A Sempra Energy utility®

Wayne Sakarias
Director
Regulatory Policy & Legislative Analysis

8330 Century Park Court
San Diego, Ca 92123

Tel: 858-654-1296
Fax: 858-654-1879
E-mail: wsakarias@semprautilities.com

October 28, 2011

Little Hoover Commission
925 L Street
Sacramento, CA 95814

Attn: Stuart Drown, Executive Director
Carole D'Elia, Deputy Executive Director

Re: Comments of San Diego Gas & Electric Company on Energy Governance

Dear Mr. Drown and Ms. D'Elia:

In response to Mr. Drown's request in his letter of October 5, 2011, attached is a copy of the Comments of San Diego Gas & Electric Company in respect of the Little Hoover Commission's examination of the state's coordination of energy-related activities.

If you have any questions about these comments, feel free to contact me at (858) 654-1296 or via e-mail at wsakarias@semprautilities.com.

Sincerely,

Wayne P. Sakarias
Director – Regulatory Policy & Legislative Analysis
San Diego Gas & Electric Company

COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY ON KEY ISSUES RELATING TO ENERGY AGENCY COORDINATION

San Diego Gas & Electric Company (SDG&E) appreciates the opportunity to offer our comments in response to the Little Hoover Commission's examination of energy agency coordination.

The Little Hoover Commission has asked for comments on the progress of state and federal agencies in facilitating renewables goals and local efforts to improve the generation and delivery of power to consumers. In particular, the Commission has indicated that it is exploring coordination efforts among entities that share authority over energy policy, permitting, siting, and regulation.

Among other things, the Commission has indicated that it seeks to understand --

- Progress in meeting state renewables goals
- How the cost of implementing these goals will be absorbed or passed to customers
- The ability of state organizations to facilitate success
- The need for governance or organizational changes
- Recommendations for administrative or statutory remedies to align processes

From our perspective, the goals that underlie the commission's request are –

1. Achieve 33% renewables by year 2020 and meet AB32 GHG reduction targets
2. Manage rate impacts
3. Promote distributed generation, when cost-effective

Our issues with respect to the roadblocks that interfere with these goals do not relate so much with the design of the organizations as they do with the process the State is using. Accordingly, we do not propose a change in the organizational design. But, we do suggest that the State needs to redesign some of its processes.

In particular, we offer comments and suggested resolutions relating to the following key areas:

- The permitting and project approval process (including coordination between the CPUC and the CAISO), and
- The coordination among State agencies in developing policies that could increase energy customers' rates.

1. **Piecemeal execution of permitting and project approvals**

By our observation, permitting time for major projects in California is 2-3 times as long as for permitting projects out-of-state, and permitting costs could be as much as 5 times more inside California than outside of the State. This long approval time is the product of, among other things, (1) agency processes that do not force parties to adhere to strict schedules and allows parties to use the process for delay, and (2) agencies' efforts to ensure a complete record so that courts will be unlikely to overturn the agency action. These complications evidence basic flaws in the State's process for permitting projects that are infused with the public interest, and the State needs to develop changes to these processes if it hopes to accomplish its renewable and GHG goals at a reasonable cost and in a timely manner.

Permitting authorities are confronted, at times, with parties whose main goal is to delay the permitting process, under the theory that a project delayed could turn into a project that fails, thereby accomplishing those parties' goals even if they would lose on the merits. Moreover, even after the initial permitting process concludes, parties continue to use the process to prevent an approved project from being built through a stream of administrative and judicial challenges that take years to complete. Project sponsors that cannot absorb the financial uncertainties that these challenges create may abandon their projects sometime during this process.

Even for projects that press forward in the face of this permitting obstacle course, there are significant consequences. The delays and added requirements to obtain approval and address post-approval challenges all add to the cost of projects. For energy-related projects, this results in higher rates that utility customers must pay, directly frustrating the CPUC's prime directive – to ensure that rates paid by utility customers are just and reasonable. There is nothing either just or reasonable about adding unnecessary costs to the permitting of a needed project as a result of excessive delays and unwarranted legal challenges.

While it is difficult to compare the experiences of different projects, they do provide some evidence of orders of magnitude differences between California and other states. Here is a comparison of the permitting, siting, and land rights costs for two somewhat similar projects:

- The Pawnee-Smoky Hill 345 kV Line (79 mile transmission line on mostly on new rights-of-way in Colorado): approximately $90,000 per mile
- The Sunrise Powerlink: approximately $1.5 million per mile

The Sunrise Powerlink experience shows the degree of detail necessary to permit a project in California today. The Environmental Impact Report for the Sunrise project was over 11,000 pages and cost of over $16 million, costs paid by ratepayers to CPUC consultants. Since the CPUC's granting of a Certificate of Public Convenience and Necessity for the Sunrise Powerlink, intervenors have pursued 35 post-approval State and federal appeals. Perhaps nothing speaks so graphically about the level of dysfunction of the California permitting process and its interaction with the federal permitting process than this lack of finality.

It is possible to do better than this, but the State needs the resolve to improve its current process, and state and federal governments need to do better in coordinating. A model of how quickly something can be accomplished when the State is committed is the rebuilding of Interstate 10 after the 1994 Northridge Earthquake. In that case, the freeway was reopened in half the time the schedule called for, even though that schedule was already an expedited schedule. According to a United States Department of Transportation Analysis –

> "Federal, state, local, industry leaders, and officials took a "hands-on role" in the stages of recovery. The early presence and participation of the Secretary of the USDOT, the FHWA Administrator, the Governor of California, the Director of Caltrans, the Mayor of Los Angeles, leadership within industry and the private sector, and many others, set a tone of commitment to the public. It demonstrated that government would work with the private sector to expedite the reconstruction effort."[1]

While circumstances are different than those arising out of an earthquake, the State nevertheless needs the same "tone of commitment to the public" to reduce red tape, corresponding project delays, and added cost to construct the infrastructure that California needs to meet its objectives.

Indeed, in the current legislative session, the legislature looked at ways to create swift closure to any judicial processes governing permitting so that a challenge to permitting is not used as a means simply to delay a project out of existence. For example, AB900 (Chapter 354, Statutes 2011) provides for streamlined judicial processes for certain types of projects designated by the Governor as "environmental leadership development projects." The State should inquire whether further refinements and expansions of this program should be added.

[1] U.S. Department of Transportation, *Effects Of Catastrophic Events On Transportation System Management And Operations, Northridge Earthquake, January 17, 1994*, April 22, 2002.

Balanced solutions are difficult to define and SDG&E does not claim to have all of the answers to these difficult questions. In addition to the remedy discussed above, here are some additional ideas we have considered:

CPUC

1. The CPUC should exercise its rebuttable presumption to rely upon California Independent System Operator (CAISO) economic and reliability justification for "need" where the CAISO conducts an economic assessment of proposed projects relative to alternatives that is subject to a robust stakeholder process. This will help to avoid duplicative CPUC and intervenor analysis of prior CAISO analysis.

2. The State should impose limits on the open-ended nature of interventions by strictly interpreting the rules for compensation and providing intervenors incentives to settle. As an example of how the intervenor process has gotten out of hand, SDG&E was required to pay over $2 million in Sunrise intervenor compensation. This prospect gives intervenors an incentive to obstruct and extend the transmission licensing process. By way of comparison, the State of Minnesota has adopted similar intervenor compensation rules, but cap payment to any single intervenor to $50,000[2]. This helps to avoid intervenors using regulatory process as a profit center, as opposed to as an opportunity to inject important public interests. The development of intervenor compensation rules is a delicate balance and we make no specific proposal today, other than to suggest that the intervenor compensation process tends to reward parties for opposing new infrastructure – usually, the same infrastructure needed to meet the State's aggressive energy goals.

3. As it stands today, network upgrades identified in the Generator Interconnection Process have no economic justification and, therefore, the CPUC may have no basis upon which to exercise a rebuttable presumption of economic "need." This interferes with timely permit processing because it forces the CPUC to consider alternatives that could have been not examined in the CAISO process. The CPUC and the CAISO should coordinate so that the CAISO can conduct economic assessments of network upgrades identified for full deliverability of the projects in the CAISO's Generator Interconnection Process in order to establish an economic need for those network upgrades.

[2] 2011 Minnesota Statutes Section 216B.16, subd 10(b).

4. In some cases, more extreme action might be appropriate, such as issuing default project approvals if statutory time limits are not met.[3] If this were adopted, default approvals should not be subject to either administrative or judicial appeals since that would defeat the entire purpose of invoking the default approval. The State should consider whether there are circumstances when a default approval is reasonable and in the public interest.

CEQA

1. Limit environmental review to clearly defined CEQA scope guidelines. This will minimize "scope creep" unnecessarily beyond CEQA law.

2. Impose funding limits on Environmental Impact Report (EIR) consultants to minimize study expansion and extension, and better manage ratepayer costs.

3. Establish a mitigation bank; reduce ratios from 3:1 to 1:1.

CEC

1. Eliminate formal court-type administrative hearings on license applications to simplify proceedings and reduce opportunities for delaying tactics.

2. Eliminate duplicative CEC staff analysis by requiring the CEC to rely on analyses/reviews and mitigation identified by other agencies, particularly for air and water impacts.

3. CEC should adopt standards for impacts that are not addressed by local and/or other agencies so that reviews are routine, expeditious, and developers can anticipate what is required. Currently, the CEC has few such standards.

CAISO

The California Independent System Operator coordinates with the CPUC on decisions relating to the process for determining resource adequacy (RA) needs. Public utilities Code Section 380 specifically requires that "The commission, in consultation with the Independent System Operator, shall establish resource adequacy requirements

[3] This is used in some other states already. For example, the State of New Mexico provides: "The commission shall issue its order granting or denying the application within nine months from the date the application is filed with the commission. Failure to issue its order within nine months is deemed to be approval and final disposition of the application; provided, however, that the commission may extend the time for granting approval for an additional six months for good cause shown." N.M. STAT. § 62-9-1(C).

for all load-serving entities." The CAISO determines local and system RA requirements for all load serving entities within the CAISO Balancing Authority area. For local RA, the CAISO conducts the studies that establish Local Capacity Requirements (LCR). The CAISO also conducts the studies that determine the network upgrades that—given the CAISO's study methodology—would allow interconnecting generators to count towards LCRs and system RA requirements. We are concerned that, at present, the CAISO is using a fundamentally flawed and outdated study methodology that identifies far more transmission upgrades than will ever be needed to accommodate existing renewable resource requirements and Greenhouse Gas emission reduction targets. The funding obligation that these transmission upgrades impose on prospective renewable resource projects is jeopardizing California's ability to meet its renewable requirements.

In carrying out its responsibility under Section 380 and its responsibility to the electric consumers in the State, the CPUC should coordinate with the CAISO to ensure that the CAISO's study methodology is not resulting in unreasonable costs or unnecessary renewable project uncertainty that would jeopardize the ability to meet RPS requirements. We believe that the CPUC should coordinate with the CAISO under Section 380 to ensure that there is an appropriate level of sanity checking on study inputs, methodology, results, and economic consequences, so that if a study methodology update and overhaul is needed, steps are taken to ensure that improvement occurs before further uncertainty unnecessarily jeopardizes renewables projects.

2. Inadequate Coordination Among Agencies on Issues That Could Raise Customers' Rates

Distributed Generation

California policy favors the development of renewable energy, but it also favors protecting customers from unreasonable costs. State agencies need to coordinate better to properly balance these dual policies. For example, the CEC recently issued a 337 page report on renewables policy that did not discuss the rate impact of policy considerations the CEC was exploring. While we understand that the CEC is not in charge of setting rates for end use electric customers, we also think that the identification of important state policies that drive agency action cannot be carried out in isolation, ignoring important rate issues that another agency must consider. The consideration of rate impacts is particularly important in the current economic climate. Division of regulatory responsibilities among state agencies should not cause important public policy issues to be considered on the basis of incomplete analysis.

Additionally, while state law specifically requires that cost to electric customers be a key consideration in the drive toward 33% renewables [SBx1 2 (Ch. 1, Statutes of 2011-12 First Extraordinary Session)], we see no coordination among the state agencies on ensuring similar protections in respect of DG programs.

Yet the rate impacts of DG programs, particularly on customers that do not have DG, could be profound and could be further magnified by contorted rate design required by state statutes adopted during the energy crisis that long ago became a counterproductive anachronism.

- Distributed generation tends to be relatively more costly than larger renewables. The Draft Report acknowledges the presence of these economies of scale, but dismisses them as either unimportant or disappearing (*see, e.g.* p. 15).

- Prudent planning in the interest of managing retail electricity rates would favor taking advantage of the cost efficiencies inherent in economies of scale in order to lessen the rate impacts of the program. Prudent planning would not encourage unnecessary added costs to retail customers.
- Current rate structures allow end-use customers with DG to receive certain electric services for free (for example, the costs of the distribution, transmission and generation infrastructure necessary to provide the end-use customer with reliable service at all times, and the cost associated with the free storage service inherent in net energy metering), shifting the cost of providing those services to retail customers without DG. The level and impact of this cost shift is growing in magnitude exponentially.

We would have expected coordination among the agencies on these issues, but have not seen evidence of it.

The consequences of this lack of attention to and coordination regarding customer rate impacts can be quite severe. For example, due to distortions in rates mandated by current law, as one customer takes advantage of distributed solar in order to avoid upper tier rates, that customer is also able to avoid paying the costs incurred in providing the customer with reliability service, including the costs of system upgrades necessary to integrate exports of excess generation into the distribution grid. These costs are then allocated to a declining number of remaining upper tier customers. Importantly, those upper tier customers that cannot afford solar, or do not own a home, have no ability to escape these costs, and are left entirely unprotected under these policies.

Existing rate design also poses a significant obstacle to the continued growth of distributed renewable generation and net zero energy construction policies in the future. Under existing utility rate design a net zero energy customer would not pay anything to SDG&E for the electricity network service the customer uses to ensure electricity is available when they need it. The costs incurred by SDG&E to provide these services would be allocated to remaining upper tier customers. Since a disproportionate number of solar investments are being made by the wealthiest utility residential customers, the direct result of this is to shift the responsibility to pay for utility services from the wealthiest residential customers to those less wealthy. Moreover, under existing rate design, wealthier customers that install DG can also avoid paying their share of public purpose programs, such as support for low income customers.

The CEC's Draft Report on renewables does not even identify this problem even though it is probably the single most significant element that could impact the sustainability of the state's DG programs. As DG programs for residential customers increase, current rate design shifts increasing costs to relatively lower income customers. At the levels suggested in the Draft Report, the shifting of costs in SDG&E's service area alone will be in the tens to hundreds of millions of dollars every year.

State agencies need to coordinate their policy discussions on DG issues and ensure that these rate consequences are fully acknowledged, and solutions identified and implemented.

AB32

An additional agency coordination issue arises in the context of AB32 implementation. AB32 will result in potentially significant costs being incurred both in the payment of fees to the California Air Resources Board, and in the payment for allowances to conform to AB32's requirements. Some of these costs are expected to be offset by the sale of free allowances that are allocated to electric distribution companies, and that are expected to be allocated to gas distribution companies. State law requires that the CARB and CPUC coordinate with each other in establishing rules and practices in implementing AB32.

We are concerned that these two agencies may not be coordinating as effectively as possible. For example, the CARB adopted administrative fees for carrying out AB32 implementation based on an assumption that the CPUC would authorize the State's investor-owned utilities to recover those fees from end-users (i.e., their customers). Prior to CARB's adoption of its administrative fee regulation, in June 2009, the Director of the Energy Division of the CPUC sent a letter to the CARB reassuring the CARB that the CPUC would be able to allow the utilities to pass those costs on to their customers. However, an application by the State's utilities to authorize recovery of those fees from their customers remains pending, and it remains unclear whether the utilities will indeed be authorized to recover these significant costs from their customers.

As another example, the revenues from the auction of free allowances should be returned to consumers to offset the cost they are incurring to implement GHG reducing measures, such as the energy efficiency and 33% renewables programs. However, we understand that there is considerable dialogue at CARB and elsewhere supporting a diversion of some of these auction revenues away from end use customers to fund other projects. We are unaware of any coordination between the CPUC, as the state agency representative of end use electric and gas customers, and the CARB, or with other agencies, to ensure that our customers' interest in just and reasonable rates is protected.

Conclusion

Ensuring that State law and policies are implemented consistently and efficiently requires coordination of, and concerted effort by, the State's various administrative agencies. We recognize that this poses significant challenges for State agencies, acknowledge that great strides have been made to overcome those challenges, and appreciate the opportunity to suggest areas for improvement.