California ISO
Your Link to Power

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Yakout Mansour, President and Chief Executive Officer

Date: May 12, 2010

Re: **CEO Report**

This memorandum does not require Board action.

1. 2009 MARKET ISSUES AND PERFORMANCE

This year's annual Market Issues and Performance Report prepared by the ISO's Department of Market Monitoring (DMM) holds special significance since it covers the first nine months of operations of the new market design. At the very highest level the report found the new day-ahead and real-time markets in 2009 to be highly efficient and competitive, with strong indications the new design increased market efficiency and reduced costs in a variety of ways. Positive results with respect to market fundamentals such as high levels of day-ahead scheduling, close convergence of day-ahead and real-time prices, and the high degree of forward contracting by load-serving entities among others contributed to this finding.

In addition, there are several highlights of this year's report worth noting:

- Prices in the day-ahead and real-time energy markets followed patterns of well-functioning competitive markets, reflecting production costs and trending generally with the price of natural gas, the most prevalent fuel for marginal resources on the system.

- Total estimated actual wholesale costs for serving system load declined from \$53/MWh in 2008 to \$38/MWh in 2009.

- The cost of ancillary services declined from \$0.74/MWh in 2008 to \$0.39/MWh in 2009, representing just 1% of wholesale energy costs and comparing favorably to other ISO/RTOs.

- Exceptional dispatch decreased to less than 0.5% of total system energy in the last three months of 2009, down from a range of 1% to 2% in earlier months.

- Net capacity for the ISO balancing authority area increased by 2,410 MW over the entire the year, much of which came on line prior to the start of summer in 2009.

- The frequency and impact of bid mitigation on prices was generally low. This is a reflection of disciplined behavior by the market participants.

These results generally reflect that the new market design was off to a very good start and continues. We are committed to complete all remaining market features to the same level and continue to target performance improvement as one of our main objectives.

2. NEW MARKET FUNCTIONALITY

The ISO continues implementation of the market initiatives prioritized through the stakeholder ranking process as well as others that were mandated by the Federal Energy Regulatory Commission. These enhancements build on the platform established with the deployment of the new market design, and will evolve the market towards the objectives established in the strategic plan.

As expected, April was a pivotal month with the deployment of two functional elements, including ancillary services procurement in the hour-ahead scheduling process on April 1 and forbidden operating regions on April 15. Two additional functional elements that were scheduled, namely scarcity pricing for April 1 and proxy demand resource for May 1, were not activated due to regulatory process extension. This functionality is nonetheless ready to be deployed as currently designed, with possible adjustments being required depending on the outcome of the FERC regulatory proceedings.

3. TRANSMISSION PLANNING

A primary function of the ISO is to plan the expansion of transmission capability within our footprint to meet the evolving needs of the system. As the Board is well aware, the state's ambitious renewables portfolio standard (RPS) goals present significant challenges with regard to planning and infrastructure development. While we routinely hear concerns about transmission being an impediment to meeting the RPS goals, we shouldn't lose sight of what we have accomplished to date and the limits to doing more at this point given the uncertainty about where the remaining renewable generation needed to meet a 33% RPS will ultimately come from.

With regard to what we have accomplished to date, we have approved three major transmission projects that collectively, along with other identified collector facilities, will enable approximately 8,000 MW of new renewable generation to connect to the grid - the Tehachapi Transmission Project, the Sunrise Power Link, and the California portion of what was originally the Palo Verde to Devers II project. If the expected renewable generation from these facilities materializes, their production, coupled with output from other existing renewable resources, would meet the 20% RPS goal and exceed it depending on the level of renewable energy imported from out-of-state. In addition, we have approved through an interconnection agreement a 35-mile 220 kV transmission line to access 1,400 MW of proposed new solar generation located near the southern California – Nevada border. While there are a large number of renewable projects in our interconnection queues that can utilize these approved network facilities, many do not have power purchase agreements and whether they will ultimately go forward is uncertain. In the meantime, we see many renewable projects wanting to build in other locations where transmission has not yet been identified.

Over the coming months, we anticipate even more transmission network upgrades moving forward based on the results of the ongoing LGIP transition cluster studies, and we are diligently pursuing this study process to facilitate projects seeking ARRA funding. Moreover, our interconnection process provides a separate expedited study process for interconnecting projects that can utilize existing transmission, which provides the right incentive for developers to take advantage of existing transmission. With all of these accomplishments, we are well on our way to identifying and approving the transmission needed to achieve a 33% RPS.

Planning beyond this is challenging due to the uncertainty about where the remainder of renewable resources necessary to achieve 33% RPS will come from. Our strategy for addressing this is, among other things, to work collaboratively with other planning entities in the state including the California Transmission Planning Group to assess different potential scenarios. However, the potential scenarios are so wide ranging at this point that it may be difficult to find a set of least regrets transmission elements. The purpose of these studies is to explore the transmission implications of these different scenarios and recalibrate as we get greater certainty on where these renewable resources will ultimately come from. Conversely, our planning studies, by identifying the transmission needs for each scenario, will help inform the procurement and resource development process, particularly the long-term procurement proceeding at the CPUC.

This high degree of uncertainty on the future renewable build-out is precisely why it is impossible to effectively evaluate the merits of any individual proposed transmission project in a vacuum. Over the past two planning cycles, we have received a number of transmission project proposals from both PTOs and third parties. These projects were submitted as economic projects for the ISO to evaluate in our transmission planning process with many citing interconnection of renewable generation as one of the main economic benefits. What we have consistently told both PTOs and the third party developers is that we cannot effectively evaluate the merits of their proposed projects absent a clear picture of where the renewable generation will come from and the transmission needed to support it. Accordingly, we have deferred consideration of their projects until we have sufficiently assessed these matters and developed some comprehensive planning scenarios, which will provide the proper framework for evaluating these projects and mitigate the risk of stranded investment.

Our strategy for effectively planning the needs of the system to support a 33% RPS also involves making major reforms to our transmission planning process. Most notably, the reforms include new criteria that allow us to approve transmission projects to support state and federal policies – including the state RPS goal. It also provides a much more comprehensive and streamlined approach to planning the system that will enable us to address reliability, generation interconnections, policy objectives, and economic consideration in one unified planning process that produces a comprehensive plan each year for the Board to approve.

The development of these reforms has been controversial, particularly with regard to the implications of this proposal on who gets to build the identified transmission needs. On this issue, we believe we have struck the right balance that maintains the obligations, existing in the current tariff and

Transmission Control Agreement, for our PTOs with service territories to maintain and plan for their systems while still providing a meaningful role for third party transmission developers. Third party transmission developers had played significant roles in recent major transmission projects in our area, and there is nothing we are proposing that would foreclose opportunities like that going forward. Moreover, another opportunity for independents will come from collaboration with our incumbent PTOs to identify opportunities for joint projects such as Citizens Energy's joint development with San Diego Gas & Electric in developing the Sunrise Power Link.

In summary, we believe our proactive planning activities for renewable integration has already accomplished a lot to support renewable development. There is always more to do and we are committed to doing more but identifying additional transmission needs at this point will be very challenging given the uncertainty about where the remaining renewable generation needed to meet a 33% RPS will ultimately come from.

4. 2010 SUMMER LOADS AND RESOURCES

Each year the ISO presents the expected supply and demand conditions for the 2010 summer peak demand period. The summer assessment provides the organization and interested stakeholders an assessment of the load and resource picture for the ensuing summer season, which helps in planning and preparing for the upcoming summer season, a process that is already well underway.

Supply for summer 2010 is adequate to handle a broad range of conditions but system operations may nonetheless be challenged at the extremes, particularly if heat waves combine with wildfires and force increased reliance on local generation. The need to maximize imports into southern California under a variety of conditions, including such extremes, is essential to maintain adequate supply. For a second consecutive year the probability for firm load shedding remains at low levels, less than 1% for the ISO as a system, as the recession continues to reduce peak demand loads. In addition, the ISO will be counting on 2,400 MW of demand response programs and the Flex Your Power conservation program when necessary during extreme conditions.

Other key findings in this year's assessment include:

- Hydro conditions for 2010 have improved with the statewide average snow water content measured at 150% of historical average as of May 3, 2010, while this El Nino weather pattern also appears to have resulted in below normal precipitation in the Pacific Northwest.

- An additional 1,760 MW of new generation is expected to come on line between the beginning of last summer and June 1, 2010, consisting of 1,680 MW of thermal generation and 80 MW of renewable resources, with 1,727 MW located South of Path 26 and 33 MW North of Path 26.

- The peak demand forecast is 47,139 MW, 2.9% above last summer's peak, based on economic data that represents a modest economic recovery over 2009.