CONFIDENTIAL

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To: Susannah Churchill (CPUC – Energy Division)
From: Joe Lawlor (PG&E)

Hi Susannah – below are the responses to your questions regarding the DTE Stockton contract.

Questions

1a) What is the maximum and minimum allowable prices under the contract, both TOD-adjusted and non-TOD adjusted, assuming fuel prices increase but don't exceed the maximum allowable of $75/ton (BDT, or Bone Dry Ton)?

Answer: Per Article 4.1 of the power purchase agreement (PPA), the non-TOD price under the contract is $129.15/MWh. The maximum and minimum price for any single hour would then be derived by considering the TOD adjustments for that hour. In addition to that, if fuel prices rise to $75/BDT in 2018, PG&E would share 50% of the amount over $50/BDT (or a maximum of $12.50/MWh). While I've assumed $75/BDT based on the Energy Division's request, its worth pointing out that if the price went to $100 BDT and DTE didn't request a reopener, the contract would still continue but PG&E would pay a maximum of $12.50 (i.e. not a greater amount based on 50%) under Article 4.8(c) and DTE would pay the remaining increase. The below table calculates the maximum and minimum prices in any hour in 2018 assuming fuel prices at both Woodland and DTE Stockton are at $75/BDT. For a true minimum price calculation, the case of low fuel prices where DTE Stockton pays PG&E a fuel adjustment should also be considered; so that scenario has been added as well.

Fuel Price Scenarios - 2018 Year		**Units**	**Function:**	**Contract Term**
Contract Price (Non-TOD Adjusted)	129.15	$/MWh	A	Article 4.1
TOD Adjusted Prices:				
Max TOD Factor	2.01		B	Article 4.2
Min TOD Factor	0.63		C	Article 4.2
Max Price (TOD Adjusted)	259.59	$/MWh	D=A x B	Calculation
Min Price (TOD Adjusted)	81.36	$/MWh	E=A x C	Calculation
Assuming Fuel Prices in 2018 go to (for both Woodland & Stockton)	75.00	$/BDT	F	Assumption
Maximum Fuel Price for 2018	50.00	$/BDT	G	PPA Appendix XV

Fuel Cost in Excess of Maximum	25.00	$/BDT	H=F-G	Calculation
PG&E's share of fuel cost in excess of maximum	50%		I	Article 4.8
Fuel Costs allocated to PG&E	12.50	$/BDT	J=H x I	Calculation
BDT conversion to $/MWh (1 $/BDT= 1$/MWh)	12.50	$/MWh	K	Definition of BDT
Maximum TOD Contract Price Including Maximum Fuel Adj	**272.09**	**$/MWh**	**L=D+K**	**Calculation**
Non-TOD Adjusted Price, Including Maximum Fuel Adjustment	**141.65**	**$/MWh**	**M=A+K**	**Calculation**
Minimum TOD Contract Price Including Maximum Fuel Adj	**93.86**	**$/MWh**	**N=E+K**	**Calculation**

Minimum TOD Contract Price, if Fuel prices drop to $10/BDT or less in 2018:

Assuming Fuel Prices in 2018 drop to:	10.00	$/BDT	O	Assumption
Minimum Fuel Price for 2018	35.00	$/BDT	P	PPA Appendix XV
Fuel Cost Below Minimum	-25.00	$/BDT	Q=O-P	Calculation
PG&E's share of fuel cost in excess of maximum	50%		R	Article 4.8
Fuel Costs allocated to PG&E	-12.50	$/BDT	S=Q x R	Calculation
Minimum TOD Contract Price Including Fuel Adj Payment to Buyer for Low prices	**68.86**		**T=E+S**	**Calculation**

1b) Please confirm that prices listed on Page D-26 of the AL ($137.09/MWh or $141.39 TOD-adjusted) are the maximum prices, and state the minimum prices, both TOD-adjusted and non-TOD adjusted

Answer: The prices on D-26 are the levelized price (in the case of the $137.09/MWh) and TOD-adjusted levelized price (in the case of the $141.39/MWh) over the entire contract term. These amounts include the years from 2013 through 2017 at $129.15/MWh and later add the maximum $12.50/MWh fuel price adder starting in 2018. As such, these are not the minimum and maximum in any one hour, but an average that accounts for all hours across all years and assuming a base-load generation profile. Said another way, the model calculates the $137.09/MWh by using a price of $129.15 multiplied by annual MWh generation, throughout the term, with $12.50/MWh added starting in 2018. These numbers for all years are summed and then divided by the total discounted generation across the years resulting in a price of $137.09/MWh. If the price is also multiplied by the TOD factors, the resulting levelized price is then the TOD-adjusted price of $141.39.

The maximum and minimum price, both TOD and non-TOD adjusted were provided in response to question 1a.

Questions 1c) The IE report (page A10) makes reference to the price being allowed to rise by $12.50/MWh, please confirm:

Answer: PG&E Confirms. Without PG&E's consent, the price can not rise greater than $12.50/MWh pursuant to Article 4.8(c).

Question 2) Re. GHG change of law provision:

2a) would any costs resulting from AB 32 implementation qualify as a change of law under this provision, even though AB 32 was enacted years ago, because implementation is not yet complete? Please explain why the developer should not be responsible for the risk of GHG emissions costs associated with their project's generation as anticipated under AB 32, if that is the case.

Answer: The PPA was negotiated and priced by the Seller as if the facility was exempt from GHG taxes. DTE did not anticipate Green House Gas costs under current (AB32) or future legislature related to the use of biomass, and in particular urban wood waste, as a fuel to generate renewable electricity. DTE's comfort came from precedents which have declared biomass combustion exempt from greenhouse gas regulations on the basis that it is carbon neutral. This finding has been declared by such regulatory bodies as the Environmental Protection Agency, the California Air Resource Board (Preliminary Draft Regulation for a California Cap-and-Trade Program - 11/24/09) and the California Public Utility Commission (D.07-01-039 - 1/25/07). Further bolstering their confidence is a study prepared by Gregg Morris, PhD in May 2008 for the Pacific Institute entitled "Bioenergy and Greenhouse Gases" that concludes that biomass power generation has roughly twice the GHG benefit as other forms of renewable energy because it both displaces fossil fuel usage and avoids alternative disposal fates for biomass that have greater GHG emissions. However, even with a large amount of confidence, they refused to accept the potential risk of future GHG legislation under the prices offered since if GHG costs later came into effect it could make the plant unviable under the offered pricing. Therefore, PG&E negotiated the GHG term prudently to allow flexibility depending on the potential outcomes. Under the negotiated GHG term, there are three potential outcomes: a) the parties can agree to some cost sharing, b) either party may agree to take 100% of the cost; or c) the contract may terminate.

The alternative to negotiating a term such as this would have been for PG&E to refuse to negotiate any GHG cost sharing and the Seller would then have had to raise its price under the PPA to cover its view of the GHG uncertainty, if such a structure were to even be acceptable to the Seller. PG&E felt the cost of GHG mitigation was unlikely to be large for this type of resource, thus ratepayers would be better off without requiring the Seller to price GHG risk exposure into the contract. In addition, if GHG costs are implemented, PG&E can refuse to accept the cost and the contract will terminate or if the costs appear reasonable when compared to other market options for renewable energy at the time, PG&E can accept the GHG cost and the contract will continue.

2b) 10.1(c) in the PPA seems to say that if federal GHG legislation hasn't passed by Jan 2011 (very likely), the Seller can terminate the agreement. Please explain.

Answer: January 2011 is approximately when the Seller believed it would have to start spending significantly greater amounts of capital to get the project built and online in a timely manner. As such, the Seller insisted on an opportunity to assess the GHG legislation at that time to prevent a situation where draft legislation had changed and potential significant costs loomed, but a change in law hadn't yet occurred. In this case, the Seller needed a termination option to prevent it from having to develop a plant where PG&E would reject the GHG change in law after the legislation was adopted.

2c) Would PG&E submit an amended AL at CPUC (or otherwise request CPUC approval) if prices change pursuant to this section of the contract? Please point to where in the AL you note this.

Answer: PG&E does not envision submitting an amended AL if prices change pursuant to that term of the contract. A price change would be considered as a part of the prudent administration of the contract and likely be implemented through an amendment to the contract, which can be reviewed through ERRA. However, depending on the size of a potential price change, PG&E may consider submitting an amended AL for approval.

2d) Have other PG&E RPS contracts included a similar provision? Please discuss.

Answer: Solar and wind counterparties generally do not believe they have a GHG exposure so they have not sought a specific GHG term. Many counterparties seek a general change in law provision, a compliance cost cap, or some other way to limit their exposure to a particular risk – such as the fuel cost adjustment or GHG change in law here. Further, in some contracts PG&E assumes the GHG compliance cost immediately since certain developers failed to reasonably price the exposure in their offers; this was the case in all contracts for new generation executed through the LTRFO.

Question 3) What are the water needs and planned supply for the project?

Answer: The Port of Stockton District Energy Facility (POSDEF, or the name of the existing coal QF that will be converted to Biomass and called DTE Stockton) currently utilizes the City of Stockton's municipal water system, and sanitary and storm sewer systems located within the Port of Stockton. The anticipated conversion of the facility from coal to biomass fuel will not increase the amount of water required for operations as DTE will continue to use much of the existing equipment, such as cooling towers, boiler feed pumps, etc. Initial discussions with representatives of the City of Stockton's Municipal Utility Department agreed that a change in fuel would not lead to any additional water or sewer requirements. Upon initial review, the Municipal Utility

Department did not believe any restrictions or additional requirements would be made of the facility.

Currently, the facility operates under the National Pollution Discharge Elimination System (NPDES) general permit for storm water discharges associated with industrial activities. DTE will continue to implement the Storm Water Pollution Prevention Plan (SWPP) and all the best management practices which have been developed to control runoff of sediment on the site.

POSDEF holds a permit from the City of Stockton for the discharge of up to 4.5 million gallons of effluent into the sanitary sewer per month. The discharge permit requires extensive monitoring and reporting. DTE will continue to conduct the required monitoring, reporting and record maintenance.

Question 4) Page D-7 of the AL states that DTE has to convert the existing grandfathered QF connection to a new CAISO LGIA and install CAISO revenue quality meters. Please describe the milestones that will be required for each, and the list the projected dates for reaching each milestone.

Answer: POSDEF is an operational facility with a Qualified Facility Interconnection Agreement in effect for the same plant size as will be the size of the plant after conversion to biomass. DTE plans to convert the existing agreement into a CAISO Large Generator Interconnect Agreement (LGIA). DTE is familiar with the required CAISO LGIA interconnection conversion process since it recently completed the same process for upgrading a QF interconnection/metering for its Woodland facility, which was required by a new power purchase agreement too. The process consists of executing a new CAISO LGIA agreement and installing new CAISO approved revenue meters and telemetry. Since the facility is currently operational, a transmission study usually is not required. DTE's Woodland Biomass was able to accomplish these tasks within 9 months.

Since there is an existing interconnection in effect for the appropriate size, a separate milestone for interconnection was not included as a part of Appendix III. DTE plans to initiate discussions regarding the new interconnect agreement with CAISO by July 2011, allowing 24 months for execution of agreements and installation and testing of new equipment before the required online date of June 30, 2013.

5) How much fuel is the project estimated to use per year?

DTE is assuming the output of the plant will be approximately 45 MWs for 8760 hours a year at a 90% capacity factor (or 355,000 MWh/year); operations at that level would require approximately 355,000 BDTs of biomass fuel.