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December 16, 2013

Mr. Thomas H. Diggs
Associate Director, Air Programs Branch
U.S. Environmental Protection Agency
Mail Code 6PD-R
1445 Ross Avenue
Suite 1200
Dallas, TX 75202-2733

Via Overnight Courier and Electronic Mail

Re: GHG PSD Permit Application Completeness Determination
Tenaska Brownsville Generating Station

Dear Mr. Diggs:

Tenaska Brownsville Partners, LLC (Tenaska) herein provides responses to your referenced letter dated November 27, 2013 regarding the Greenhouse Gas Prevention of Significant Deterioration permit application for the proposed Tenaska Brownsville Generating Station. We have provided responses below following the sequence in your letter.

1. **On page 11 of the permit application, Tenaska proposes the installation of a fuel gas heater. Please provide supplemental data that discusses the rationale, including any plant efficiency gains, for utilizing the proposed natural gas fuel heater. What are the upstream and downstream emission effects associated with the use of fuel gas heater?**

   We note first that current facility design calls for an electric-powered fuel gas heater instead of the gas-fueled design included in the application, due to anticipated very low utilization of the unit. Applicable revised portions of the application will be submitted accordingly.

   The proposed fuel gas heater is included for the purpose of meeting the combustion turbine's fuel gas specification regarding condensable liquids. This fuel gas heater is included for fuel gas dew point purposes, not plant efficiency purposes. The fuel gas as fed to the nozzles of the combustion system must not contain any constituents in the liquid state. The fuel gas constituent having the highest saturation temperature must have a minimum amount of superheat.

   The fuel gas dew point heater will only operate during startup conditions when the fuel gas performance heater is not yet operational, and the minimum amount of superheat has not yet been satisfied. The fuel gas performance heater is an additional heater that will be included in the cycle and is heated by feedwater from the steam cycle, not electric or gas-fired.

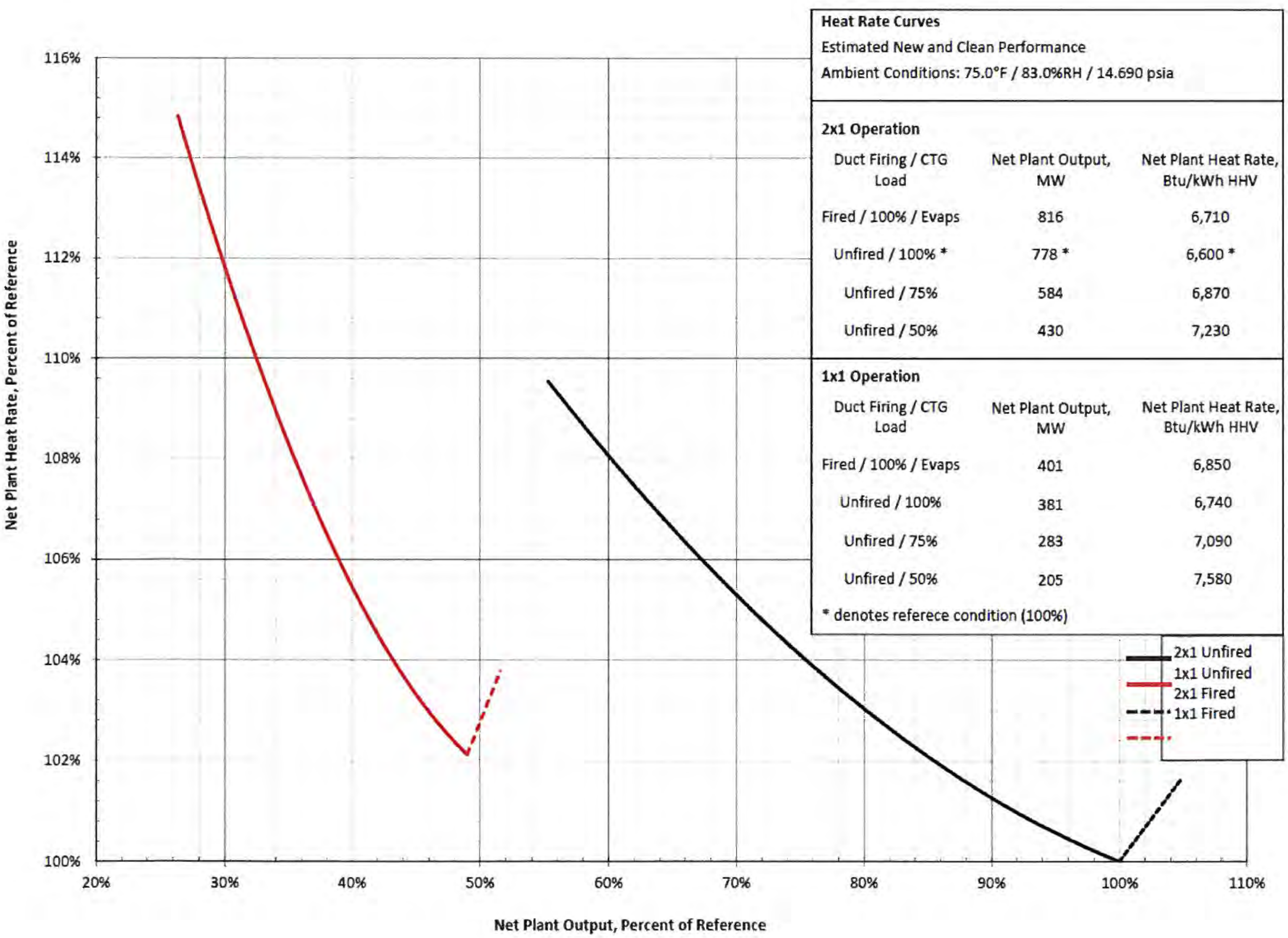
   There will be no upstream or downstream emission effects associated with the proposed electric dew point heater.

2. **On page 30 of the permit application in Table 10.1, Tenaska has proposed annual tons per year GHG BACT emission limits for the fuel gas heater and auxiliary boiler. Please provide an output-based BACT emission limit, or a combination of an output- and input-based limit, or an equipment efficiency-based limit of transferring heat. If a numerical emission limit or an efficiency-based limit is not feasible, please provide a rationale to support this determination. Also, please provide a proposed compliance methodology to support an output-based BACT numerical limit.**

   Tenaska proposes an efficiency-based BACT limit for the auxiliary boiler of 82% HHV. As stated in the response above, the proposed fuel gas/dew point heater will be electric, not gas-fired. Therefore, no BACT limit will be required for that unit.

3. **Please provide the load efficiency curves for the proposed combustion turbine model.**

   Please see the "new and clean" plant performance estimates and heat rate curves below.




**Heat Rate Curves**
Estimated New and Clean Performance
Ambient Conditions: 75.0°F / 83.0%RH / 14.690 psia

| Duct Firing / CTG Load | Net Plant Output, MW | Net Plant Heat Rate, Btu/kWh HHV |
|---|---|---|
| **2x1 Operation** | | |
| Fired / 100% / Evaps | 816 | 6,710 |
| Unfired / 100% * | 778 * | 6,600 * |
| Unfired / 75% | 584 | 6,870 |
| Unfired / 50% | 430 | 7,230 |
| **1x1 Operation** | | |
| Fired / 100% / Evaps | 401 | 6,850 |
| Unfired / 100% | 381 | 6,740 |
| Unfired / 75% | 283 | 7,090 |
| Unfired / 50% | 205 | 7,580 |

* denotes referece condition (100%)

**4. On page 42 of the permit application the application proposes a 3.3% design margin, a 6% reasonable degradation margin, and a 3% degradation margin for the auxiliary equipment. Please provide a basis and supplemental manufacturer's documentation to substantiate these proposed margins.**

$CO_2$ emission regulations and guarantees are a new requirement for the energy industry Original Equipment Manufacturers (OEMs) and Engineering, Procurement, and Construction (EPC) Contractors and, as such, adds risk to their commercial offerings. In order to manage this risk, they are likely to include margined guarantees. A margin above the new and clean design net base heat rate includes the following three components, each described more fully:

- Design Margin
- Power Island Performance Degradation
- Auxiliary Equipment Degradation

Design Margin

Tenaska elected to use a 3.3% design margin based on the following considerations:

- The detailed project scope is not fully defined. A number of design elements are not fully decided until detailed engineering, including determination of vendor and geometry of the heat recovery steam generator, cooling tower fill media type and dimensions, condenser surface area, balance of plant system details and performance, piping pressure drops, etc., and their resultant effect on performance. Additionally, there is risk that the as constructed and installed equipment may not fully achieve the design performance.

- $CO_2$ emission regulations and requirements are new to the industry as well as for the OEMs/EPCs. Margin is added to manage risks associated with unverified requirements and potential for variations in plant operating characteristics.

- Measurement uncertainty. Every measurement is the combination of the true value plus measurement error. Thus, there is inherent uncertainty in the measurement. This uncertainty has two parts: (1) systematic error (also known as bias or fixed error) which is a function of the particular measurement device type/vendor and installation and (2) random or statistical error which results from the scatter of repeated measurements using the same instrumentation. The definitions for test uncertainty can be found in ASME PTC 19.1.

- Each combustion turbine is unique. During commissioning, the combustion turbine OEM observes the combustion dynamics and tunes the unit performance by adjusting various control parameters, including the firing curve, emissions, inlet guide vane angles, air-fuel ratios, flame stability, dynamic combustor pressure pulsations, and other parameters. Depending on the turbine, unit output and/or heat rate may need to be compromised for the purpose of tuning for emission compliance.

Given the typical value of measurement uncertainty of 1.0-1.5%, plus the other un-quantified issues described above, Tenaska elected to use a 3.3% margin.

Power Island Performance Degradation

A 6% performance degradation margin for normal wear and tear over the life of the combustions turbines, HRSGs, and steam turbine generator was included and is based on the following factors:

- Tenaska's experience with their operating fleet of combined cycle electric generating facilities
- MHI's proprietary projection of long term combustion turbine performance degradation
- ASME PTC 6 Report's guidance for estimating steam turbine degradation
- HRSG OEM guidance for estimating HRSG performance degradation

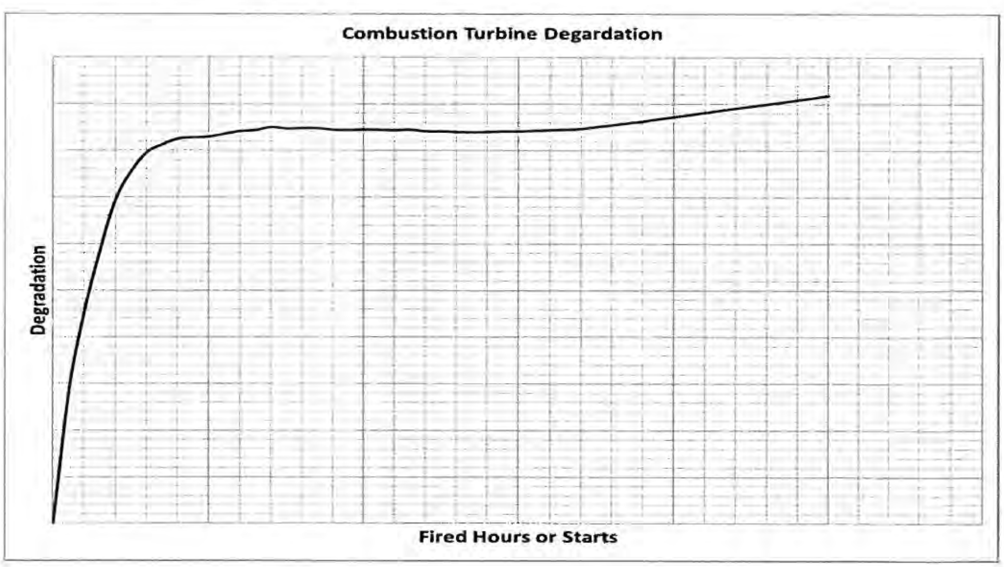
Degradation can be grouped into two types: non-recoverable and recoverable. The contributions from these two types and the time period over which they occur are a function of the plant operating profile.

Combustion Turbine Performance Degradation

Even under the best possible operating conditions, the performance of a combustion turbine is subjected to deterioration due to compressor fouling and corrosion, inlet filter clogging, thermal fatigue and oxidization of hot-gas path components such as combustion liners and turbine blades. Collectively, these mechanisms reduce the electrical output and efficiency of combustion turbines. The heat rate increase causes a corresponding increase in the $CO_2$ emission rate per unit of output.

The contributions of non-recoverable and recoverable degradation is a function of the number of fired hours and number of starts on the combustion turbines as well as trips, run backs and other operating realities as dictated by market forces. The timing of planned maintenance (e.g. hot gas path inspection, major, etc.) is a function of operating hours, starts, load rejections, and other factors.

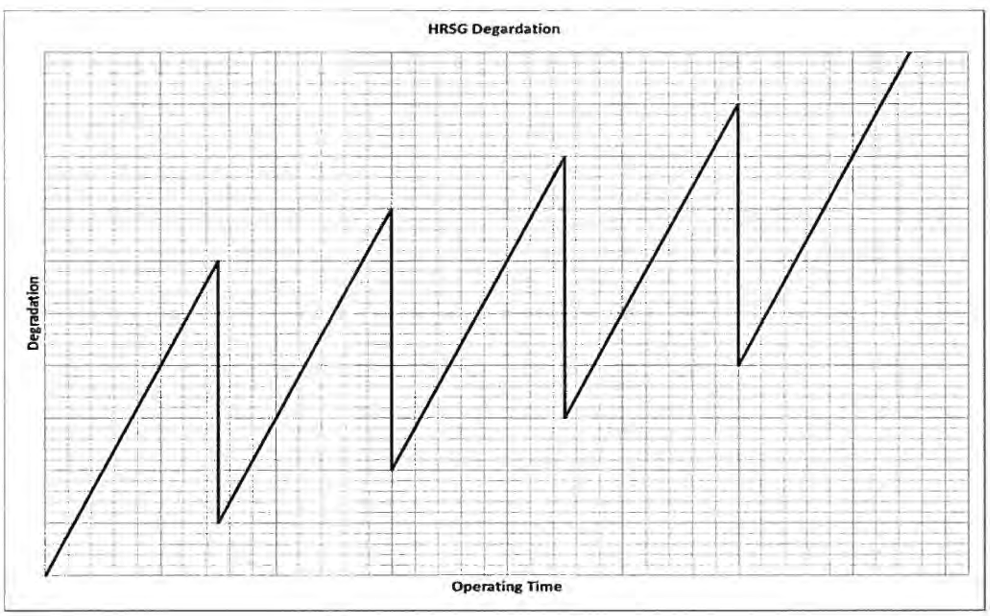
Non-recoverable degradation occurs and continues throughout the operating life of the combustion turbine. As shown below, the trend generally consists of relatively rapid initial heat rate degradation for the first few thousand operating hours/starts which then flattens to a long term degradation rate. The long term impact is a 2.5 to 3.0% increase in heat rate over new and clean performance for the initial major maintenance cycle.



Recoverable degradation is that which may be recovered through compressor washes, the performance of major maintenance, instrument calibration, etc. which accumulates over the major maintenance cycle. The rate of change is minimized by performing compressor washes and practicing good overall plant maintenance. When an off-line wash, major maintenance, instrument calibration, etc. are performed, the unit heat rate should return to the new and clean heat rate plus the non-recoverable degradation.

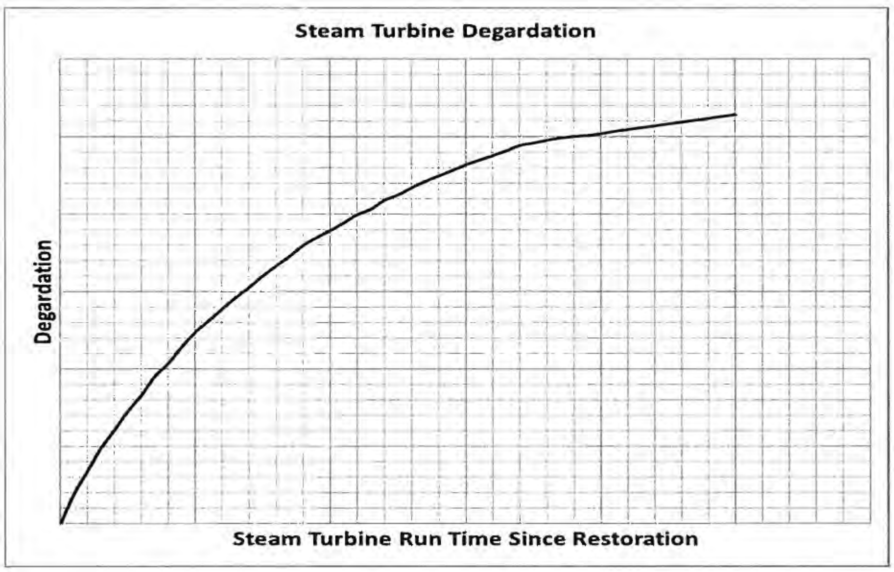
HRSG Performance Degradation

Continuous or intermittent operating of an HRSG behind a combustion turbine will result in fouling of heat transfer surface area (finned surface and/or outer tube surface). HRSG performance degradation is in the form of reduced HRSG steam production, steam temperature, steam pressure, or a combination thereof. Plant heat rate increase is manifested through decreased steam turbine performance, resulting in an increase in the specific $CO_2$ emission rate. Degradation occurs and continues throughout the operating life of the HRSG. Based on estimated non-recoverable degradation data from the OEM's, HRSG degradation is estimated to be 0.5 to 1.5% over the course of the initial combustion turbine major maintenance cycle. The general trend of HRSG degradation is depicted below.



Steam Turbine Performance Degradation

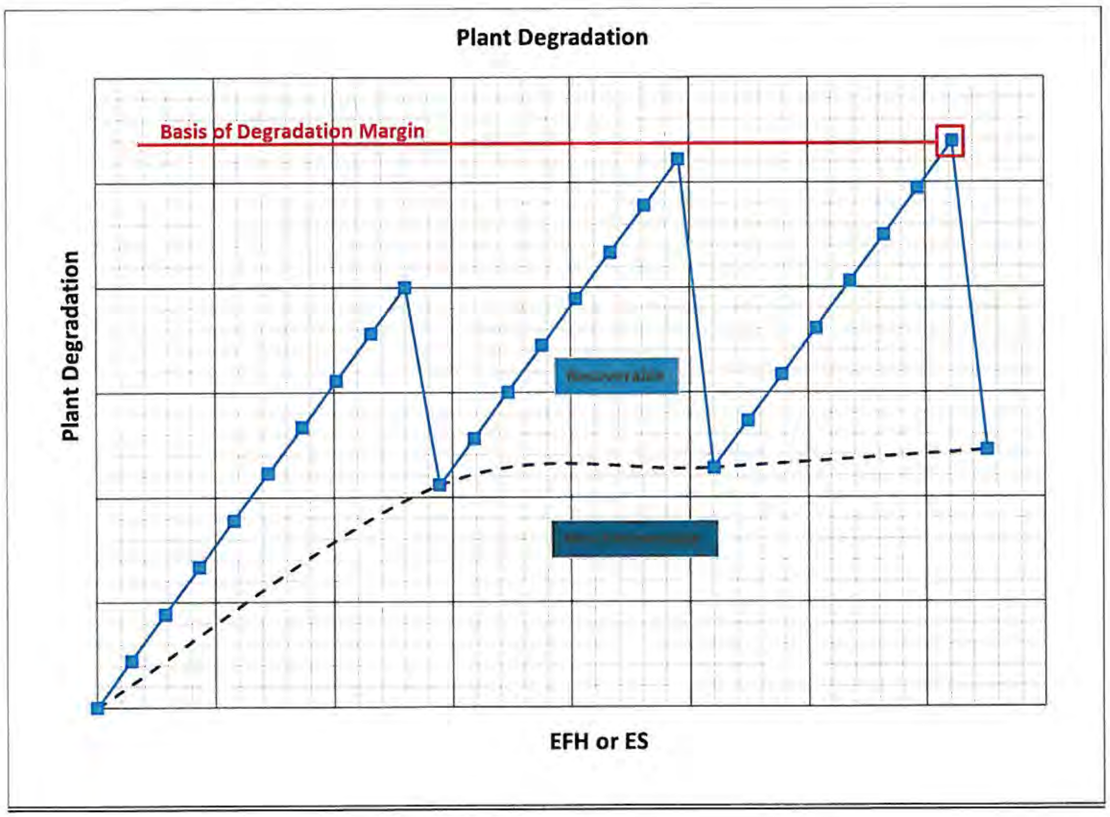
ASME's PTC 6 Report provides guidance on estimating steam turbine degradation based on industry experience. The guidance was developed from the results of enthalpy drop tests run periodically on a number of turbines of various sizes. Using this guidance, steam turbine degradation ranges from approximately 2 to 3% over one major maintenance cycle, which is projected to be coincident with a combustion turbine major maintenance cycle. As noted in the PTC 6 Report, its guidance is based upon good operating practices and no detrimental incidences. Examples of detrimental incidents per the PTC 6 Report are: turbine water induction incidents, unusual shaft vibration, abnormal conductivity in the condenser hotwell, excessive boiler water silica, large excursions in throttle and reheat temperatures, and other incidents.



## Total Plant Thermal Efficiency Degradation

Total plant degradation (non-recoverable plus recoverable) appears as a saw-tooth type curve, as generally shown below. As previously mentioned, the individual contributions from recoverable and non-recoverable types of degradation are dependent on the run profile and Tenaska cannot definitively predict the future market conditions for the life of the plant and there is significant uncertainty in whether the performance will be recovered in practice.

Tenaska modeled a matrix of plausible run profiles (with various combinations of fired hours, starts and capacity factors) to compute the degradation profile. Tenaska selected the highest heat rate for the worst year from the worst run profile (the highest peak of the saw tooth) curve. The plant thermal efficiency degradation was nominally 6% above new and clean performance.




## Auxiliary Equipment Degradation

Tenaska elected to use a reasonable performance degradation margin of 3% based on normal wear and tear on auxiliary plant equipment, including boiler feedwater, condensate and circulating water pump degradation, condenser tube fouling, condenser air in leakage, condenser air ejector degradation, cooling tower fouling and other balance of plant system degradation over the life of the plant. The individual contributions from these types of degradation are difficult to quantify and are also dependent on the plant's run profile.

It should be noted that the following PSD GHG permits issued by USEPA Region 6 contain $CO_2$ BACT limits based upon these same margin adjustments:

- Lower Colorado River Authority Thomas Ferguson Power Plant
- Calpine Deer Park Energy Center
- Calpine Channel Energy Center
- La Paloma Energy Center

5. **On page 32 of the permit application, it is stated that Tenaska's BACT analysis of carbon capture sequestration (CCS) is based on the capture of 85 to 90 percent of the $CO_2$ emitted from the plant using the Flour Econamine FG Plus (amine-based) technology. Please provide the supplemental documentation and calculations to support the cost estimates presented in Table C-2. Please provide the site-specific facility data to evaluate and eliminate CCS. This includes detailed information on the necessary equipment for capture, transportation, and storage. Please provide the separate the costs for construction, annual operation, and maintenance for a CCS system.**

The Fluor Econamine FG Plus$^{SM}$ technology discussed on Page 32 of the permit application corresponds to the Tenaska Trailblazer Energy Center, a supercritical pulverized coal plant once proposed to be located in Sweetwater, Texas but which has since been cancelled due to unfavorable economics. Tenaska is not proposing the use of this technology for the Brownsville Generating Station, a natural gas combined cycle plant. The Trailblazer project details were included in the Brownsville permit application as part of the identification of all currently available control technologies.

The CCS costs for the proposed Brownsville project are calculated based on a 90% capture rate, published data, and site-specific information where available. Site-specific data used include uncontrolled $CO_2$ emissions and pipeline length, the latter of which is based upon the distance to the nearest EOR site (approximately 106 miles). The CCS costs presented in Table C-2 are estimated using the following documents, as noted in the footnotes:

- $CO_2$ Capture and Compression System: *Report of the Interagency Task Force on Carbon Capture and Storage* (August, 2010), Page A-14. As noted in Section A-3 of this report, the cost estimate includes construction, annual operation, and maintenance of the capture and compression system. Therefore, separate costs for each of these components are not estimated and a single aggregate cost estimate is provided.

- $CO_2$ Transport Facilities: *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs* (March 2010). The detailed cost estimation including the cost of pipeline construction, operation and maintenance is included in Table C-1.

- $CO_2$ Storage System: *Report of the Interagency Task Force on Carbon Capture and Storage* (August, 2010), page 44. As noted in footnote 53 of this report, the cost estimate includes capital and operational costs. Therefore, separate costs for each of these components are not estimated and a single aggregate cost estimate is provided.

Copies of the *Report of the Interagency Task Force on Carbon Capture and Storage* and *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs* are included in the e-mailed response (due to file size) for your reference.

We trust these responses satisfactorily address your comments. Please let me know if you have any questions or require additional information. We look forward to a completeness determination and issuance of the draft permit.

Sincerely,

**TENASKA BROWNSVILLE PARTNERS, LLC**
a Delaware limited liability company
By: Tenaska Brownsville I, LLC, Its Manager

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