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May 27, 2022

Ms. Chelsea Cancino
Environmental Scientist
Utah Division of Air Quality
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RE: Response to National Park Service questions on Sunnyside Cogeneration Associates Four Factor Analysis – Dry Sorbent Injection Considerations

Dear Ms. Cancino:

Sunnyside Cogeneration Associates (Sunnyside) and Trinity Consultants (Trinity) have prepared this memorandum in response to comments made by the National Park Service (NPS) to Utah Division of Air Quality (UDAQ). The NPS's questions centered around the feasibility of installation of Dry Sorbent Injection (DSI) technology to reduce Sulfur Dioxide (SO_2) emissions. Sunnyside has considered NPS's questions and provided additional information in response that is consistent with its original Four-Factor Analysis and subsequent response to UDAQ's questions in evaluating DSI.

If you have further questions about these responses, please reach out to Brian Mensinger at Trinity or Rusty Netz at Sunnyside for further information.

DISCUSSION OF DRY SORBENT INJECTION

The Regional Haze Rule (RHR) requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. UDAQ prepared a Regional Haze State Implementation plan (SIP) for the second planning period which addresses requirements for periodic comprehensive revisions of implementation plans for regional haze.[1] Throughout this second planning period, UDAQ has consulted with federal land managers (FLMs), Tribes, Utah's surrounding states, as well as environmental advocates, industry stakeholders, and the public.[2] Resulting from this stakeholder outreach, UDAQ received a comment from the NPS regarding the technical evaluation conducted by Sunnyside to further consider addition of SO_2 controls, specifically requesting further evaluation of Dry Sorbent Inject (DSI), at the Sunnyside cogeneration facility. The NPS's comment to UDAQ for the Sunnyside Four-Factor Analysis is as follows.

> *Our review finds that Sunnyside has not provided sufficient justification to exclude dry sorbent injection (DSI) technology as technically feasible. We estimate DSI could remove almost 380 tons/year of SO_2 at around $6,900/ton*

[1] Packet Provided to the Utah Air Quality Board (UAQB) on March 24, 2022 and presented in the April 6, 2022 meeting. DAQ-032-22

[2] Packet Provided to the Utah Air Quality Board (UAQB) on March 24, 2022 and presented in the April 6, 2022 meeting. DAQ-032-22

UDAQ and the Utah Air Quality Board (UAQB) requested that Sunnyside provide a response to the public comment period of UDAQ's proposed Regional Haze SIP addressing NPS' concerns. In support of a comprehensive response, Sunnyside reviewed Regional Haze Regulations codified in 40 CFR 51. Within this regulation EPA stipulates that:

> *The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the* ***costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life*** *of any potentially affected anthropogenic source of visibility impairment.*[3]

The information submitted in this response responds to NPS's question and further supports the four factors analysis submitted on April 8, 2020 and subsequent supporting information submitted to UDAQ on October 15, 2021 to address its review of Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment.[4]

This memorandum addresses components relative to the Four-Factor Analysis as they relate to the installation of DSI controls on Sunnyside's circulating fluidized bed (CFB) boiler through a technical and economic evaluation to further support the stepwise review of emission reduction options in a top-down approach.

The Sunnyside Cogeneration Facility produces steam in a CFB boiler with a design maximum heat input capacity of 700 MMBtu/hr which feeds a steam turbine generator, producing a nominal 58 MW of power. Power produced by the steam generator is sold to the grid. The boiler runs on waste coal from two surrounding sub-bituminous waste-coal piles which are located on land owned or leased by Sunnyside. The waste-coal originates from a coal wash plant that previously removed the ash and sulfur out to the coal, leaving behind waste coal piles. Similar to other waste-coal burning facilities, Sunnyside has the added environmental benefit of utilizing a waste product, cleaning up old mining sites and generating an ash that is used as a beneficial back-fill material for reclamation of the old mining sites.

Technical Feasibility

Dry scrubbers, or dry sorbent injection (DSI), generically refers to the interaction of acid gas compounds, such as hydrogen chloride (HCl), SO_2, and hydrogen sulfide (H_2SO_4), with sorbents, such as hydrated lime, sodium bicarbonate, or trona.[5] The reaction of acid gas compounds with the hydrated lime produces a solid byproduct which is captured in a particulate control device along with any fly ash.[6] This control method can be applied within the CFB boiler or as an external control device.

Controls Inherent to CFB at Sunnyside

Sunnyside currently utilizes DSI inherent to the design of the CFB boiler through injection of limestone just above the combustion chamber for SO_2 control as defined in Sunnyside's Title V air operation permit (#700030004). Specifically, Condition II.A.2 currently states:

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[3] 40 CFR 51.308(f)(2)(i)
[4] 40 CFR 51.308(e)
[5] Trona is a sodium carbonate compound, which is processed into soda ash or baking soda. https://www.wyomingmining.org/minerals/trona/
[6] EPA's Air Pollution Control Fact Sheet for Flue Gas Desulfurization (FGD) – Wet, Spray Dry, and Dry Scrubbers EPA-452/F-03-034

> *"This boiler is equipped with a limestone injection system to the fluidized bed and a baghouse."*

In other words, Sunnyside already has a system designed to inject limestone into the fluidized bed of the CFB boiler to absorb sulfur compounds and thus remove SO_2 from the flue gas. The Title V permit further enforces the following SO_2 emission limits, through a continuous emission monitoring system (CEMS).

> *II.B.2.c Emissions of SO_2 shall be no greater than **0.42 lbs/MMBtu heat input per 30-day rolling average during normal operations**, not including periods of startup, shutdown, maintenance/planned outage, or malfunction.*
>
> *II.B.2.d Emissions of SO_2 shall be no greater than **1.2 lbs/MMBtu heat input per 30-day rolling average**, including periods of startup, shutdown, maintenance/planned outage, or malfunction.*
>
> *II.B.2.e Emissions of SO_2 shall be no greater than **462 lbs/hr based on a 3-hour block average, during normal operations** not including periods of startup, shutdown, maintenance/planned outage, or malfunction.*
>
> *II.B.2.f Emissions of SO_2 shall be no more than 30 percent of the potential SO_2 emission rate (**70% reduction rate**) and no more than **0.6 lb/ MMBTU heat input per 30- boiler operating day rolling average at all times** except during periods of startup, shutdown, or malfunction.*

The enforceable limitations and existing controls specified in Sunnyside's Title V will continue to be implemented and its emission limits achieved with existing measures in place.

Hereafter, control strategies currently implemented within Sunnyside's CFB boiler will be referred to as DSI using limestone. Since 1993, when the boiler was installed, Sunnyside has refined operation, limestone injection rate, and other key performance indicators to reduce SO_2 emissions.

The baghouse associated with this boiler is used to control particulate emissions resulting both from the injection of limestone and fly ash. The current baghouse was made operational in January 1993 and is in marginal condition based on its age.

Add-on DSI

In an effort to ensure all potential DSI configurations were considered, and to address the NPS' comments Sunnyside further evaluated technical feasibility for addon control technologies. As documented in a response to UDAQ questions, dated October 15, 2021, there are several addon control technology configurations for DSI control methods which facilitate interaction of the acid gases and reagents using external equipment including: 1) Hydrated Ash Reinjection (HAR), 2) Spray Dryer Absorber (SDA), and 3) Circulating Dry Scrubber (CDS)/ Circulating Fluidized Bed Scrubber (CFBS). After a complete review of these technologies in the Sunnyside submitted Four Factor Analysis and supplemental response the only addon DSI configuration considered potentially technically feasible is the CDS/CFBS configuration. As a result, this technology was the only technology further evaluated.

CDS/CFBS is a control technique in which the waste gas stream passes through an absorber vessel containing a fluidized bed of hydrated lime and recycled byproduct.[7] Boiler flue gas enters the device at the

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[7] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control

bottom of the up-flow vessel, causing turbulent flow.[8] The turbulent flow increases mixing of the flue gas, solids, and small amounts of water to achieve a high capture efficiency of the vapor phase acid gases contained within the flue gas. The gas and solids mixture then leaves the top of the scrubber and the associated baghouse removes the solid material.[9] These controls have been documented to achieve 50% to 98% control efficiency based on the input parameters and system design.[10]

In many cases the solids entrained in the flue gas are captured and recycled back to the scrubber to capture additional pollutants. [11] A portion of the recycled solids is removed from the baghouse in order to maintain the right quantity of material in the circulating loop. As a result, the baghouse is essential to the design and effectiveness of a CDS/CFBS unit.

A CDS/CFBS system would allow for the use of additional sorbent and has the potential to reduce emissions. However, the full reduction potential as suggested NPS could not be achieved in practice given the overlap in control technique with the currently installed DSI using limestone. This is demonstrated by comparing the emission rate regulated by Sunnyside's current Title V permit to readily available emission limits for similar equipment as published in EPA's RBLC database.[12]

Figure 1. Comparison of Permitted Emission Rates

RBLC ID	Facility Name	Permit Issuance Date	Equipment Details	Control Details	Emission Rate	Control Efficiency
-	Sunnyside	Last Revised 04/30/2018	700 MMBtu/hr (58 MW) CFB Boiler using Waste/Sub-bituminous Coals	Limestone Injection for SO_2 Control	0.42 lb/MMBtu 30-day Rolling Average (Normal Operations)	70%
CO-0055	Lamar Light & Power Plant	2/3/2006	501.7 MMBTU/hr CFB Boiler using Bituminous/Sub-bituminous Coals	Limestone Injection for SO_2 Control	0.103 lb/MMBtu Daily Average	-
WV-0024	Western Greenbrier Co-Generation, LLC	4/26/2006	1070 MMBtu/hr CFB using Waste Coal	Lime Injection and Flash Dryer Absorber	0.14 lb/MMBtu 24-hour Average	98%

Based on the data above, Sunnyside anticipates that the installation of a CDS/CFBS system could achieve a theoretical maximum of 74% further reduction of SO_2, or further removal of 319 ton/year compared to these similar sources.

[8] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)
[9] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)
[10] EPA Air Pollution Control Fact Sheet, Flue Gas Desulfurization (FGD) – Wet, Spray Dry, and Dry Scrubbers, EPA-452/F-03-034
[11] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)
[12] RACT, BACT, LAER Clearinghouse (RBLC) search for Process Code 11.11 for Coal fired Utility and Large Industrial Size Boilers/Furnaces was pulled on April 19, 2022.

Technical Challenges with the Implementation of a CDS/CFBS DSI

As previously discussed, the CFB boiler currently operating at Sunnyside is equipped with a baghouse designed to capture particulate matter resulting from fly ash and the current DSI using limestone. This baghouse became operational in January 1993 and is in marginal condition based on its age.

CDS/CFBS design requires integration of a baghouse following the mixing chamber.[13] To alter the design and re-direct the ducting into the existing baghouse from the boiler and the CDS/CFBS would require custom design plans and detailed computational fluid dynamic engineering. Furthermore, the addition of a CDS/CFBS would increase the amount of particulate matter processed because it represents a secondary addition of reagent to further react with pollutants.

Even if re-engineering of the duct work allowed the existing baghouse to be used, it is likely that the flow patterns produced by the CDS/CFBS would disrupt the flow through the plenum of the baghouse thereby redirecting air flow and eliminating the distribution of air evenly across the compartments.[14] Without an even distribution of air the baghouse is more susceptible to intermittent failure and reduced control efficiency. [15]

Beyond the detailed technical challenges associated with integration of the existing baghouse into a new CDS/CFBS system there is also a plant design challenge. As demonstrated in the photos below, there is insufficient space to install a CDS/CFBS between the boiler and existing baghouse. For all these reasons the CDS/CFBS is no longer an addon technology that can be simply fastened to existing equipment as implied by the NPS's statement. Significant re-engineering time and cost would be required to maintain the CFB boiler's air flow balance and ensure it functions as designed.

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[13] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, [Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)](power-eng.com)

[14] EPA's Air Pollution Control Technology Fact Sheet for Fabric Filter – Pulse-Jet Cleaned Type (also referred to as Baghouses) EPA-452/F-03-025

[15] EPA's Air Pollution Control Technology Fact Sheet for Fabric Filter – Pulse-Jet Cleaned Type (also referred to as Baghouses) EPA-452/F-03-025

Figure 2. General Plant Layout[16]

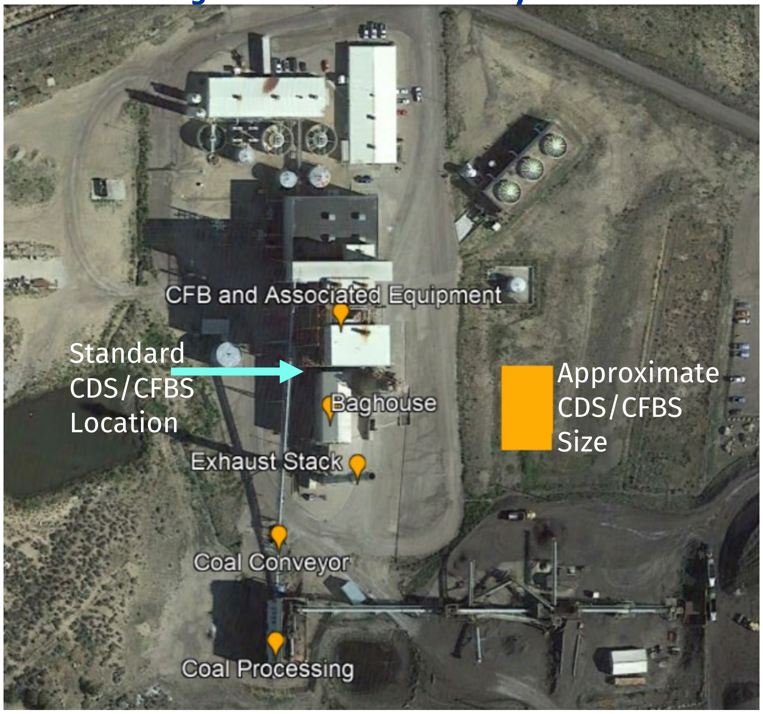

Figure 3. Relative Distance between Current Baghouse and CFB Boiler

Based on the site configuration, the limited space around the CFB boiler would need to be considered to support the addition of a CDS/CFBS system.

[16] Google Earth Imagery used. Approximate CDS/CFBS size determined through an anonymous phone call with system manufacturer.

While these challenges do not represent insurmountable technical challenges, it will impact the design of the CFB boiler and require a complete engineering analysis to maintain flow and mass balance of the system, which in turn does significantly affect the cost of installing the proposed technology.

Economic Feasibility

As presented in its Four Factor Analysis and subsequent responses, Sunnyside developed a site-specific cost analysis to accurately reflect the technical challenges documented as well as the interest rates associated with the financial structure of the corporation and age of equipment. This cost analysis was conducted in accordance with EPA's Cost Control Manual utilizing site specific privately held corporation costs.[17] Sunnyside has further discussed each of the input parameters used in the cost analysis in the following sections, the complete cost analysis, including formulas used, is included in Attachment A.

Baseline SO_2 Emissions

Sunnyside utilized a representative actual emission rate for the CFB boiler based on recent operating conditions and stack testing, 471 tons per year, as a starting point for the cost analysis. This emission rate accounts for the limestone injection already occurring within the unit. Utilizing this emission rate allows the cost analysis to reflect current data and the true cost of removing SO_2 emissions that have the potential to cause regional haze.

SO_2 Removal Efficiency

An SO_2 removal efficiency of 74% was selected for the evaluation of an addon CDS/CFBS DSI configuration. Figure 1 of this report provides RBLC data of comparable units.[18] Comparison of the emission rates provided to current Sunnyside values supports a 74% removal efficiency with the addition of a standard addon control device such as CDS/CFBS, as demonstrated in Figure 4.

Figure 4. Comparison of Standard DSI Configurations to the Limestone Injection Occurring at Sunnyside

Comparison	Sunnyside Emission Rate	Comparable Emission Rate	Demonstrated Further Removal Efficiency
Sunnyside to Lamar Light & Power Plant	0.42 lb/MMBtu	0.103 lb/MMBtu	75%
Sunnyside to Western Greenbrier Co-Generation, LLC	0.42 lb/MMBtu	0.14 lb/MMBtu	67%

Lime Injection Rate

Based on previous guidance from UDAQ, Sunnyside has utilized the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler.[19] This formula states that to achieve a 74% reduction rate, a lime injection rate of 184 lb/hour is necessary.

[17] EPA Cost Control Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology
[18] RACT, BACT, LAER Clearinghouse (RBLC) search for Process Code 11.11 for Coal fired Utility and Large Industrial Size Boilers/Furnaces was pulled on April 19, 2022.
[19] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2/HCl Control Development Methodology, Published April 2017, Prepared by Sargent & Lundy LLC

Annual Operating Time

An annual operating time of 8,031 hours per year reflects a control technology uptime of 92%. This annual operating time allows for maintenance and unexpected boiler and control technology downtime. The downtime percentage considers that the units installed are approximately 30 years old and in marginal operating condition.

Capital Costs

Capital costs were derived from the EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1, Wet and Dry Scrubber for Acid Gas Control. EPA states that on average the total installed cost for "a CDS system capable of achieving greater than 90% sulfur removal was $81 million and the highest total installed costs reported to be $400 million." Sunnyside reduced the average total installed cost to reflect the anticipated control efficiency, 74%, which resulted in an equipment cost of $66.6 million.[20]

CDS/CFBS systems are fairly uncommon within the United States and thus more refined cost data is often difficult to obtain, however this cost is consistent with EPA's statement "Capital costs for units smaller than 50 MW are approximately $1,000/kW."

Capital costs developed by the NPS cite the IPM Model for Dry Sorbent Injection for SO_2/HCL Control Cost Development methodology and are inconsistent with the statements above. Sunnyside reviewed this resource and found the technology description to be more consistent with the DSI limestone injection system currently utilized within the CFB boiler rather than the addon of complex technology such as a CDS/CFBS. Additionally, within the Arkansas Regional Haze Planning Period II SIP the Arkansas Department of Energy and Environment makes the following statement:

> *The IPM model is primarily an economic model that may make unrealistic choices, such as shutting down must-run units or changing fuels at plants not designed for and with no plans for fuel switching.*

As a result, Sunnyside relied upon the costs provided in the EPA Cost Control manual when conducting a cost analysis for the addition of a CDS/CFBS system. Based on the technical challenges previously described Sunnyside anticipated additional retrofit costs and the replacement of the existing baghouse.

Retrofit Costs

EPA states that for retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented.[21] The bounds given for the retrofit factor on a dry system are 0.8 to 1.5. [22] EPA further documents that the retrofit factor should account for site congestion, site access, and capacity of existing infrastructure. The amount of space available near the CFB boiler will significantly impact the costs.[23]

In order to install a CDS/CFBS system the site would need to decommission and demolish the existing baghouse and utilize mechanical experts to fit both the CDS/CFBS and its incorporated baghouse within the

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[20] EPA Cost Control Manual, Section 5 SO2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.1.2 Dry Flue Gas Desulfurization Systems.
[21] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5
[22] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5
[23] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5

currently allocated space. Additionally, because the flow mechanics, namely turbulence, are key to the control efficiency and current operation of the CFB boiler, an engineering firm would need to ensure fluid mechanics were compatible. In addition, to retrofitting a CDS/CFBS onto the CFB boiler, connecting to the existing stack and ensuring sufficient space with the stack is required. Although Sunnyside did not account for moving the stack in its cost analysis, this technical challenge further supports the presented cost estimates. Therefore, these considerations will lead to a custom design and would justify a minimum of a 1.3 retrofit factor.

Inclusion of a Baghouse

As previously mentioned, the current baghouse was made operational in January 1993, and is in marginal condition based on its age. CDS/CFBS design requires integration of the baghouse into the mixing chamber, this connection is not likely to be reliable on the existing equipment given the age of the unit. Furthermore, the addition of a CDS/CFBS would increase the amount of particulate matter processed because it represents a secondary addition of limestone to further react with pollutants.

To alter the design and re-direct the ducting into the existing baghouse from the boiler and the CDS/CFBS would require custom design plans and detailed computational fluid dynamic engineering. Even if a re-engineering of the duct work allowed the existing baghouse to be used, it is likely that the flow patterns produced by the CDS/CFBS would disrupt the flow through the plenum of the baghouse thereby redirecting air flow and eliminating the distribution of air evenly across the compartments.

These design considerations led to the conclusion that, regardless of capacity or current emission rate, inclusion of a replacement baghouse within the cost analysis was warranted. However, Sunnyside prepared a cost analysis without additional baghouse costs to demonstrate the most conservative approach.

Variations in Total Installed Cost

Sunnyside acknowledges that the exact total installed cost for a CDS/CFBS is highly variable and cannot be confirmed without site specific quotes and engineering. In an effort to provide a full consideration of all the potential costs, Sunnyside has utilized the information previously presented to develop a range of total installed equipment costs as presented in the table below:

Figure 5. Range of Total Installed Equipment Costs

Scenario	Total Installed Equipment Cost	Justification of Cost
Minimum	$86.58 Million	EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.1.2 with a ratio applied to be consistent with the 74% control. A minimum retrofit factor of 1.3 has been included.
Maximum	$328.88 Million	EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.1.2 maximum cost with a ratio applied to be consistent with the 74% control. A minimum retrofit factor of 1.3 has been included.

Direct Annual & Overhead Costs, Administrative Costs, Property Taxes, and Insurance

Direct annual and overhead costs such as operating labor, operating materials, maintenance, and utilities were based on standard EPA assumptions as documented in the Cost Control Manual or estimates obtained from Sunnyside specific suppliers as documented in the cost estimate.[24] These assumptions have been tailored to the operation of the CDS/CFBS system proposed whenever possible.

Administrative costs were updated based on UDAQ guidance to be consistent with the those presented by EPA in the template selective catalytic reduction (SCR) cost analysis spreadsheet which accompanies the Cost Control Manual, Section 4 (NOx Controls). Specifically, EPA estimates annual administrative charges based on the formula 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost.

Property taxes are assessed for control equipment; therefore, this tax rate has been taken from the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs.[25]

Insurance rate was based on a 1% of the Total capital investment (TCI) which is documented in the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs.

Capital Recovery (Equipment Life and Interest Rate)

The capital recover factor is calculated via EPA's Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, equation 2.8a and provides a method for determining an annualized capital cost. The inputs for this equation are equipment life and interest rate.

Equipment Life

While EPA generally recommends a 30 year equipment life, the EPA Cost Control Manual states that for retrofits on older combustion units, the remaining life of the controlled combustion unit may be an important factor for determining the expected lifetime for a dry scrubber.[26] Additionally, the EPA issued Reasonable Progress Source Identification and Analysis Protocol (WRAP) for the Second 10-year Regional Haze State Implementation Plans, which further supports this statement by adding "States should combine and annualize these costs over the expected life of the source or the control equipment, whichever is shorter."

The Sunnyside Plant was originally commissioned in the early 1990s, thus the plant has already been running for approximately 30 years. Due to equipment aging, it is estimated that CFB boiler will not be operating beyond an additional 20 years. Thus a 20-year life span has been applied to the mid-range and maximum cost control analyses provided. To provide a complete range, the minimum cost utilizes a 30-year life span, out of the utmost conservatism to demonstrate we are above the Regional Haze SIP cost effectiveness thresholds.

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[24] EPA Cost Control Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology and current costs incurred from Sunnyside's limestone provider.
[25] R307-120-5. Exemptions from Certification, for replacement of a control technology UAC R307-120; therefore, taxes were considered in the cost analysis.
[26] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Indirect Annual Costs (pg. 1-35)

Interest Rate

Sunnyside provided UDAQ with a detailed response supporting the use of a firm-specific interest rate at 7% on March 14, 2022. This letter is provided in Attachment B. In summary a 7% nominal interest rate was chosen due to the age of the plant, site specific financial indicators, and EPA supported values.

Resulting Cost Per Ton Removed

Utilizing the inputs discussed, including a range in total installed equipment cost, and EPA's standard cost control calculation methods Sunnyside anticipates that the cost per ton of SO_2 removed would be between $27,889/ton removed and $118,553/ton removed.[27]

Conclusion

Sunnyside implements DSI using limestone within the CFB boiler currently operating at the site to limit SO_2 emissions. To ensure a complete review was conducted, Sunnyside has further considered the implementation of addon DSI technology, specifically a CDS/CFBS system. In considering the installation of a CDS/CFB system Sunnyside complied site specific technical challenges, the age of the plant, and financial structure to present a range of potential total installed equipment and cost per ton removed values. As a result of this effort, Sunnyside anticipates a cost per ton of SO_2 removed between $27,889/ton removed and $118,553/ton removed. Sunnyside proposes that even the minimum cost per ton removed is above the cost-effective range set for the regional haze program.

[27] EPA Cost Control Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology and Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Indirect Annual Costs (pg. 1-35)

ATTACHMENT A – COST EFFECTIVENESS CALCULATIONS

Dry Scrubber Cost Analysis - CDS/CFBS October 15, 2021 Submittal

Table A-1: CDS/CFBS

Variable		Value	Units
Baseline SO_2 Emissions		471	tons/year
SO_2 Removal Efficiency		74%	Scale Emission Factor with DSI
Total SO_2 Removed		318.91	tons/year - Calculated based on Removal Efficiency
Lime Injection Rate		184	lb/hr (Sargent & Lundy)
Annual Operating Time		8031	hours/year

[1] Assumes control technology uptime of 92% for maintenance and unexpected boiler and control technology downtime.

Table A-2: Dry Sorbent Injection Costs

Cost Item	Factor	Cost	Notes
Captial Costs[1]			
Equipment Cost	A	$66,600,000.00	EPA Cost Control Manual, Section 5 SO2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, with a ratio applied to be consistent with the 74% control orginally estimated
Instrumentation	0.1×A	$6,660,000.00	Per EPA Control Cost Manual
Sales Tax		$0.00	Assume tax exempt per UDAQ Rules
Freight	0.05×A	$3,330,000.00	Per EPA Control Cost Manual
Purchased equipment cost, PEC	B = 1.18×A	$76,590,000.00	Per EPA Control Cost Manual
Direct Installation Costs			
Foundation and Supports	0.12×B	$9,190,800.00	Per EPA Control Cost Manual
Handling and Erection	0.40×B	$30,636,000.00	Per EPA Control Cost Manual
Electrical	0.01×B	$765,900.00	Per EPA Control Cost Manual
Piping	0.3×B	$22,977,000.00	Per EPA Control Cost Manual
Installation for ductwork	0.01×B	$765,900.00	Per EPA Control Cost Manual
Painting	0.01×B	$765,900.00	Per EPA Control Cost Manual
Direct Installation Cost	0.85×B	$65,101,500.00	Per EPA Control Cost Manual
Retrofit Factor	1.3		Per EPA Control Cost Manual
Direct Installation Costs Including Retrofit Factor		$84,631,950.00	
Site Preparation			As required, estimate
Buildings			As required, estimate
Total Direct Cost	1.30×B + SP + Bldg + Direct Costs	$161,221,950.00	Direct costs include foundation, handling, electrical, piping, ductwork, and painting
Indirect Costs (Installation)			
Engineering	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Construction and Field Expenses	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Contractor Fees	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Start-up	0.01×B	$765,900.00	Per EPA Control Cost Manual
Performance Test	0.01×B	$765,900.00	Per EPA Control Cost Manual
Contingencies	0.03×B	$2,297,700.00	Per EPA Control Cost Manual
Total Indirect Cost, IC	0.35×B	$26,806,500.00	Per EPA Control Cost Manual
Total Capital Investment (TCI)	TCI = DC + IC	$188,028,450.00	

Table A-3: Continued

Cost Item	Factor	Cost	Notes
Direct Annual Costs[1]			
Operating Labor			
Operator		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Supervisor		$3,346.59	15% of Operator
Operating Materials			
Lime required (tpy)		739	Lime required (tpy) =Lime Injection rate (lb/hr) * Operating Hours (hr/yr) / 2000 (lb/ton)
Limestone Cost ($/ton)		55.81	Current costs from Sunnyside's Limestone supplier
Limestone Cost ($/yr)		$41,235.33	Annual Cost ($/yr) = Limestone Cost ($/ton) × Annual Lime Required
Maintenance			
Maintenance Labor		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Maintenance Materials		$22,310.63	100% of Maintenance Labor
Utilities			
Rate		$49.45	($/MW) Total annual Busbar cost divided by MW produced from Sunnyside
Electricity		$6,485.54	Cost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of boiler
Direct Annual Cost		$117,999.34	
Indirect Annual Costs, IC			
Overhead	60% sum of operating labor, maintenance labor, and associated materials	$42,167.08	
Administrative Charges	= 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost.	$25,545.67	Where the TCI is estimated as $66600000
Property Taxes	1% of TCI	$1,880,284.50	Where the TCI is estimated as $66600000
Insurance	1% of TCI	$1,880,284.50	Where the TCI is estimated as $66600000
Indirect Annual Cost		$3,828,281.75	Sum of overhead, administrative, taxes, and insurance
Capital Recovery[2]		$0.09	$ Annually/$ Capital Cost
Annualized Capital Cost		$17,748,555.52	Capital Recovery * Total Capital Investment
Total Annual Cost (Dry Scrubber)		$21,694,836.60	$/year
Cost Effectiveness		$68,027.21	$/ton

[1] Capital recovery calculated based on the methodology provided in the EPA Control Cost Manual, Section 1 Chapter 2, Equation 2.8 and 2.8a on Page 2-22, where an interest rate of 7% is assumed.

[2] Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs

Interest	7.00%
Based on CFB Boiler Equipment Life (Life of the Unit)	20

Dry Scrubber Cost Analysis - Updated Minimum Cost - EPA Cost Control Manual

Table A-1: CDS/CFBS

Variable		Value	Units
Baseline SO_2 Emissions		471	tons/year
SO_2 Removal Efficiency		74%	Represented from RBLC Search search for Process Code 11.11 for Coal fired Utility and Large Industrial Size Boilers/Furnaces was pulled on April 19, 2022.
Total SO_2 Removed		318.91	tons/year (Calculated based on Removal Effciency)
Lime Injection Rate		184	lb/hr (Sargent & Lundy; ratiod to provide the appropriate lime injection rate)
Annual Operating Time		8031	hours/year

[1] Assumes control technology uptime of 92% for maintenance and unexpected boiler and control technology downtime. What is the capacity of the plant?

Table A-2: Dry Sorbent Injection Costs

Cost Item	Factor	Cost	Notes
Captial Costs[1]			
Equipment Cost	A	$66,600,000.00	EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, 1.2.1.2 Dry Flue Gas Desulfurization Systems, with a ratio applied to be consistent with the 74% control orginally estimated.
Retrofit Factor	1.3		Per EPA Control Cost Manual
Total Capital Investment (TCI)	TCI = A*1.3	$86,580,000.00	

Table A-3: Continued

Cost Item	Factor	Cost	Notes
Direct Annual Costs[1]			
Operating Labor			
Operator		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Supervisor		$3,346.59	15% of Operator
Operating Materials			
Lime required (tpy)		739	Lime required (tpy) = SO_2 emissions (tpy) × 3
Limestone Cost ($/ton)		55.81	Current costs from Sunnyside's Limestone supplier
Limestone Cost ($/yr)		$41,235.33	Annual Cost ($/yr) = Limestone Cost ($/ton) × Annual Lime Required
Maintenance			
Maintenance Labor		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Maintenance Materials		$22,310.63	100% of Maintenance Labor
Utilities			
Rate		$49.45	($/MW) Total annual Busbar cost divided by MW produced from Sunnyside
Electricity		$6,485.54	Cost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of boiler
Direct Annual Cost		$117,999.34	
Indirect Annual Costs, IC			
Overhead	60% sum of operating labor, maintenance labor, and associated materials	$42,167.08	
Administrative Charges	= 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost.	$25,545.67	Where the TCI is estimated as $66600000
Property Taxes	1% of TCI	$865,800.00	Where the TCI is estimated as $66600000
Insurance	1% of TCI	$865,800.00	Where the TCI is estimated as $66600000
Indirect Annual Cost		$1,799,312.75	Sum of overhead, administrative, taxes, and insurance
Capital Recovery[2]		$0.08	$ Annually/$ Capital Cost
Annualized Capital Cost		$6,977,170.82	Capital Recovery * Total Capital Investment
Total Annual Cost (Dry Scrubber)		$8,894,482.90	$/year
Cost Effectiveness		$27,889.90	$/ton

[1] Capital recovery calculated based on the methodology provided in the EPA Control Cost Manual, Section 1 Chapter 2, Equation 2.8 and 2.8a on Page 2-22, where an interest rate of 7% is assumed.

[2] Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs

Interest	7.00%
Based on CFB Boiler Equipment Life (Life of the Unit)	30

Dry Scrubber Cost Analysis - Updated Maximum Cost - EPA Cost Control Manual
Table A-1: CDS/CFBS

Variable		Value	Units
Baseline SO_2 Emissions		471	tons/year
SO_2 Removal Efficiency		74%	Represented from RBLC Search search for Process Code 11.11 for Coal fired Utility and Large Industrial Size Boilers/Furnaces was pulled on April 19, 2022.
Total SO_2 Removed		318.91	tons/year - Calculated based on Removal Efficiency
Lime Injection Rate		184	lb/hr (Sargent & Lundy)
Annual Operating Time		8031	hours/year

[1] Assumes control technology uptime of 92% for maintenance and unexpected boiler and control technology downtime.

Table A-2: Dry Sorbent Injection Costs

Cost Item	Factor	Cost	Notes
Captial Costs[1]			
Total Capital Investment (TCI)	TCI = DC + IC	$328,888,888.89	EPA Cost Control Manual, Section 5 SO2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, 1.2.1.2 Dry Flue Gas Desulfurization Systems, with a ratio applied to be consistent with the 74% control orginally estimated.

Table A-3: Continued

Cost Item	Factor	Cost	Notes
Direct Annual Costs[1]			
Operating Labor			
Operator		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Supervisor		$3,346.59	15% of Operator
Operating Materials			
Lime required (tpy)		739	Lime required (tpy) = SO_2 emissions (tpy) × 3
Limestone Cost ($/ton)		55.81	Current costs from Sunnyside's Limestone supplier
Limestone Cost ($/yr)		$41,235.33	Annual Cost ($/yr) = Limestone Cost ($/ton) × Annual Lime Required
Maintenance			
Maintenance Labor		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Maintenance Materials		$22,310.63	100% of Maintenance Labor
Utilities			
Rate		$49.45	($/MW) Total annual Busbar cost divided by MW produced from Sunnyside
Electricity		$6,485.54	Cost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of boiler
Direct Annual Cost		$117,999.34	
Indirect Annual Costs, IC			
Overhead	60% sum of operating labor, maintenance labor, and associated materials	$42,167.08	
Administrative Charges	= 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost.	$25,545.67	Where the TCI is estimated as $400000000
Property Taxes	1% of TCI	$3,288,888.89	Where the TCI is estimated as $400000000
Insurance	1% of TCI	$3,288,888.89	Where the TCI is estimated as $400000000
Indirect Annual Cost		$6,645,490.52	Sum of overhead, administrative, taxes, and insurance
Capital Recovery[2]		$0.09	$ Annually/$ Capital Cost
Annualized Capital Cost		$31,044,784.47	Capital Recovery * Total Capital Investment
Total Annual Cost (Dry Scrubber)		$37,808,274.33	$/year
Cost Effectiveness		$118,553.16	$/ton

[1] Capital recovery calculated based on the methodology provided in the EPA Control Cost Manual, Section 1 Chapter 2, Equation 2.8 and 2.8a on Page 2-22, where an interest rate of 7% is assumed.

[2] Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs

Interest	7.00%
Based on CFB Boiler Equipment Life (Life of the Unit)	20

ATTACHMENT B - FIRM-SPECIFIC INTEREST RATE – FOUR FACTOR ANALYSIS

Letter dated: March 15, 2022 to UDAQ from Sunnyside Cogeneration Associates.

Trinity Consultants
4525 Wasatch Blvd, Ste 200, Salt Lake City, UT 84124 / P 801.272.3000 / F 801.272.3040 / **trinityconsultants.com**

March 14, 2022

Ms. Chelsea Cancino
Environmental Scientist
Utah Division of Air Quality
195 N 1950 W
Salt Lake City, UT 84116
ccancino@utah.gov

RE: Response to UDAQ questions on Sunnyside Cogeneration Associates Four Factor Analysis

Dear Ms. Cancino:

Sunnyside Cogeneration Associates (Sunnyside) and Trinity Consultants (Trinity) have prepared this letter in response to comments made by Federal Land Managers (FLMs) to Utah Division of Air Quality's (UDAQ's) Four-Factor Analysis Evaluation. Questions centered around the use of a 7% interest rate and further discussion of this interest rate is provided in this memorandum.

If you have further questions about these responses, please reach out to Brian Mensinger at Trinity (801-272-3040/bmensinger@trinityconsultants.com) or Rusty Netz at Sunnyside (rusnetz@hotmail.com) for further information or clarification.

DISCUSSION OF INTEREST RATE

The selection of a firm-specific interest rate is critical to preparing an accurate control cost estimate for use in a four factor analysis. FLMs provided additional comments to UDAQ stating preference for the use of the current bank prime rate of 3.25%. The Sunnyside dry sorbent cost analysis assumed a 7% interest rate and a 20-year life in amortizing the capital cost of this control system. Additionally, a similar interest rate was used for for SCR and SNCR cost analyses.

EPA Guidance

EPA's Air Pollution Control Cost Manual (Cost Manual) states: "When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[1] EPA further states: "For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified."

The bank prime rate is a well-established lending rate, in this case established on a national basis. This rate is generally considered the lowest possible lending rate and is updated annually. For this analysis, which evaluates equipment costs that may take place more than 5 years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The cost manual cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available.

[1] EPA Air Pollution Control Cost Manual (EPA/452/B-02-001), Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, s. 2.5.2; November 2017

From 2000 to 2020, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.79% over that period.[2] Interest rates have been increasing recently with concerns that this trend will continue. The Cost Manual also cautions that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[3] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

Site Specific Information

Sunnyside solicited an appraisal report in January of 2021 which documented the company's Weighted Average Cost of Capital (WACC). WACC is defined as the "the opportunity cost of all capital invested in an enterprise" on a weighted average basis.[4] WACC generally accounts for a variety of company specific or project specific financial assumptions including:

- Fraction of the cost of capital financed by debt;
- Cost of debt;
- Tax rate;
- Fraction of the cost of capital financed by equity; and
- Cost of equity.[5]

In general a higher WACC is representative of a higher financial risk for the company or financing institution. The appraisal solicited by Sunnyside reported a WACC of 12.46% after adjustment for property taxes.[6] Table 1 compares this WACC to standard industry values.

Table 1. Comparison of WACC Values[7]

Industrial Sector	WACC
Total Market	5.14%
Coal and Related Energy	4.57%
Utility (General)	3.87%
Sunnyside	12.46%

Table 1 demonstrates that the WACC for Sunnyside is significantly higher than the market on average and similar industry sectors. The Sunnyside Plant was originally commissioned in the early 1990s. The age of the plant and anticipated additional operating years both contribute to a higher investment risk and subsequently to the increased WACC.

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[2] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020.
https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020

[3] EPA Air Pollution Control Cost Manual (EPA/452/B-02-001), Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, s. 2.5.2; November 2017

[4] New York University, Stern School of Business "The Weighted Average Cost of Capital"
https://pages.stern.nyu.edu/~igiddy/articles/wacc_tutorial.pdf

[5] Pennsylvania State University "Weighted Average Cost of Capital" https://www.e-education.psu.edu/eme801/node/585

[6] Reviewing experts included the following firms: Bodington & Co, Sterling Energy, and Energy Ventures Analysis.

[7] New York University, Stern School of Business published values, dated January 2022;
people.stern.nyu.edu/adamodar/New_Home_Page/datafile/wacc.htm

WACC cannot be substituted for nominal interest rate, because these two values are used for two fundamentally different purposes. WACC allows a company to quantify depreciation, or discount rate, on a whole cost basis while nominal interest rate represents the additional cost required by a financial institution for the acquisition of a loan. However, both values require businesses and/or financial institutions to consider the financing structure of the company and the risk inherent in the investment being made. Thus, the increased WACC supports the use of a nominal interest rate higher than the current bank prime rate.

Since the actual nominal interest rate for a project of this type is not readily available to Sunnyside, additional resources were reviewed to determine appropriate nominal interest rates for this industry sector and project type. One such resource was the Office of Management and Budget (OMB). For economic evaluations of the impact of federal regulations, the OMB uses an interest rate of 7%.

> *"As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."*[8]

Furthermore, the Texas Commission on Environmental Quality (TCEQ) stated in their 2021 Regional Haze State Implementation Plan revision that they had assumed a 10% interest rate for estimating annualized capital costs for EGUs and for non-EGUs, where appropriate.[9] The TCEQ assumed an interest rate of 10% for all sources and units evaluated because it was assumed that regulated entities would be able to secure, on average, this rate when attempting to finance capital investments associated with air pollution control devices and abatement equipment. It is expected that some sources, depending on their financial institution and method of financing, would have interest rates higher or lower than 10%, but the TCEQ assumed that a constant 10% interest rate would be a reasonable 'mid-point' to use across all source categories.

Additionally, EPA used a capital recovery factor (CRF) of 0.0806, which corresponds to 30 years at 7% interest, in its April 2015 Federal Implementation Plan (FIP) for Arkansas.[10] Finally, a nominal interest rate of 7% has been referenced in EPA's Cost Manual and has been commonly relied upon for control technology analyses for several decades, including periods when the bank prime rate was exactly the same as it is now (3.25%).[11]

Based on the information documented in this memorandum, a nominal interest rate of 7% was chosen to perform the cost analysis for Sunnyside's four factor analysis. This rate was supported by a variety of institutions and most closely matched the financial indicators known by Sunnyside.

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[8] OMB Circular A-4, https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/

[9] TCEQ 2021 Regional Haze SIP Revision, Appendix B, Analysis of Control Strategies to Establish Reasonable Progress Goals, published October 2020 (Project Number 2019-112-SIP-NR)

[10] 80 FR 18944 *Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, Proposed rule* (April 8, 2015) Docket No. EPA–R06–OAR–2015–0189, Appendix A. *Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO2 Cost TSD).*

[11] https://www.bankrate.com/rates/interest-rates/prime-rate.aspx