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DYNEGY

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Via E-Mail with Hard Copy by U.S. Mail
California Energy Commission
Dockets Office, MS-4
Re: Docket No. # 09-IEP-1O
1516 Ninth Street
Sacramento, CA 95814-5512
docket@energy.state.ca.us

Re: 2009 IEPR – OTC; Docket No. 09-IEP-1O
Comments on CEC Workshop regarding Implications on Electric Reliability of Proposals for Mitigation of Once-Through Cooling of Existing Electric Generating Facilities

Dear Sir or Madam:

Dynegy Inc. (Dynegy) submits these comments in follow-up to the California Energy Commission (CEC) 2009 Integrated Energy Policy Report Committee's July 28, 2009 workshop regarding implications on electric reliability of proposals for mitigation of once-through cooling (OTC) of existing electric generating facilities. These comments augment those already submitted by Dynegy to the CEC after the May 26th workshop regarding these same issues.

The comments below specifically address the six "Questions for Generator/Developer/Bidder Panel" raised in the notice for the CEC workshop.

1. Can OTC replacement be done via the IOU's RFO process?

As previously submitted, Dynegy believes that the utility RFO process can be structured to procure replacement facilities for units closed as a result of new 316 (b) regulations. Important improvements need to be made to the RFO process to accomplish this goal. These improvements include:

- The provision of long-term contracts (i.e. 20 yrs. or greater – 15 won't do it)
- Increased transparency and independence of the bid evaluation criteria and process
- Allowing bids in the RFO that reflect the retrofit of existing units with technologies compliant with 316 (b) requirements. Given the fact that existing units largely represent sunk costs, it may prove economic for an existing unit to be retrofitted with an alternative cooling technology. While the heat rates may not approach those of new units, the lower amount of incremental capital required, coupled with desirable operating

characteristics of boiler units (such as low turn-down capability and high ramp rates) may prove a superior choice to a new combined-cycle or simple cycle unit, depending on the anticipated nature and duration of the grid's need.

- A thorough overhaul of the allocation of risks in any associated Power Purchase Agreement (PPA) should be undertaken in advance of the RFO. There are indeed a number of operational and facility cost risks that asset owners are best positioned to manage and should thus be expected to bear. It is through this allocation of risk that unit performance is maximized and cost to the consumer minimized.
- Increasingly however, utility RFO's have been compounding performance penalties such that entering into such agreements is inappropriately onerous to the owner of the asset. The more one-sided, numerous, and expensive the penalties, the greater the price sought by the asset owner in order to preserve his desired likely net return. Beyond a certain point, multiple penalties secure no greater level of asset performance and serve no benefit to the consumer. Such provisions may be seen as "consumer insurance policies" by utilities, but they come at increased cost to the rate payer, discourage asset owners from participating in RFO's, and skew RFO evaluations in favor of utility self build options, which have no corresponding obligations (i.e. consumers pay for 100% of the cost of the utility-built, cost-of-service asset regardless of availability, performance or efficiency). Additionally, it is not clear that either the CPUC or the consumer has asked for this insurance nor are they made aware of the associated cost.
- Additionally, most PPA's increasingly seek to force the great majority of regulatory risks onto the asset. Asset owners generally have no means of managing the risks posed by future changes in regulation and, in most cases, they have no subsequent means of passing on the associated costs. As a result, the only means available to many asset owners to manage such risk is through the initial pricing of the contract. Again, the consumer ultimately pays via higher rates and diminished participation in the RFO. A similar argument can be made for force majeure risks.
- Dynegy believes that the RFO process would be well served by an investigation into the proper allocation of risks, with participation by potential bidders, utilities, the Office of Ratepayer Advocates, and consumer protection groups such as TURN. Ultimately, ratepayers should be well served by a contracting philosophy which places specific risks on those parties best poised to manage them.

2. How should an RFO be structured, what changes are needed from the current process to facilitate competition between possible Greenfield sites, building new units on existing sites, and repowers that replace cooling systems?

It is important to structure RFO's such that they adequately state the grid resource adequacy, reliability, and renewable energy integration requirements and then allow market participants to bid to fill the need. Effort should be made to resist over prescribing or predetermining the technology to be deployed. Similarly, precautions should be taken to prevent defining the allowable locations too narrowly.

Bid evaluation should be comprehensive enough in scope to capture all costs related with a project, including the costs of transmission expansion, build-out of fuel supply systems, supply behind transmission expansion, future emissions costs, etc.

3. How should RFO products be targeted to a particular location / product type?

To the extent that closure of any once-through cooled units creates concerns for the California Independent System Operator (CAISO) regarding local reliability, overall system supply adequacy, or the integration of renewable resources the CAISO would be best served to state the anticipated need and any locational requirements.

4. Do the current markets provide adequate incentives to design plants to provide ancillary services (e.g. regulation, etc) to integrate renewable into the system?

While markets for ancillary services exist, and provide incentive for the provision of such services from existing generation, their short-term nature and lack of depth make them an insufficient market to justify the construction of a new facility. However, even if the markets were more robust, it is unlikely that the strength of a spot market would be sufficient to attract capital. This would be equally true of a capacity market. Since the energy crisis years, it is difficult to believe that projects could be advanced simply on faith in a projected price curve of commodities that trade in short term markets. Plants are no longer "built on spec".

New facilities are likely only to be built if backed by a long term contract with a creditworthy counter-party. Utilities are the most likely source of such contracts. The existence of well functioning markets for energy, ancillary services, and capacity would serve to improve the environment for utilities to sign long term contracts by providing a secondary market that could be used as a means of shedding any excess procurement created by a loss of customers or other decreases in demand.

5. What length of contract is optimal?

Traditionally, investments in new power plants have been considered to be 30 year investments. From a power plant developer's standpoint 30 years would be optimal, as it matches the life of the asset with a predictable revenue stream. It would also implicitly put an independent power project at parity with utility self-build projects, whose depreciable life as a rate-based asset would be comparable.

As a practical consideration, it is difficult to provide competitive pricing and secure financing for a project backed by a contract of fewer than 20 years in duration. The longer the life of the contract, the easier it is to find a means to finance it.

6. How would a repowering via AB 1576 be conducted/approved/completed?

AB 1576 should be a consideration in the evaluation of competitive bids, as it recognizes the benefits of repowering existing facilities.

Many of these benefits should already manifest themselves in the form of a competitive overall cost, as repowered projects should be able to capitalize on existing fuel lines, transmission lines, roads, etc. That the repowered project would have access to emission credits created by the retirement of the existing OTC units would also serve to keep costs lower.

However, not all of the benefits of a repowering project will be explicitly apparent in a cost comparison. Repowering these units would allow for continued local employment and tax base in communities that are in need of both. The repowered projects would, in many cases, result in diminished local noise, diminished emissions, and a neutral to improved aesthetic impact to their local communities. It would also decrease the need to disturb greenfield areas.

The CPUC has already recognized the benefits of redevelopment. In D.04-12-048 the CPUC directed the utilities to, "consider the use of Brownfield sites first and take full advantage of their location before they consider building new generation on Greenfield sites. If IOUs decide
not to use Brownfield, they must make a showing that justifies their decision." In D.07-12-052 , the CPUC gave further direction for the utilities to, "consider repowered or replacement options presented in a RFO (i.e., not strictly for UOG projects, as some IOU representatives indicated they had interpreted this directive in D.04-12-048) before they choose options developed on Greenfield sites, or make a showing that justifies their decision not to do so." Despite this continued direction from the CPUC, it is not transparent to RFO participants that all repowered projects have been evaluated according to the guidelines set out in the LTPP decisions.

The CPUC should require the utilities to demonstrate that the benefits of repowering have been looked at and to use such factors as a basis for rewarding bids to repowered projects that are otherwise comparably priced with other options. Further, the CPUC should provide more transparency to the RFO participants on why repowered projects were not chosen.

The inclusion of AB1576 considerations into bid evaluations should not greatly skew the opportunity for other projects to compete. It should be recognized that the closure of an existing facility, due to the nature of how emissions reduction credits are created (i.e. fewer credits are created than the plant has historically created emissions), will likely afford an opportunity to replace only a portion of the former units' capacity. Other resources of other types and locations would also likely be required.

Dynegy appreciates the opportunity to comment on these important issues. If you have any questions concerning our comments, please call me at 926-803-5104.

Sincerely,

Randall Hickock

Randall Hickock
Managing Director - Asset Management West

cc: Commissioner Karen Douglas, Chair, California Energy Commission
Commissioner Jeff Byron, California Energy Commission
Commissioner Jim Boyd, California Energy Commission
Commissioner Michael Peevey, Chair, California Public Utilities Commission
Commissioner John Bohn, California Public Utilities Commission
Mr. Yakout Mansour, President, California Independent System Operator
Chair and Members of the State Water Resources Control Board
Mr. Dan Pelliseer, Acting Deputy Cabinet Secretary, Office of the Governor