is reduced by nearly 70% to $113 million. With an assumption that the EPA will implement a stricter set of environmental compliance obligations, both of the coal units are liabilities to Cleco and its ratepayers (see Table 7, below). Retrofitting RPS2 and/or DHPS result in net losses to the Company.

Table 7. Cleco Analyses with AEO 2013 gas price and lenient/strict environmental regulations with <u>no</u> CO_2 price. PVRR of retrofit and retirement scenarios (millions 2015$).

Capacity Correction, Lenient Environmental Regulations: AEO 2013 Gas			
	RPS2	**DHPS**	**RPS2 & DHPS**
Retrofit	$6,647	$6,647	$6,647
Retire	$6,666	$6,745	$6,825

[107] Cleco 2011 10-K SEC filing, Exhibit JIF-20. Page 16. Contrary to this admission in its statement to investors, in response to discovery propounded by Staff, the Company asserted that Section 316(b) regulations would have no impact on Rodemacher 2, because Lake Rodemacher is not a water of the United States. *See* Cleco Response to Staff DR 1-4. This discovery response appears to contradict the existing LPDES permit for Brame Energy Center (LA0008036). The LDEQ Fact Sheet and Rationale for that permit contains a section discussing the cooling water intake structure requirements for the plant, based on its impacts to fisheries in Lake Rodemacher. *See* Louisiana Electronic Document Management System Document #8453540.

Benefit of retrofit	**$19**	**$98**	**$177**
Capacity Correction, Strict Environmental Regulations: AEO 2013 Gas			
	RPS2	**DHPS**	**RPS2 & DHPS**
Retrofit	$7,021	$7,021	$7,021
Retire	$6,965	$6,820	$6,825
Benefit of retrofit	**($56)**	**($201)**	**($196)**

When I consider the impact of both impending environmental obligations and CO_2 prices, it is clear that continuing generation at RPS2 and DHPS poses a significant threat to Cleco's ratepayers. The results of this re-analysis suggest that retrofitting both units leaves ratepayers stuck paying more than $350 million more than simply replacing these units with new gas units if environmental regulations are lenient. If regulations are promulgated with strict requirements, Cleco's ratepayers would lose nearly $700 million on the Company's bet (see Table 8, below).

Table 8. Cleco Analyses with AEO 2013 gas price and lenient/strict environmental regulations with Synapse CO_2 prices. PVRR of retrofit and retirement scenarios (millions 2015$).

Capacity Correction, Lenient Environmental, Synapse CO2: AEO 2013 Gas			
	RPS2	**DHPS**	**RPS2 & DHPS**
Retrofit	$9,141	$9,141	$9,141
Retire	$9,001	$8,860	$8,778
Benefit of retrofit	**($140)**	**($282)**	**($363)**
Capacity Correction, Strict Environmental, Synapse CO2: AEO 2013 Gas			
	RPS2	**DHPS**	**RPS2 & DHPS**
Retrofit	$9,515	$9,515	$9,515
Retire	$9,300	$8,935	$8,778
Benefit of retrofit	**($216)**	**($580)**	**($737)**

In my opinion, taking the position that the EPA will fail to promulgate required environmental regulations or restrict emissions of CO_2 is a very long-odds bet, and not one that Cleco's ratepayers should be required to take.

It is my opinion that a reasonable mid-level estimate of future obligations is the more lenient implementation of environmental rules, along with the Synapse mid-case CO_2 price. After adjusting for a balanced capacity analysis and AEO 2013 gas prices, both RPS2 and DHPS are significant ratepayer or shareholder liabilities.

14. MODEL ASSUMPTIONS INCONSISTENT WITH PRE-FILED TESTIMONY AND 2012 IRP

Q Do you have any other concerns with the Company's filing or modeling accompanying this application?

A Yes. In reviewing the model output, I found discrepancies between statements made in Mr. Sharp's supplemental testimony and the model. I also believe that the production cost model is inconsistent with assumptions in the 2012 IRP.

Q What in the model was inconsistent with Mr. Sharp's testimony?

A Mr. Sharp made several corrections to the initial analysis. These corrections were filed as supplemental testimony in April 2013. The first two of these corrections (i and ii), regarding the price curve for lignite and the heat rate for the new NGCC units, are inconsistent with the model results. The next three (iii-v) are fairly significant and basic analytical errors, and hopefully do not reflect the care and quality commensurate with multi-hundred million dollar decisions and investments.

First, Mr. Sharp states that "Cleco Power updated its lignite price curve to remove a decrease in the commodity price beginning in 2026."[108] However, reviewing the output of the model, the cost of lignite takes a significant downturn in real

[108] Supplemental testimony of Richard Sharp, p2, lines 2-5.

terms[109] from [redacted] (2012$) for the rest of the analysis period (see Confidential Figure 4). This trajectory does not comport with Mr. Sharp's testimony.

Considering that in 2013, the Company has paid, on average, $3.42/MMBtu (2012$) for lignite at DHPS,[110] I find the low long-term price questionable. Further, the Company provided an undated document through discovery entitled "[redacted]" that ominously reads, with respect to the lignite supply, "[redacted]"[111]

[redacted]

Confidential Figure 4. Lignite price curve from model and response to SC 3-16.

Secondly, Mr. Sharp states that "the heat rate for new combined cycle gas turbine units was adjusted to 7,050 btu/kWh." [112] The actual heat rates for the 480 and 250 MW NGCCs, culled from the output files provided by the Company, are [redacted], a fair degradation from Mr. Sharp's stated heat rate. Reviewing recent NGCC builds from 2011-2012, I found heat rates (reported for regulatory compliance to EPA) for units greater than 150 MW between 6,398 and 7,193 btu/kWh – with many reporting heat rates under 6,800

[109] Assumes [redacted] inflation rate as used elsewhere in Company analysis.
[110] Compiled from EIA Form 923.
[111] See SC 3-59, Attachment B, page 2 "Background". Attached as Exhibit JIF-13.
[112] Supplemental testimony of Richard Sharp, p2, lines 6-7

btu/kWh.[113] This difference is very significant. At a heat rate of 6,800 btu/kWh, the gas units burn significantly less fuel than at 7,220 btu/kWh as estimated by Cleco. Roughly speaking, if the modeled NGCC units had a heat rate of 6,800 btu/kWh and still produced the same amount of energy, the gas units would be favored by an additional $20-$30 million net present value (2015$) in the low case, and $34-$53 million in the high gas case. This deficiency is biased against the gas unit replacement option.

Q What in the model was inconsistent with the 2012 IRP?

A The 2012 IRP contains a page entitled "Resource Cost Assumptions"[114] where it clearly states assumptions underlying a 480 MW CCGT and a 250 MW CCGT, units directly comparable to those examined in this docket. There are several significant differences, however:

- This analysis assumes a capital cost of $[redacted]/kw for the new NGCC,[115] the IRP states a capital cost of $[redacted]/kW. The IRP assumption would have been $94.5 million (NPV[116], 2015$) favorable to the NGCC selection in the case of the 250 MW NGCC, and $181.4 million in the case of the 480 MW NGCC.
- This analysis assumes a variable O&M cost of $[redacted]/MWh for the 250 MW NGCC and $[redacted]/MWh for the 480 MW NGCC, the 2012 IRP assumes a variable O&M of $[redacted]/MWh. The IRP assumption would have been $36-$46 million (NPV, 2015$) favorable to the NGCC selection, depending on the scenario.

Q Do you have any concerns not associated with the IRP?

A Yes. The Company had an opportunity to avoid a major maintenance outage-cycle at both RPS2 and DHPS under the circumstance that these units were going to

[113] Units identified through EIA Form 860 (2012). Heat rates from hourly emissions reporting data for EPA's Clean Air Markets Data. Positively identified 14 units.
[114] See SC 1-17.1 Attachment A, 2012 IRP. Appendix H- Resource Cost Assumptions. Attached as Exhibit JIF-21.
[115] See SC 2-1, RR Model – 250 MW CCGT/480 MW CCGT, tab "AFUDC – Basis", cell H124.
[116] NPV: Net Present Value

retire. The Company did not consider the opportunity to avoid major life extension projects at both of these units; costs which should have been factored into the avoidable cost analysis.

According to Company documents, DHPS is due for a major outage cycle [redacted] while RPS2 is due for a major outage cycle in [redacted] DHPS will undergo nearly [redacted] in repairs this year, while RPS2 will undergo $[redacted] in repairs.[117] A large fraction of these costs seem to be for life extension work, projects that would not be completed if the units were to be retired in two years, prior to the MATS compliance deadline. Therefore, the Company should have included these avoidable costs in the economic evaluation.

15. CONCLUSIONS AND RECOMMENDATIONS

Q What are your findings?

A The Company's analysis is flawed and deficient, lacks critical information, and does not reflect economic reality. Instead, the analysis appears to have been constructed to justify, rather than appropriately and rigorously test outcomes prior to making a decision.

Two of the units considered for retrofit in this case, RPS2 and DHPS, are likely to be significant economic liabilities for either the Company's ratepayers or the Company's shareholders. If the retrofits are approved, and the units continue operation, ratepayers can be assured of significant future environmental costs that have not been disclosed to this Commission. The Company is aware of these significant costs, but has ensured that none of these costs show up in the public record.

It is my opinion that the Company is engaged in a piecemeal set of retrofits to ensure these units stay in service, and in rate base. As such, I cannot endorse the Company's analysis, these retrofits, or the Company's application to recover costs associated with these retrofits.

[117] It is unclear if these are the Company's costs, or the shared costs for the full unit repairs.

Q **What are your recommendations to this Commission?**

A I recommend that the Commission deny the Company authorization to install the MATS controls at RPS2 and DHPS, and disallow the costs associated with associated with the RPS2 and DHPS MATS control equipment. That disallowance should include not only recovery of and on the capital costs of the Environmental Retrofits, but also any associated operation and maintenance (O&M) costs and costs due to lost output from the affected plants. These costs due to lost output from the affected plants means the cost of replacement power or additional production needed by the Company due to any plant or unit downtime caused by the installation or operation and maintenance of the retrofits. This also includes the cost of additional production or replacement power the company needs due to either parasitic loads or reduced capacity at any plant or unit caused by the operation of the retrofits, less the variable costs of production avoided at the plants or units affected by the installation and operation of the retrofits. The Company should be required to make a compliance filing to document the amount of those costs. That compliance filing should be subject to review and approval in this proceeding by the parties and Commission.

The facts presented in this proceeding demonstrate that the Company's management and decision-making processes is, and has been fundamentally flawed. This does not create an atmosphere of confidence consistent with the usual presumption that utility management is prudent and economical. Therefore, the Commission should also require the company to provide a prompt and full analysis and accounting for the impact of existing and upcoming environmental regulations affecting its entire fleet of coal plants, as well as the full range of options for addressing those regulations, including both supply- and demand-side resources as well as alternatives to continued operation such as retirement or repowering.

Q **Does this conclude your testimony?**

A Yes, it does.