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Witness: Gary Ackerman

TESTIMONY OF THE WESTERN POWER TRADING FORUM ON TRACK 4 ISSUES

ORDER INSTITUTING RULEMAKING TO INTEGRATE AND REFINE PROCUREMENT POLICIES AND CONSIDER LONG-TERM PROCUREMENT PLANS

WPTF
Western Power Trading Forum

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TESTIMONY OF THE WESTERN POWER TRADING FORUM ON TRACK 4 ISSUES

Chapter I – Introduction and Summary

This testimony is submitted on behalf of the Western Power Trading Forum ("WPTF") in response to the September 16, 2013, Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 and Track 4 Schedules ("September 16 Ruling"). Specifically, the September 16 Ruling set this date for the service of reply to the opening testimony of the California Independent System Operator ("CAISO"), Southern California Edison ("SCE"), San Diego Gas & Electric ("SDG&E") and the City of Redondo Beach; opening testimony of all other parties; and comments on questions posed by Administrative Law Judge ("ALJ") David Gamson at the September 4, 2013 prehearing conference. My testimony focuses on the proposals made by SCE in its opening testimony with regard to "addressing long term Local Capacity Requirements (LCR) needs in SCE's service area with all Once Through Cooling (OTC) generating facilities, including San Onofre Nuclear Generating Station Unit Nos. 2 and 3 (SONGS), retired in 2022."[1]

Subject to the issues raised in this testimony, WPTF does not oppose SCE's Track 4 proposals. The combination of new gas-fired generation, transmission upgrades and the preferred resources scenario, backstopped by the proposed contingent resources strategy is a reasonable approach to address the retirement of SONGS. However, there are several aspects of SCE's proposals that can be improved and are the focus of WPTF's testimony – specifically the benefits of competitive procurement to meet the utility's planned needs; improvements to the

[1] SCE, at p. 1.

two contingency proposals included in the proposals; and SCE's cost allocation mechanism proposal.

A. Description of WPTF

WPTF is a California non-profit, mutual benefit corporation. It is a broadly based membership organization dedicated to enhancing competition in Western electric markets in order to reduce the cost of electricity to consumers throughout the region while maintaining the current high level of system reliability. WPTF actions are focused on supporting development of competitive electricity markets throughout the region and developing uniform operating rules to facilitate transactions among market participants.

WPTF provides a voice through which its members can influence the development of market structures throughout the West. The membership of WPTF includes generators, scheduling coordinators, investment banks, energy service providers, energy consultants and public utilities, all of which are active participants in the restructured California electricity market. WPTF has a vital interest in the development of a competitive electric market and in the reduction of barriers that may exist in the very structure of new markets.

B. Testimony Format

My testimony thus has four chapters. Chapter I is this introduction that provides procedural background and a brief overview of my testimony. Chapter II deals with SCE's planned procurement of 500 MW of new gas-fired generation. Chapter III discusses recommended refinements to the two contingency plans that SCE has proposed – Option Contracts and Contingent Site Development. Chapter IV concludes with a discussion of issues related to the cost allocation mechanism.

My Statement of Qualifications is contained in Attachment 1 hereto.

Chapter II – New Resources

SCE notes that both it and the CAISO performed studies to determine the need for new local reliability resources in the LA Basin to replace retiring OTC plants and SONGS. SCE states that it developed its studies in collaboration with SDG&E which recommended using a load shedding scheme to plan for certain transmission contingencies arising in its service territory.[2] The incorporation of this load-shedding scheme is said to reduce SDG&E's dependence on imports from the LA Basin to meet its transmission contingency needs, thereby causing an overall reduction of the need for new generation in the LA Basin by 436 MW.

Although the CAISO identified an overall need for new generation of 3,722 MW in the LA Basin, SCE identified a lesser need of 2,802 MW, or 920 MW less. After accounting for the 436 MW associated with SDG&E load shed, SCE demonstrates that there remains a residual difference of 484 MW between the two estimates. The utility therefore concludes that an additional 500 MW (484 MW rounded to 500 MW) of new generation in the LA Basin above the need identified in SCE's studies is needed to assure that sufficient resources are available to meet CAISO's expectations of need. Therefore, SCE requests authorization to procure up to 500 MW of new resources to meet CAISO's assessment of need.

SCE's current LCR procurement authorization[3] requires SCE to procure a minimum of 150 MW of Preferred Resources, a minimum of 50 MW of Energy Storage, and at least 1,000 and up to 1,200 MW of gas-fired generation. An additional 200 MW can be sourced from any

[2] *See* SCE Chapter III.B which describes the transmission contingencies identified by SDG&E dealt with through a load shedding scheme.

[3] Decision ("D.") 13-02-015, on 20 Track 1 of this proceeding, authorized SCE to procure between 1,400 and 1,800 MW of new generation in the LA Basin and between 215 and 290 MW in the Moorpark subarea.

mix of technology, while the balance of the 400 MW of the utility's LCR procurement authorization is limited to Preferred Resources and Energy Storage.[4] SCE proposes that its requested Track 4 new resource procurement authorization of 500 MW be combined with SCE's current Track 1 authorization. Specifically, SCE proposes that the 500 MW Track 4 request be combined with the 200 MW of Track 1 LCR resources that can be sourced from any technology. SCE's testimony states the procurement must be consistent with the Preferred Loading Order. Based on discussions with SCE, WPTF understands that this procurement shall be conducted on a least-cost, best-fit basis. Subject to this condition, I find the SCE need analysis to be accurate and concur with the prudency of the SCE recommendation to combine the Track 4 and Track 1 procurement.

The SONGS situation no longer involves an outage of undetermined duration. It is now permanently retired and the Commission and the affected utilities need to move forward expeditiously to meet the affected need. SCE's recommendation to combine the Track 4 500 MW with its already authorized Track 1 procurement will serve to accelerate achieving a solution to the SONGS retirement that is timely and cost effective.

Cost effectiveness is also very likely to be achieved due to SCE's decision to rely on competitive procurement to meet these incremental requirements. Doing so is highly likely to stimulate significant interest among conventional generation and preferred resources developers and result in a robust response to a competitive request for offers. Ratepayers will of course benefit from this competition as it will lead to more efficient and cost-effective pricing under the resulting long-term power purchase agreements. The SCE approach to meeting its incremental resource needs is appropriate and should be approved by the Commission.

[4] D.13-02-015, Ordering Paragraph No. 1.

Chapter III – Refinements to the SCE Contingent Resources Strategy

In Chapter VII of SCE's testimony, it proposes a "Contingent Resources Strategy." Specifically, SCE plans to pursue two forms of contingent generation development to "backstop" the Transmission and Preferred Resources strategies previously addressed in this testimony. Each of these proposals is described and discussed below.

A. The Contingent Site Development Contingency Proposal

SCE proposes to undertake a Preferred Resources "Living" Pilot Program ("Pilot") to procure and evaluate the ability of Preferred Resources to meet LCR needs. The Pilot will focus on Preferred Resources that are located in the southern portion of SCE's service area in Orange County; specifically the areas served by Johanna and Santiago substations. In this regard, it notes that to date, "SCE has procured Preferred Resources to meet specific compliance targets (e.g. the 33% Renewables Portfolio Standard (RPS) target), but <u>not</u> to meet reliability needs."[5] As back-up to the possibility that these Preferred Resources do not come to fruition, or are determined to not have performed as expected, SCE has included in its Track 4 plan a proposal to develop generation sites in the vicinity of Johanna and Santiago substations that will be auctioned off to competitive third party developers, if it determined that the such resources are needed due to the Pilot's lack of success, referred to herein as "Contingent Site Development."

B. The Option Contracts Contingency Proposal

SCE is also planning to construct the Mesa Loop-In transmission expansion that will reduce the need for any additional new LA Basin LCR resources. SCE's Track 4 proposal contains a contingency plan for this project as well. SCE's Mesa Loop-In contingency proposal is to solicit and execute additional long term gas-fired PPAs that contain a buyer's right to

[5] SCE, at p. 49 (emphasis in original).

terminate subject to a termination payment, referred to as "Option Contracts." These additional PPAs would be solicited in the same RFO that will be conducted as a result of the Track 1 authorization.

SCE states that it plans to pursue securing the Option Contracts for gas-fired generation resources to backstop the Mesa Loop-In project. SCE plans to secure the Option Contracts in any of the three following ways: (i) bilateral negotiations, (ii) evaluating gas-fired generation projects in its Track 1 LCR procurement solicitation, and (iii) evaluating proposals received through its separate bilateral negotiations pursuant to the AB 1576 "cost of service" contracting authority the Commission provided in D.13-02-015.[6]

C. Comments on the SCE Contingency Resources Strategy

Subject to the caveats and safeguards recommended in the sections below, WPTF does not oppose the SCE Contingent Resources Strategy.

1. Existing Brown Field and OTC Sites should be Considered for both the Contingent Site Development *and* the Option Contracts

The Commission should make it clear that in pursuing both the Contingent Site Development and the Option Contracts contingency proposals, SCE should allow existing generators, including OTC unit owners, to offer their sites for redevelopment. The "greening" of an existing brown field or OTC site can offer several advantages. These sites already have air permits, transmission interconnections, natural gas interconnections, and can often be redeveloped on a timelier basis and at less cost than new green field development. Therefore,

[6] SCE states that it will submit any proposed contingent contracts to the Commission for approval, along with the projected expense of terminating the contingent contract(s) at various stages of development if it is determined that they are not necessary. SCE, at p. 59.

any approval of the SCE Option Contract strategy should note the potential for such efforts and require the utility to explore these possibilities.

Furthermore, such a directive would be consistent with SCE's Generation Resource Approach, as described in Section III.A.3 of its opening testimony.[7] In it, the utility notes that its analysis began with the development of an initial generation build out and that "an initial configuration of generation resources was developed, placing heavy reliance on repowering at known favorably situated OTC sites and/or nearby electrically equivalent locations (i.e. 1400 MW near Alamitos Generating Station and 1000 MW near Huntington Beach Generating Station) in the LA Basin."[8] This "heavy reliance" on repowering should be reflected in the two SCE contingency proposals.

2. The Postponement of OTC Retirement Dates Should be Considered.

The Commission should also consider other alternatives to the Contingent Resources Strategy, such as approaching the State Water Resources Control Board to explore a possible agreement whereby if the Mesa Loop-In is delayed then specific OTC retirements could also be postponed accordingly. This could be a significantly less-costly alternative approach to providing the necessary backstop.

3. An All-Party Request for Offers should be Approved Rather than Bilateral Negotiations.

WPTF opposes the concept of using bilateral negotiations for securing the Option Contracts. Bilateral negotiations do not ensure that the least cost option will be identified and selected. Further, it permits the utility to pick "winners and losers" on criteria other than least cost. The Commission should instead require SCE to include the contingent contract approach in

[7] SCE, at pp. 14-15.

[8] Ibid,

its planned RFO for both Track 1 and Track 4 resources, and prohibit separate bilateral negotiations.

4. The Capacity Amount of Option Contracts Needs to be Clarified.

SCE's testimony is not specific with regard to the amount of Option Contracts it plans to solicit. At one point, SCE says that after subtracting the LA Basin procurement already authorized in Track 1 of this proceeding from the 2800 MW need identified in SCE's Track 4 studies, there is a remaining need for about 1000 MW."[9] The utility states that, the "development of Mesa Loop-In and the strategically located Preferred Resources could displace the need for any additional new LCR resources, while still meeting NERC Reliability Standards."[10] Later, however, SCE states that the Mesa Loop-In by itself reduces the need for additional LCR resources by 1,196 MW.[11] So, it is not precisely clear what the failure or delay of the Mesa Loop-In might mean in terms of what amount of contingent resource contracts are required.

WPTF would suggest that no more than 1,000 MW of such contracts would be advisable and that the Commission should set such a level. Moreover, the Commission should make it clear in the Order just what the circumstances and time frame will be pursuant to which termination rights embedded in the Option Contracts must be exercised, as such specifics are necessary to ensure that the Option Contracts do not become the premise for more "unique fleeting opportunity" applications by SCE at a later date, as explained in more detail in Section III.C below.

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[9] SCE, at p. 3.

[10] Id.

[11] SCE, at p. 8.

D. Approval of the Contingent Resources Strategy Should Not be Deemed to Compromise the Fundamental Principle that IOU Development Costs Should be at Risk and Not Ratepayer Guaranteed.

While WPTF does not necessarily oppose the Contingent Resources Strategy, it is mindful that doing so runs close to abridging a critical principle for which WPTF has labored long and hard over the past dozen years. There is a fundamental disparity between UOG and independent developer project development costs. Depending on the type of UOG proposal, development costs may be recovered from ratepayers even if the project does not come to fruition, while PPA development costs are only recovered if the project gets built. As background, D.07-12-052 did not "permit IOUs to recoup from ratepayers any bid development costs associated with losing PSA or EPC bids, in the event that any such costs are incurred."[12] The Commission went on to note in the same discussion that:

> We agree with parties and find it important to recognize that even the perception of bias in an RFO can be sufficient to dampen participation from other potential non-utility investors and developers are less likely to get support from capital markets if there is a perception that merchant bids will be undermined by utility built or affiliate projects.[13]

This finding was consistent with the Commission's prior actions with regard to proposals of SCE for ratepayer funding of its Project Development Division ("PDD").[14] First proposed in SCE's 2006 GRC (A.04-12-014), the PDD raised a good deal of opposition from parties such as the Division of Ratepayer Advocates, Aglet and WPTF, all of whom objected to SCE's proposal to

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[12] D.07-12-052, at p. 207. As further clarification of these acronyms, footnote 233 at p. 197 of the decision provides, "For the purposes of this discussion, the term UOG includes, but is not limited to, utility-built, Engineer, Permit and Construct (EPC), and Purchase and Sale Agreement (PSA) acquired resources."

[13] Id, at p. 208.

[14] It appears that the PDD has been renamed Generation Planning. See qualifications of SCE witness Jonathan Rumble at p. B-7. For purposes of this discussion, my testimony continues use of the prior acronym of PDD.

use $4.95 million in test year 2006 ratepayer funding for utility generation project development in the competitive market structure that had been established by the Commission. In D.06-05-016, the Commission agreed with these concerns, finding that:

> While we recognize there is value in having more participants such as SCE in the process, we find it necessary to subject SCE to the same cost recovery risks as faced by independent producers. Independent producers' development costs associated with unsuccessful projects are not recoverable from ratepayers. It is a matter of fairness that SCE assume that same risk, if it chooses to participate.[15]

Subsequently, in its 2009 GRC (A.07-11-001), SCE sought a vast expansion of the PDD budget. The utility requested $5,012,000 to continue the PDD activities authorized for rate recovery in the 2006 GRC and another $21,572,000 to begin generation-related technology demonstration, testing, and evaluation and to fund the incremental staffing required to conduct that work. Once again, DRA and WPTF objected to this expansion of the PDD, and once again the Commission agreed:

> For the same reasons as set forth in D.06-05-016, we reject SCE's $20 million request for cost recovery of RD&D. In D.06-05-016, the Commission expressed concerns regarding the potential to create an uneven playing field for competitors. The Commission stated, "…from a policy perspective, we feel it is important that the project development costs for proposed new projects should not be specifically included in rates." These same concerns continue to exist. To address these concerns, the Commission excluded SCE's entire PDD request from rates.[16]

This same battle was fought and resolved in the same manner in SCE's 2012 GRC.[17]

Permitting utilities to recoup their development costs, regardless of whether a project gained Commission approval (whether through the approval of RFO results or a CPCN

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[15] D.06-05-016, at p. 52.

[16] D.09-03-025, at pp. 41-42.

[17] *See* D.12-11-051, at pp. 77-79.

application), would clearly add to the "perception of bias" that the Commission cautioned against. Recovery of such costs also creates a competitive advantage in favor of utility projects.

WPTF wishes to be explicit here. It does not oppose the SCE Contingent Resources Strategy as a one-time special circumstance to meet the unanticipated premature retirement of SONGS. However, this should not be permitted to serve as precedent to undermine the fundamental principle that utility project development costs that lead to UOG proposals should not be included in rates and should be borne by the utility's shareholders, as is the case with independent power developers.

E. The Option Contracts and Contingent Site Development Should Be Prohibited From Becoming the Next "Unique Fleeting Opportunity."

As described in the immediately preceding sections, SCE's Track 4 proposals have customers paying for two very big layers of contingencies. The Commission should be careful to recognize the momentum that can build behind such planning efforts. Once SCE starts spending money on these efforts, it will be natural for those involved to want their efforts to be more than merely hypothetical backstops. Moreover, as spending on these contingency plans continues, the fact that much of the cost is now sunk will make the contingency options look like increasingly attractive additional "insurance" even if the underlying projects (both the Mesa Loop-In and Preferred Resources) are moving forward.

This leads to the possibility that the SCE contingency plans could become the next "unique fleeting opportunity" for additional generation, and perhaps even utility-owned generation ("UOG") that causes the system to be overbuilt, erodes competition, and raises rates. While WPTF does not oppose SCE's Contingent Resources Strategy, subject to the comments and recommendations discussed above, it recommends that the Commission make it explicitly clear that such contingency plans will not be permitted to be converted at a later date into unneeded new generation. This can be accomplished by setting forth explicit criteria pursuant to which the Option Contracts can and will be terminated, rather than being built, and explicit criteria pursuant to which the sites established pursuant to the Contingent Site Development will be made available to prospective developers.

Chapter IV – Cost Allocation Mechanism Issues

SCE's request for Track 4 procurement authorization for 500 MW of new resources and potential contingent gas-fired generation Option Contracts, as well as the Contingent Site Development all appear to be premised on SCE receiving Cost Allocation Mechanism ("CAM") treatment. Since SB 695 was enacted, there have been numerous instances where the utilities have claimed that specific projects meet the criteria of SB 695, and therefore CAM cost allocation must be afforded. The decision about when to employ CAM will impact the procurement decisions of competitive retail suppliers because when CAM is employed, there are commensurate allocations of the underlying capacity to those suppliers. This "on-behalf of procurement" is anathema to competitive retail suppliers and their customers who elect retail service specifically as an alternative to utility service. Therefore, the application of CAM should be circumspect and limited.

Moreover, in this situation, SCE and SDG&E will be acting to replace an asset that has been solely dedicated to meeting bundled customer demand. It would be highly inappropriate to have the costs of replacement assets suddenly allocated in part to direct access customers. In regard to this subject, WPTF has had the opportunity to review and endorses the testimony of the Alliance for Retail Energy Markets and Direct Access Customer Coalition that is being served today.

This concludes my testimony.

Attachment 1

Statement of Qualifications

GARY B. ACKERMAN, President, Foothill Services Inc.

SPECIALIZED PROFESSIONAL COMPETENCE

Economic and political assessment of new energy ventures, including merchant-plant development, and development of electricity and natural gas trading and marketing; private-interest advocacy.

PROFESSIONAL EXPERIENCE

Western Power Trading Forum: Founder and executive director of a mutual-benefit, non-profit corporation. Mission is to encourage and promote lower electricity prices and enhanced system reliability in policies undertaken either by the Federal Energy Regulatory Commission (FERC), California Independent System Operator (ISO), or the California PUC. Current membership includes major market participants in the Western-states electricity business. (1998 – present).

ZGlobal Inc.: Marketing advisor on LMP software to forecast the impacts of the CAISO MRTU system. (2007 – present)

Automated Power Exchange: Expert witness testimony regarding dispute between cogeneration project (seller), a bankrupt Energy Service Provider, and the California Power Exchange (buyer). (2002)

Ridge Energy Group: Prepared study for Houston-based compressed-air storage developer on the market feasibility utilizing storage with wind-based energy sited in California or Arizona. (2002)

Southern Nevada Power Project: Co-developed the plan for a gas-fired generation project to be located in the Sandy Valley area of Southern Nevada. Project currently being developed by Diamond Energy (1995 – present)

Sale Agent for Rio Linda Power Generation Project: Represented the interests of developer/seller of 500 MW gas-fired project sited in Sacramento area to FPL Energy. Negotiated joint venture development agreement for re-siting facility before the California CEC. (1999 – 2001)

Occidental Petroleum: Advise natural gas marketing group on strategies to enhance value to electric generation buyers of gas commodity and storage services from client's Elk Hills facility in Bakersfield. (1999 - 2001)

Wellhead Electric: Advised cogeneration developer and operator on restructuring options in the new California market. (1998 - 1999)

Robinson-May Department Stores: Advised department-store chain regarding strategies for retail procurement of electricity. (1998)

Mock Energy Services/Avista Energy: Regulatory Affairs coordinator for the joint venture, represented client in all aspects of California electricity restructuring including the Independent System Operator/Power Exchange (ISO/PX) Trust Advisory Committee, WEPEX Steering Committee, and served as the President of the ISO's Scheduling Coordinator Users Group from February 1997 to January 1998.

Chevron U.S.A.: Development of a natural-gas-fueled merchant electric generating facility which would dramatically alter the way power is bought and sold in the western U.S. (1994 – 1995)

CSW Energy: Assistance to the independent power plant development non-regulated subsidiary of Dallas-based Central and Southwest Services. (1993 – 1995)

ARK/CSW Energy: Advise the cogeneration joint venture on all aspects of business development from earliest conceptual stages to the execution of power purchase agreements. (1991 – 1998)

Decision Focus, Inc.: Developed new business and sold utility planning software for DFI's electric, and gas and oil business. (1982 – 1989)

EDUCATION

University of Chicago - M.A., Economics, (1976)
Michigan State - B.A., Economics, (1973)

Publications

Reports:

1. Impact Assessment of the 1977 New York City Blackout, (with W.T. Miles, and J. Corwin), Special report for U.S. Department of Energy, Division of Electric Energy Systems, HCP/T5 103-01, Palo Alto, July 1978.

2.The Application of Energy Supply/Demand Models to Regional Power System Planning, (with F. Ma, J. Patmore, and D. Stengel), prepared for U.S. Department of Energy and the University of Oklahoma (DOE EC-77-S-05-5468), Palo Alto, June 1978.

3.U.S. Electric Power Grid Concepts: The Existing System and Proposed Concepts for Improvements to Bulk Power Supply, (with N. Badertsher, J. Corwin, and C. Sayler), reprinted in The National Power Grid Study, Vol. II, (Department of Energy), Washington, DC, September 1980.

4. Evaluation and Transfer of Electric Utility Models Using Comparison Methods, (with D. Budenaers, and R. Chen), prepared for EPRI (TPS 79-220), Palo Alto, May 1980.

5. Impact of Customer Load Management Technologies in Utilities' Load Shapes, (with M.L. Chan), prepared for EPRI RP 1084-1, Palo Alto, July 1979.

6. Benefits and Costs of Load Management: A Technical Assistance and Resource Material Handbook, (with R. Lau, J. Patmore, F. Ma, and Argonne National Laboratory), ANL/SPG-12, Chicago, June 1980.

7. Generation Planning and Reliability Study, (with T. Bowe, and W. Dapkus), prepared for the Illinois Commerce Commission, Palo Alto, August 1981.

8. Application of Decision Analysis to Electric-Utility Load-Leveling Strategies, prepared for Argonne National Labs (ANL-31-109-38-5306), Palo Alto, September 1981.

9. Analysis of Demand-side Options, prepared for East Kentucky Electric Power Cooperative (1986), Iowa Public Service (1986), and Los Angeles Department of Water and Power (1987).

10. Prospects for Supply, Transportation, Demand, and Price in Western Europe and Contiguous Regions, prepared for the sponsors of the DFI Western European Gas Program, Mountain View, August 1993.

Articles:

1.”Defense Expenditures and the Survival of American Capitalism,” Armed Forces and Society, (with C. Nardinelli), Vol. 3, No. 1, pp 13-16, Fall 1976.

2.”Short-Term Load Prediction for Economic Dispatch of Generation,” IEEE Conference Proceedings PICA-79, (with D. Ross, R. Bischke, R. Podmore, K. Wall), pp 198-204, May 1979.

3.”A Methodology to Evaluate the Costs and Benefits of Electric Customer Load-Management Technologies,” Energy Technology VII Proceedings, (with M.L. Chan, E. Marsh, and J. Yoon), pp 54-66, March 1980.

4.”Simulation-Based Load Synthesis Methodology for Evaluating Load-Management Programs”, IEEE Transactions on Power Apparatus and Systems, (with M.L. Chan, E. Marsh, and J. Yoon), Vol. PAS-100, No. 4, pp. 1771-1778, April 1981.

5.”Determining the Benefits and Costs of Load Management Systematically,” Public Utilities Fortnightly, (with R. Mueller), Vol. 1207, No. 9, pp 26-32, April 1981.

6.”Data Transfers Among Electric Utilities,” Public Utilities Fortnightly, Vol. 107, No. 9, pp 26-32, April 1982.

7.”Short-Term Load Prediction for Electric-Utility Control of Generating Units,” Short-Term Forecasting, D. Bunn and E. Farmer, eds., (Wiley Press, London) December 1985.

8.”Desktop Computers: Too Young to Offer Any Benefits?” Electrical World (McGraw-Hill, New York), July 1983.

9.”The Optimal Penetration of Direct Load Control Switches,” (with J. Gafford) Transmission and Distribution, (Cleworth Publishing, Cos Cob, CT), July 1983.

10.”Bridging the Planning and Operations Gap,” Electrical World, (McGraw-Hill Inc., NY, NY) October, 1987.

11.”How an Electric Utility Production Cost Model Can Be Validated,” (written on behalf of John Stremel, Decision Focus Inc., and William Stillinger, Northeast Utilities) Public Utilities Fortnightly, (Public Utilities Reports, Arlington, VA), December, 1988.

12. "Deal Triage," (co-authored with Robert Nicholson, Bank of America Global Project Finance), Infrastructure Finance, (Financial World Publications, New York) February, 1997.

13. "Buyers Beware the Confusion," (co-authored with Daniel Violette, and Harry Misuriello), Energy Buyer's Guide, (Information Forecast, Inc., Sherman Oaks, CA). May, 1997.

Professional Papers and Panels:

1. *"Attempts to Forecast the Demand for Electricity: The Commonwealth Edison Experience"*, (with G. Corey), Delivered at the University of Chicago, Econometrics and Statistics Colloquium, April 6, 1977.

2. *"Description of SCI Load Management Models,"* (with F. Ma) prepared for Argonne National Laboratory, Special Studies Group, September 1979.

3. *"Key Steps in Load-Management Evaluation and Transferability of Load Data,"* prepared for Argonne National Laboratory, Special Studies Group, October 1979.

4. *"Factors Affecting the Adaptation of Load Management,"* prepared for U.S. Department of Energy, Economic Regulatory Administration, October 1980.

5. *"Short Term Forecasting of Monthly Energy,"* prepared for the EPRI 6th Load Forecasting Symposium, Dallas, Texas, December 1982.

6. *"An Emerging Economic View of World Natural Gas"*, (with D.H. Dorsett, Chevron Corp.) prepared for the 1992 Society for Petroleum Engineers Oil and Gas Economics, Finance, and Management Conference, London, U.K., April 1992.

7. *"A Case Study of an American Demand Management Bid,"* (with James C Crossman, Financial Energy Management) prepared for the 1st National Demand Management Conference, Melbourne, Australia, May 1992.

8. "NUG Needs in an Order 636 World: Opportunities for LDC's", prepared for the AGA Strategic Planning Committee Meeting, San Francisco, CA, August 1992.

9. "Assuring the Independence of ISO's," prepared for the Power 97 Conference, Houston, Texas, July 1997.

10. "Market Participation: The Impacts of Cost and Complexity", (with Ken Nichols and Jenny Klein) prepared for the ISO Conference, Denver, March 1998.

11. "Report from the Front Lines: Status and Update on Implementing Regional Congestion Pricing Schemes", presented at the Infocast conference on Congestion Pricing and Tariffs, Washington, D.C., September 1998.

12. "The California Experience," presented at the EEI National Accounts Workshop, Chicago, September 1998.

13. "Scheduling Coordinators' Experience with the California ISO," presented at the California Coalition of Public Utility Counsels, Monterey, California, October 1998.

14. "Reviewing the California Experience," presented at the Energy NewsData Conference on Leaders & Strategies in the New Western Energy Market, Seattle, November 1998.

15. "Scheduling Coordinator Impressions of the ISO," presented at the Megawatt Daily Conference on California Power Markets, San Diego, February 1999
16. "Panel on Risk Management in Trading," presented at Distributech 1999, San Diego, February 1999.

17. "Demand Provision of Ancillary Services," presented at the Technical Advisory Committee of the California Board of Energy Efficiency, San Francisco, February 1999.

18. "Will Retail Competition Work in California?", key note speech presented at the Annual Sacramento Business Journal meeting on power issues, Sacramento, October 1999.

19. "What happened in California During the Summer of 1999?" presented at the California Energy Markets conference, San Francisco, October 1999.

20. "New Policies at the California ISO" presented at the Association of Bay Area Governments conference, Oakland, November 1999.

21. "RTO's in the Western Region," presented as keynote speaker for the Power Association of Northern California, March 2000.

22. "RTO's: Reinventing the Grid", presented as panelist and moderator at National Gas Intelligence conference GasMart 2000, Denver, April 2000.

23. "Trading's Future: Reading the Tea Leaves", presented at the Platts News Energy Service conference on Day of the Trader, New Orleans, October 2002.