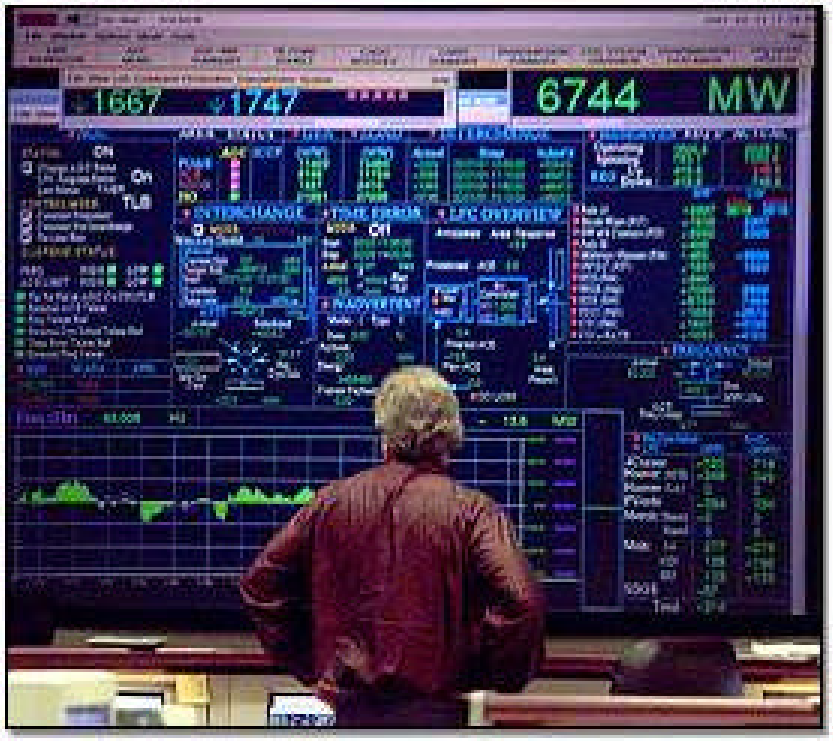
PREVENTING MARKET FAILURES ON THE ROAD TO COMPETITION

Analysis & Recommendations of the Electricity Consumers Resource Council



A Special Report

ELCON

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INTRODUCTION

More than half the states have approved the introduction of retail competition in their electricity markets, including the deregulation of generation and some other previously regulated utility services. Retail customers in several states now have the opportunity to switch suppliers, and competition in some regional wholesale markets continues to evolve and mature. But all is not well.

In California, one of the first states to proceed down this path, the wholesale market collapsed because new generating resources were not added in Western markets to keep pace with demand growth. California's unique market design—intended to allow utilities to recover their stranded costs during a four-year transition period—proved to be a huge liability when the supply shortfall, and other contingencies, emerged. The California crisis is two-fold: it is a crisis of supply with the risk of widespread rolling blackouts now almost a daily occurrence, and it is a financial crisis that subjected two huge utilities to an unprecedented price squeeze. As result, California ratepayers face the specter of unparalleled rate increases. The crisis has created an unfortunate perception that deregulation or industry restructuring is not working, is ill conceived, and perhaps should be reconsidered or abandoned.

The reality is that the merits of deregulation and restructuring have not been disproved because the requisite market structures are not yet in place—in California or elsewhere. States have been uniformly cautious with their restructuring efforts, and their initial priorities have not always been to establish competitive markets for electricity as soon as possible. Instead, states like California established a transition period that was strictly preparatory and should never have been confused with the desired end state.

California and other states will not arrive at the desired end state without committing to further changes and midcourse corrections to their preliminary market design to ensure that the objectives of a competitive power market are achieved. In that context, ELCON offers to regulators and other policy makers a series of recommendations intended to prevent additional market failures from occurring. Many market design features adopted in California were copied by other states (*e.g.,* retail rate freeze). Recommendations are offered for each of 24 separate issues that create, prevent, or deal with market failures, or ensure that competitive electricity markets have a fair chance of being successful.

SUMMARY

The California crisis has renewed an on-going debate over the optimal design of a competitive electricity market. As a matter of practical reality, ELCON believes that market power—horizontal, vertical, and localized—will remain a problematic impediment to efficient market formation and operation, perhaps indefinitely. Policy makers in the United States are not likely to mandate the structural adjustments necessary to adequately eliminate market power in the electric industry.[1] Nonetheless, this fact should not be used as an excuse to delay further restructuring. ELCON remains committed to electric industry reforms that allow competitive retail and wholesale markets to be established for the benefit of all consumers. But the problems posed by residual market power must limit the options available to policy makers in the initial market design, and any subsequent midcourse corrections, to market structures that are most resistant to market power abuse.

Causes of Market Failure

At least nine factors have contributed to market failures in California and elsewhere:

- Gaming behavior of suppliers and load serving entities
- Flawed markets for capacity
- Generation divestiture and the absence of vesting contracts
- Unnecessary centralized power exchanges or pools with single-price auctions
- Retail rate freezes
- Improperly designed stranded cost recovery mechanisms
- Provider of last resort (POLR) service
- Unforeseen consequences of conservation and energy efficiency programs
- Inflexible air emissions standards

Some of these factors, by themselves, are relatively benign, but in combination with other factors create serious financial or reliability consequences. All regions of the country are at least partially vulnerable to some or all of these factors. Many of these factors were the result of political compromises intended to protect stakeholders from the consequences of restructuring (*e.g.,* retail rate freezes, stranded cost recovery, and POLR). The essential lesson from California is that market design should abide by time-tested economic principles and not political influences.

Some market structures (*e.g.,* centralized exchanges with uniform-price auctions, or centralized pools with optimized dispatch) are more vulnerable to the market power of suppliers and therefore create greater risk of market failure. These structures should be avoided. Market designs that allow more decentralized market structures, such as those

[1] ELCON has prepared a position paper outlining the structural changes necessary to eliminate market power. See *Profiles in Electricity Issues: Eliminating Market Power in the Transition to Competition,* July 1999. A copy can be downloaded from ELCON's website at: www.elcon.org/profiles.htm.

that maximize the use of forward contracts in bilateral markets, are more resilient to potential market power and offer the greatest protection to consumers.

But no competitive market can operate without both supply and demand integrated within the same market. Restructuring efforts to date have almost exclusively focused on "wholesale-only" markets as the *initial* market structure. This is a critical mistake and poses the greatest risk of market failure. The emerging dominance of a few large suppliers—particularly affiliated marketers with relatively large portfolios of physical generating assets—is not conducive to efficient "supply-on-supply" competition given the unwillingness or inability of regulators and antitrust agencies to take all necessary remedial actions to mitigate market power. It is essential that *demand* be engaged to check the growing ability of any supplier by itself, or with other suppliers, to profitably maintain prices above competitive levels.

Preventing Market Failures

At least six factors can prevent market failures during the transition to competitive markets:

- Appropriate transition period design
- Markets for price-responsive customer loads
- Maximizing use of all available resources including QF capacity
- Maximizing use of forward contracts
- Ongoing market surveillance
- Enforcement of short-term reliability on a nondiscriminatory basis

Markets during a "transition period" should never be confused with the real thing. Arguably, the transition period requires greater regulatory oversight and regulatory "activism" than before or after the transition. All else equal, transition periods should be brief to minimize opportunities for gaming of the initial market structure (with potential loopholes) by incumbent or new market participants. An essential requirement of the transition period is the establishment of effective market surveillance functions in both retail and wholesale markets. Independent market monitors are needed to evaluate the progress of competition and to recommend necessary midcourse corrections to market design, the stranded cost recovery mechanism, POLR, or other market rules.

Markets—not *programs*—for price-responsive customer loads should be established under the auspices of each FERC-approved RTO. This service should be structured as a new FERC Order 2000 "Function 9" to ensure that markets for customer load response, or CLR, are efficiently integrated with the other RTO real-time markets and standardized.

PURPA-qualifying facilities (QFs) such as industrial cogenerators and small power producers have become a significant resource in almost all regions of the country. Yet, these plants operate under restrictions that are not imposed on traditional utility resources for the obvious reason that QFs compete with utility resources. In California, the risk of rolling blackouts increased because QF capacity was shutdown due to maltreatment by utilities and state regulators.

Short-term markets are inherently volatile and risky, but that is their function in competitive markets. Market designs should not encourage or force short-term markets (*e.g.,* day-ahead or day-of exchange or pool-based markets) to be the dominant market. Forward contracts in bilateral markets are necessary to cultivate competitive behavior and protect consumers from supplier market power.

The reliability operating standards of the North American Electric Reliability Council (NERC) were designed for a totally regulated industry. These standards must be rewritten to conform to the new industry model and prohibit any market participant from using such standards for its commercial advantage.

Dealing With Market Failure

Market failures have occurred in California, Alberta, the Midwest (in 1998), and elsewhere. Some are severe and ongoing, but others were short-lived events. At least four factors can remediate market failures:

- Application of market "circuit breakers"
- Bankruptcy
- Emergency siting authority
- Market stabilization plan

Runaway prices are endemic of markets that suffer from chronic scarcity (*e.g.,* California and Alberta). This is a market failure, and free-market purism should be abandoned in favor of reasoned corrective actions to stabilize and rectify market flaws. State officials and federal regulators may need to develop market stabilization plans for correcting such flaws and restoring confidence in the market. This includes the imposition of circuit breaker-type price caps to prevent a total market collapse. Other forms of price caps intended to suppress price volatility or "re-regulate" the market should not be pursued.

When a market failure has brought a regulated utility to the verge of bankruptcy, protection under the federal bankruptcy laws should always be an option if the alternative is to simply recover all costs—prudent or not—from ratepayers, and absolve any of the utility's creditors of mutual culpability. If no one is to blame, all market participants bear the burden to share the costs of any market failure.

Under situations of chronic supply scarcity, federal and state authorities should identify and encourage any measures that streamline or expedite the siting and permitting of generating capacity, including limited waivers of air and water quality standards and land-use restrictions. Such actions may be necessary to avoid the risk of major power outages. Widespread power outages can exact huge economic costs and have sparked looting and rioting in the past.

Ensuring Competitive Markets

At least six factors are necessary for ensuring competitive markets:

- A bilateral market structure with tradable physical transmission rights
- Fair and nondiscriminatory new generator interconnection rights
- Adequate natural gas infrastructure
- Adequate new generation and fuel supply
- Adequate transmission capacity
- Large, independent RTOs

Several of these factors should be self-evident and were equally important under the traditional regulatory regime (*e.g.,* natural gas infrastructure, and new generation and transmission capacity). The other factors are essential prerequisites for a competitive electricity market. All of these factors need to be addressed before the commencement of and during the transition period.

Establishing competitive markets in formerly regulated industries is a daunting task. But it has been done in many other industries of equal complexity. Regulators and policy makers should take encouragement from that legacy and proceed to restructure the "last great monopoly." Consumers deserve no less.

CAUSES OF MARKET FAILURE

1. GAMING BEHAVIOR

Gaming can be considered any business behavior that exploits weaknesses or flaws in the market design, and that produce market results that are inconsistent with the objectives of the market design (*e.g.,* efficiency, competition, no undue discrimination, or reliability), while not being in violation of a tariff or market rules. In other words, gaming is behavior that would not have been permitted or possible under a tariff or market rules, had the designers of the tariff or rules anticipated the behavior and were able to preclude it from being exercised in the first place.[2]

There are all kinds of potential gaming behaviors in transitional markets with new forms being tested all the time by dominant market players. Most forms of gaming are associated with the economic or physical withholding of generation or transmission. The market power implications of these behaviors are just now being evaluated and understood. Two forms of gaming are discussed below.

Under-Scheduled Load

As soon as the restructured California market began operation in 1998, gaming of market loopholes was evident.[3] Initially, the California market was intended as a transitional market to allow the three major investor-owned utilities to recover 100% of their stranded costs. The mechanism chosen for stranded cost recovery included the establishment of a central "power exchange," a retail rate freeze, and a statutory mandate that the utilities sell all of their generation into the power exchange and buy all their native load or Provider of Last Resort (POLR) requirements (except for ancillary services) from the exchange. The difference between the power exchange clearing price and the frozen retail rate (by rate class) defined the "competitive transition charge" (CTC) paid by ratepayers within a particular retail class to settle the utility's stranded cost claims.

Each utility was allowed to procure ancillary services (A/S) in a separate market operated by the California Independent System Operator or CAISO. It was intended that the utilities would procure no more than about 5% of their needs in the CAISO's A/S markets. Instead, the utilities gamed the two markets and began "leaning" on the CAISO's ancillary services market for 20 to 30% of their needs in order to inflate their recovery of stranded costs. By sharply reducing demand in the power exchange (by under-scheduling each utility's expected load), the power-exchange clearing price was artificially reduced. This increased the spread between the exchange price and the frozen retail rate. But, by excessively leaning on the CAISO's A/S markets, the utilities

[2] This definition of "gaming" is adopted, almost verbatim, from: James F. Wilson, "The Regional Transmission Organization's Role in Market Monitoring," Navigant Consulting, Inc., Prepared for the Edison Electric Institute, August 18, 1999.

[3] Market Surveillance Committee of the California ISO, "Preliminary Report on the Operation of the Ancillary Services Markets of the California Independent System Operator (ISO)," August 19, 1998.

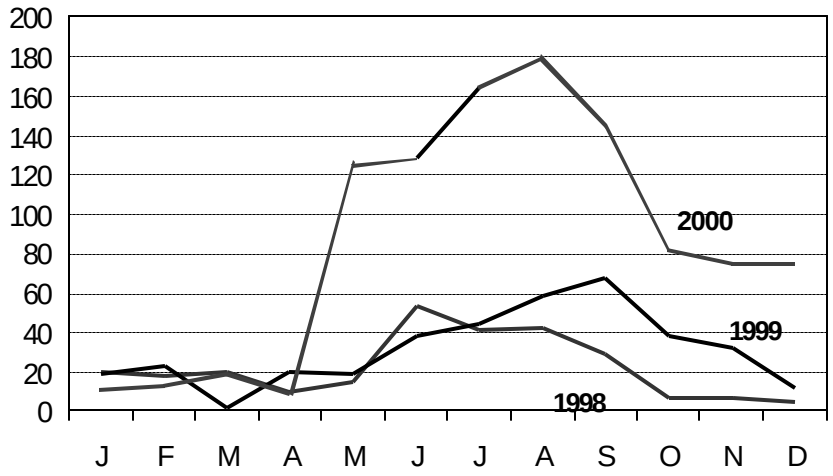
reduced the CAISO's margin of error for ensuring the reliable operation of the CAISO's control area and the security of the Western Interconnection.

Inadvertent Interchange

Related to the under-scheduling of load, is a phenomenon called Inadvertent Interchange but more commonly known as "leaning on the interconnection." Examples of this were reported to the NERC Board of Trustees on February 7, 2000.[4] The report noted that "[s]everal control areas were found to be 'leaning' on the Interconnection, but none as seriously as CINergy. CINergy's Inadvertent Interchange ranged from 79 MW to 1656 MW over the nine hours, averaging over 1000 MW." Inadvertent Interchange is when a control area operator—knowingly or unknowingly—takes advantage of unscheduled energy from the Interconnection, *i.e.,* sells energy in excess of the output from their own generation resources plus what they purchase from others. If a control area operator deliberately does this, it is, in effect, stealing power.

NERC standards are supposed to prevent Inadvertent Interchange, but compliance with NERC standards is strictly voluntary. "Leaning" poses several risks. First, it reduces the frequency throughout the entire interconnection. This can severely damage generators and at certain threshold frequency reductions result in load shedding to prevent generators from tripping. Second, inadvertent flows are phantom flows, *i.e.,* they are not known to NERC Security Coordinators who are responsible for monitoring power flows. If such a flow overloads a transmission facility, there is no way to curtail the flow to prevent potential damage to the transmission line.

Transmission Loading Relief, 1998-2000
(Level 2 or more)



[4] North American Electric Reliability Council, *1999 Summer Post-Seasonal Assessment,* (Princeton, NJ: North American Electric Reliability Council, 1999)

Overselling Transmission

Transmission customers pay for transmission service whether it is used or not. Customers pay to *reserve* the right to schedule a transaction, and should subsequent events or circumstances prevent them from actually scheduling the transaction, or should a transaction be subject to curtailment, they are still obligated to pay the transmission provider. This situation creates a powerful economic incentive for transmission providers to deliberately *oversell* transmission capacity. These providers rely on NERC-certified Security Coordinators to invoke Transmission Loading Relief (TLR) procedures to curtail enough transactions to prevent all the transactions from going physical. The graph on the previous page shows the rapidly escalating number of TLRs since 1998. If this trend continues, the impact on market operation and reliability of the Eastern Interconnection could be catastrophic.

RECOMMENDATIONS:

- The independent Market Monitoring units or MMUs assigned to each regional transmission organizations (RTOs) should be authorized to search for evidence of gaming behavior in wholesale bulk-power markets, and recommend market design or rule changes to eliminate the behavior.

- When a RTO has implemented any NERC reliability standard or business practice, the "market interface" between such standard or business practice, and the fair and efficient operation of the wholesale bulk-power markets, should be subjected to the same market surveillance standards as other RTO market rules and procedures.

- MMUs should be careful and not identify certain forms of appropriate trading behaviors (*e.g.,* arbitrage) as attempts to unfairly game the market.

- Congress is urged to enact legislation requiring the establishment of a new North American electric reliability organization subject to FERC oversight. The new organization would have the authority to force compliance with its standards.

2. CAPACITY MARKETS & RESERVE REQUIREMENTS

Absent price-responsive load in the wholesale spot markets, some existing ISOs ostensibly created a market for capacity that often allows generators to be paid twice for the same product. In California, this feature was easily gamed in the CAISO's market for replacement reserves after a suppliers' market emerged. The need for a capacity market is only justified in markets where there are barriers to entry for price-responsive load.

A capacity market is a vestige of the old regulated industry where all retail loads were captive and served on a coincident basis under average rates. Capacity reserve margins were maintained to hedge against a combination of demand uncertainty and price inelasticity. These requirements have been readily adopted or mandated in new "wholesale-only" markets but are, in fact, a form or re-regulation. Capacity markets also tend to neuter price volatility, defeating an important attribute of competitive markets.

The alleged need for a separate market for capacity is a good measure of an imperfect market and the failure to adequately develop price-responsive load resources in real time, an original intent of industry-wide restructuring. Capacity reserve requirements have also been proposed for Load Serving Entities (LSEs) that are tasked as "providers of last resort" or POLR. Many generators that would serve such markets actively encourage their formation and seek to limit competition from retail customers that are willing to bid their load into the real-time markets (*e.g.,* with Customer Load Response (CLR) service).

Finally, in markets with ongoing recovery of the stranded "fixed" costs associated with some generating assets, this recovery process, in parallel with capacity markets, is creating some serious economic distortions. This results from the fact that the owners of these assets are effectively recovering their fixed costs more than once.

RECOMMENDATIONS:

- The retention of limited capacity reserve requirements in a transition period to a more fully competitive market is justified to the extent that significant portions of retail load are served by Providers of Last Resort (POLR), and as a hedge against unforeseen consequences of new market structures. However, this should be explicitly recognized as an indicator of market failure, and not as a necessary feature of an end-state competitive market. Such requirements should be reduced and, quickly eliminated, as retail load gravitates to alternative competitive suppliers.

- Transitional "reserve" markets should be operated by independent RTOs in conjunction with their ancillary services obligations under FERC Order 2000 and the compelling need to allow retail customers to bid their price-responsive load into the wholesale spot markets.

- Price-responsive load bids should have first call in any transitory RTO capacity markets (*e.g.,* operating reserves), and as markets for CLR and other forms of price-

responsive loads develop, the RTO should phase out and limit access to any existing capacity markets.

- Where capacity markets continue to exist, those markets should be restricted to new capacity resources.

- Generators should not be burdened with the expense of maintaining "reserve" margins. This is not their appropriate role in a competitive market. The management of supplier risk is the responsibility of the Load Serving Entity (LSE), whether it owns generation or not, or the customer.

3. GENERATION DIVESTITURE & VESTING CONTRACTS

One objective of industry restructuring is to force utilities and other suppliers to identify and focus on core competencies. Attempting to retain within a holding company, both regulated and unregulated business functions, requires extraordinary justification under normal best business practices.

As industry restructuring proceeds, utilities are increasingly divesting assets to reposition themselves in a more competitively driven industry, based on its (and their financial advisors') perception of the prevailing economic incentives. For example, some utilities are exploring the limited spin-off of transmission assets (to form a for-profit RTO or independent transmission company) to take advantage of potentially lucrative performance-based regulatory incentives promised in FERC's Order 2000. But more commonly, utilities are shedding generation assets in order to focus on their "wires" business because the risk of an unregulated generation business is significantly different (and greater) than the regulated T&D business, requiring a different management style and strategy. From a shareholder perspective, these differences are best accommodated in separate corporations.

This reorganization of assets is generally positive and contributes to the unbundling of operating functions and products and services, a necessary pre-condition to a competitive market structure and the mitigation of potential market power. However, real competition will not exist during any state-imposed transition period when stranded cost recovery and other priorities prevent a real market from forming. It is therefore necessary to depart from strict market principles during a transition period to ensure that the interests of customers are protected because the market is not yet able to provide those protections.

In California, generation was divested without vesting the output of those assets with the customers that remained captive to the assets' former owners. To compensate for the error, the State's Governor proposed a requirement that PG&E and SCE be prohibited from divesting their remaining hydroelectric and nuclear generation, and to sell all power from those units to the utilities' customers for ten years at cost-based rates.

RECOMMENDATIONS:

- When rate-based generation is deregulated and divested, the output of those assets should be secured under vesting contracts with the original owner(s) to ensure that any remaining captive customers are served under cost-based rates.

- Vesting contracts between new and original owners of generation should be retired as retail customers begin to switch suppliers, and in proportion to the amount of retail load that is served by new suppliers.

- Any restrictions on the divestiture of generation should be terminated when workably competitive markets have been established.

4. POWER EXCHANGES, POOLS & AUCTIONS

Power Exchanges & Centralized Pools

California required the creation of a centralized power exchange, the Cal PX, to facilitate the recovery of stranded costs during a four-year transition period. The *Competition Transition Charge (CTC)*, the amount of stranded costs recovered from each ratepayer, was calculated by subtracting the Cal PX clearing price from the applicable retail rate which, under state law, was frozen over the same four-year transition period or until the utility recovered its stranded costs, whichever came first.

The state's three investor-owned utilities were also required to bid all their generation into the Cal PX and to purchase all their requirements (as Providers of Last Resort) from the same exchange (except for ancillary services that were provided by the CAISO). The power exchange subsequently became the focal point for several examples of market failure that might have been avoided had no exchange existed in the first place. The Cal PX is no longer operational as a result of FERC actions.

Previously, in England and Wales, government regulators also ordered the abolishment of a central exchange (the "Pool") because problems with horizontal market power of generators proved intractable. As of March 27, 2001, the market in England and Wales is based on bilateral trades. A System Operator procures generation services (equivalent to "ancillary services" in the U.S.) to balance the system loads and generation, manage congestion, and maintain reliability. Settlement is based on generator "incs" ("Offers") and "decs" ("Bids") that are accepted in the near real-time market. Independent power exchanges are expected to provide the main trading platforms for the new market. These exchanges would enable market participants to refine their contract positions close to real time in response to weather and other market variables.

The establishment of a mandatory (as previously in California and the U.K.) or quasi-mandatory (as in Alberta, PJM or New York) power exchange can create market conditions that allow generators to easily exercise market power unless regulatory and antitrust agencies are extremely diligent in eliminating market power. But there is no precedent in modern times for the necessary level of diligence given the fact that the Sherman and Clayton Acts are generally weak and ill-suited for modern corporate structures, and producers can often exert undue political influence making regulatory remediation equally ineffective. The perceived benefits of mandatory or quasi-mandatory exchanges do not outweigh this risk.

While centralized exchanges pose clear market power risks, independent, private exchanges (typically structured as Web-based auctions/reverse-auctions where buyers and sellers mutually agree on as-bid offers) have an important role in competitive electricity markets. They are strictly voluntary and provide nearly the same negotiating flexibility in short-term markets as long-term bilateral, forward contracts. Independent exchanges are also less likely to be targeted for market power abuse.

Auctions Formats in Exchanges & Pools

Any regulatory or statutory requirement to establish a centralized power exchange forces a concomitant decision on the type of auction used for establishing the market-clearing price. This has provoked intense debate between the perceived theoretical merits of the *Uniform-price Auction* (including a variant based on the *Vickrey or Second-price Auction*), and the costly effects of this auction format on any exchange subject to market power. Unless the generation markets are absolutely free of horizontal market power, any auction format that rewards all successful generators the same highest bid (or highest rejected bid) is a windfall to the generators. Except for the generator submitting the winning bid, this auction format provides few economic incentives to the vast majority of the generators that will simply bid "zero" and take the "market-clearing" price. This creates a market that makes it easy for generators to make money, but that is equally costly for consumers.

To prevent such windfall profits, some stakeholder groups and policy makers advocate the *Discriminatory Auction* format in which all winning bids are accepted as bid. While arguments against the use of *Discriminatory Auctions* rely on theoretical conjectures of changes in bidding behavior under different auction formats, it is widely acknowledged that empirical evidence of the superiority of *Uniform-price Auctions* is "inconclusive."[5]

RECOMMENDATIONS:

- Mandatory (or quasi-mandatory) exchanges and centrally dispatched pools are highly susceptible to horizontal market power abuse and this risk is not offset by any compelling benefits that only centralized exchanges or pools provide. Competitive markets for electricity should be established without any direct or indirect government mandate for centralized power exchanges or pools. This should not preclude free entry into a market of any independent, private exchanges.

- Any RTO with an approved central exchange or pool (*e.g.,* in LMP-based markets) should reject the use of *Uniform-price Auctions* as the mechanism for establishing a single market-clearing price. The theoretical benefits of this auction format do not outweigh the potential costs associated with horizontal market power in generation markets.

- So-called "hybrid" market structures, with a centralized exchange (*i.e.,* LMP) structure in the near real-time market and bilateral contracts in the forward markets, and which are under consideration by several RTOs, should be tested. Market power problems in the near-term exchange will likely emerge if this market structure is deemed incapable of providing adequate liquidity. This would be an important lesson for going forward.

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[5] See, for example, Catherine D. Wolfram, "Electricity Markets: Should the Rest of the World Adopt the UK Reforms?" Program on Workable Energy Regulation (POWER), University of California Energy Institute, PWP-069, September 1999, page 10.

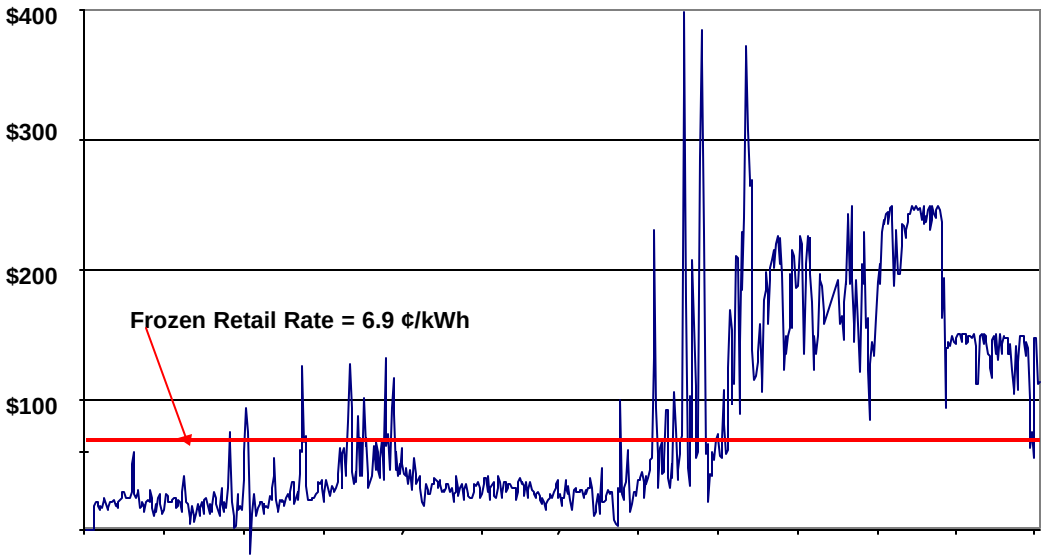
5. RETAIL RATE FREEZES

The stranded cost recovery mechanism adopted in California never anticipated spot market prices (on the Cal PX) exceeding the level of frozen retail rates. In any event, that risk was placed on the utilities. When the demand began to exceed supply on a chronic basis, pushing the PX price above the level of frozen retail rates, the utilities were caught in a dangerous price squeeze.

When San Diego Gas & Electric Company's rate freeze was lifted, the utility's retail customers were exposed to the price risk of the spot market without any viable options

CAISO Imbalance Energy Price vs. Retail Rate

March 1999 – March 2001, Dollars per MWh



Source: California ISO, 2001

for hedging that risk. The California "crisis" began in June 2000 when high PX and ISO prices were passed through to SDG&E customers and customer bills doubled or tripled.

Rate freezes are common in many states that have restructured their utilities. Utilities and/or customers in those jurisdictions may not be immune from similar price squeezes.

RECOMMENDATIONS:

- Retail customers should not be exposed to wholesale spot market price volatility unless and until the market provides customer choice and adequate hedging services.

- Policy makers should carefully review the consequences of any rate cap or rate freeze proposal before mandating such action.

6. STRANDED COST RECOVERY MECHANISMS

The transition to competitive electricity markets might have been easy without the added baggage of stranded cost recovery, but the original problem—substantial utility investments and expenses (capitalized as "regulatory assets") at above-market costs—triggered the need for restructuring in the first place.

Stranded cost recovery defines many of the parameters of the transition period. But, as California has unwittingly demonstrated, an inappropriate stranded cost recovery mechanism can make the transition period inoperable.

Initially, the California market was intended as a transitional market to allow the three major investor-owned utilities to recover 100% of their stranded costs. The mechanism chosen for stranded cost recovery included the establishment of a central "power exchange," a retail rate freeze, and a statutory mandate that the utilities sell all of their generation into the power exchange and buy all their native load or Provider of Last Resort (POLR) requirements (except for ancillary services) from the exchange. The difference between the power exchange clearing price and the frozen retail rate (by rate class) defined the *Competitive Transition Charge (CTC)* paid by ratepayers within a particular retail class to settle the utility's stranded cost obligations. In other words, to earn the right to switch suppliers, the customer had to sharing *all* the net benefits from switching with its previous utility supplier. This recovery mechanism eliminated any economic incentive to switch suppliers during the mandated four-year transition period, except for customers who choose to pay above-market prices for "green" power alternatives.

Stranded cost recovery is a necessary accommodation to advance industry-wide restructuring at a reasonable pace. Few states will have the luxury to restructure its utilities without this accommodation. But it is important that the stranded cost recovery mechanism be as benign as possible to avoid contributing to a market failure.

RECOMMENDATIONS:

- State regulators should be careful in their choice of a stranded cost recovery mechanism to avoid any unintended consequences. The recovery mechanism should not be allowed to directly interfere with market operation, or depend on market operation to determine the amount of a utility's recoverable costs. Stranded cost recovery should be limited to the utility's undepreciated balances net of any capital gains on other assets.

7. PROVIDER OF LAST RESORT (POLR) SERVICE

Provider of Last Resort (POLR) service is usually required in states that have implemented retail choice. It is often called Supplier of Last Resort service. Another variation of this service is Default service. A Provider of Last Resort is that supplier of electricity that is responsible for providing generation service in those instances where a customer is otherwise without service (including for non-payment). More specifically, retail customers who are no longer able to purchase electricity from a retail provider of choice through failure of the retailer or severance of the relationship by the retailer and have not selected a replacement retailer, or who cannot obtain regular electricity services from any retailer, or who choose not to leave their utility ("choose not to choose"), are eligible for POLR service. Most states require local utilities to be POLRs.

The obligations of the POLR and the customer taking POLR service differ from state to state, but generally the service is structured to resemble traditional bundled service at a fixed, cost-based rate. The service is very similar to the "assigned risk plans" that were used in certain insurance markets (*e.g.,* worker compensation and automobile insurance), and which have since been abandoned in that industry.[6]

As more and more states gain experience with retail choice, some glaring problems have emerged with POLR service.[7] These include: (1) the creation of a market distortion in which customers or marketers can game the POLR service vis-à-vis the wholesale spot markets; (2) suppression of customer awareness of price signals; (3) discourage the market for long-term contracts that would otherwise provide for customer hedging; and (4) prevent incumbent utilities from becoming "wires" companies because they must remain in the business of supply risk management. Each of these problems emerged in California and elsewhere, resulting in either the utilities or its customers being placed in a price squeeze.

RECOMMENDATIONS:

- POLR service should not provide an economic incentive to stay out of the market for any customer that is financially capable of choosing alternative retail suppliers. States should reconsider the consequences of retail rate freezes and the implications of such freezes on market development.
- States that require some form of POLR service, because not all retail customers are eligible or willing to shop at the same time, must ensure that vesting contracts are established between the new owners of generation that was divested by any POLR, and the POLR, to prevent retail customers from being "thrown" into the wholesale spot market.

[6] Roger D. Colton, "Provider of Last Resort: Lessons from the Insurance Industry," September 1998.

[7] Frank C. Graves and Joseph B. Wharton, "POLR and Progress Towards Retail Competition – 'Can Kindness Kill the Market?'" Presentation Before the NARUC Winter Meetings, The Brattle Group, February 27, 2001.

8. CONSERVATION & ENERGY EFFICIENCY PROGRAMS

The crisis in California unequivocally demonstrated that state-sponsored conservation and energy efficiency programs could not eliminate the need to build new generating capacity to meet demand growth. No state invested more ratepayers' money toward the promotion of conservation and energy efficiency programs than California, with funding mechanisms authorized by the California Public Utilities Commission. This includes the investment in renewable energy resources such as solar, geothermal, and wind generation when other resources were obviously more cost effective.

Unfortunately, the promotion of conservation and energy efficiency programs often created a false impression that such programs could obviate the need for any new traditional generating resources. Often lost in the public debate created by the California power crisis is the fact that electric industry restructuring was partially predicated on the failure of the central-planning approach to regulation that relied exclusively on least-cost planning (LCP), integrated resource planning (IRP), and demand-side management (DSM) programs to meet the basic energy needs of the consumers. It is no secret that the states that most zealously pursued these programs were the states that ended up with the highest retail electric rates and stranded cost claims.

Nonetheless, conservation and energy efficiency measures are important activities and competitive markets will promote such efforts. In fact, competitive markets are a superior forum for determining the true cost-effectiveness of any conservation or energy efficiency investment. But under the best of circumstances, conservation only delays the need for new generation as long as population and the demand for electricity keep growing.

RECOMMENDATIONS:

- States always have the discretion to promote the efficient use of any natural resource, including energy. However, any state program to encourage conservation and energy efficiency should avoid creating false promises that mislead the public into believing that basic necessities are obtainable with little or no cost, and without the need to balance those objectives with other societal goals such as a clean environment and economic growth.

- The costs of any state-sponsored conservation and energy efficiency program should be borne by the consumers that directly benefit from such programs. All forms of taxation or subsidies that finance such programs, in whole or in part, should be subject to public disclosure and debate, and not hidden in arcane regulatory accounting procedures that deliberately evade public scrutiny and accountability.

- The efficient production and allocation (*i.e.,* usage) of any energy resource is best achieved in fully competitive markets. End-use consumers will maximize considerations of energy efficiency in their purchasing and investment decisions only

in markets that fully compensate them for the actual cost savings they create by their actions.

9. AIR EMISSIONS STANDARDS

Generators are required to obtain emission offsets to operate in regions of the country that are not in attainment with federal air quality standards, or for new sources that may cause non-attainment. The pollutants typically associated with new fossil-fueled power plants are NO_X, VOC, PM10, SO_2, and CO. Emission Reduction Credits (ERCs) are the verifiable historic emission reductions that can be used to offset a new power plant's emissions. ERCs are tradable and where available are sold at a market-determined price. In California, the cost of an ERC (*e.g.,* a NO_X ERC in dollars per ton in 1999) may vary from a low of $913, a high of $45,000, and an average of $13,884 in the same year. However, in some markets the limited availability of ERCs—at any price—may prevent construction of new power plants. This problem restricts the use of existing stand-by generation and discourages the development of new distributed generation (DG).

Plant operators are sometime allowed to use various offset strategies to secure project permitting. These strategies include inter-pollutant, inter-sector, and inter-district/basin trading. Each of these trading strategies involves a trading ratio to account for the effect of various strategies.

The need to increase electric supply in the short run (*i.e.,* keep plants running) may also delay new retrofits that would reduce the emission credits needed to operate the plants in the long run. The inflexibility inherent with existing air quality regulations creates a dilemma for a plant operator who is forced to tradeoff the prospect of an electrical outage with the production of future ERCs.

Certainly, air quality concerns are valid, but so are countervailing economic costs associated with higher power costs and outages, and the risk to safety and public welfare. The two concerns need to be balanced. During power emergencies, the emission caps should be carefully relaxed to allow adequate short-term supply and to give generators the flexibility to plan for maintenance and retrofits.

RECOMMENDATIONS:

- Federal and state air quality laws should be rationalized with the broader societal and economic needs, including reforms that give states more flexibility to comply with federal standards. Absent broader reforms to applicable federal and state laws, each jurisdiction should waive requirements to the extent it has authorities to do so.

- All emission standards should meet a cost-benefit test that properly balances environmental objectives with the broader societal and economic needs.

- Air emissions permitting regulations should provide for greater flexibility in the manner in which offset strategies are allowed, such as inter-pollutant, inter-sector, and inter-district/basin trading. Limited exemptions from established trading ratios should be allowed during periods of power emergencies.

PREVENTING MARKET FAILURES

1. TRANSITION PERIOD DESIGN

The transition from a highly regulated industry to a less regulated industry—when tools for market power mitigation are less than perfect—has to be arduous and artificial. The transition period is only a transition, and not a time for either free-market purity or unbending regulatory rigor. As such, expectations during the transition period must be tempered by structural adjustments necessary to allow competition to work, particularly the disposition of stranded costs. Many of the early states, like California, were high-cost states, with huge stranded cost obligations. The final settlement of such costs creates an unavoidable barrier to real competition.

Several attributes of transition period design are necessary. These attributes are: (1) the duration of the transition period; (2) the amount of stranded costs deemed recoverable from ratepayers and the mechanism devised to recover such costs, including requirements that the utility mitigate some portion of these costs; (3) the assignment of responsibility for Provider of Last Resort (POLR) service; (4) treatment of previously rate-based generation that is divested; (5) the need for a retail rate freeze or cap; and (6) the mechanism chosen to expose the generation commodity (and other potentially competitive services) to retail competition.

In 1996, California adopted a relatively short, 4-year transition period to commence in 1998.[8] The original intent was to shorten the transition and accelerate the onset of a "date certain" when real competition would be feasible. This short transition meant that customers would have to pay relatively high ("non-by-passable") stranded cost charges (or "competitive transition charge"). This, coupled with the fact that the CTC was almost defined as the net savings a customer was supposed to receive by switching supplier, killed even the pretense of retail choice in the California market.

Other states, notably Pennsylvania, opted for longer transition periods (typically via settlements with each utility) with a less onerous stranded cost payment requirement during the transition period.

Like the choices for a home mortgage, California opted for a high payment, short mortgage period, while Pennsylvania opted for smaller payments stretched over a longer payment period. This is certainly a legitimate policy choice that states confront. Under the best of circumstances, the transition period will only allow a "constructed" market to operate as each essential feature of competition is gradually established. The so-called "Day One" of competitive markets is, by definition, the last day of the transition period. In California, policy makers and public alike were convinced that Day One was March 31, 1998, and not March 31, 2002.

[8] While California's restructuring legislation was enacted in 1996, the basic attributes of the transition period (and other pre-conditions to restructuring) were codified in a September 11, 1995 "Memorandum of Understanding" prepared by the Southern California Edison Company (SCE) and supported by many California stakeholder groups.

RECOMMENDATIONS:

- Reasonable Expectations – State regulators and policy makers should be candid with the public regarding the existence and limitations of a transition period. The full benefits of competition will only be realized *after* competitive markets are established, not *before* such markets are fully established and mature.

- Monitor Retail Markets – State regulators should establish independent market monitoring functions within their agencies to monitor the progress of retail competition and to recommend any necessary midcourse corrections to market design, to the stranded cost recovery mechanism, or to other market rules and procedures.

- Focus on the Long-run – As part of the transition period design, state regulators should ensure that the following long-term issues are adequately being addressed under state policy to support competitive electricity markets: (1) bilateral markets; (2) interconnection rights of new generating resources; (3) natural gas infrastructure; (4) new generation, and fuel supply and diversity; (5) new transmission capacity; and (6) regional transmission organizations (RTOs).

2. MARKETS FOR PRICE-RESPONSIVE CUSTOMER LOADS

Every competitive market requires a "demand side" that allows end-use customers to selectively enter the market based on the each customer's individual price responsiveness and opportunity costs. This creates the classic downward sloping demand curve that illustrates the theoretical principle that as price increases, quantity consumed (*i.e.,* demand) decreases, all else equal. No customer is ever forced to enter a competitive market in a prescribed manner (*e.g.,* purchase only in a mandatory exchange).

During the mandatory 4-year transition period in California, retail access was deliberately restricted because of the nature of the *Competitive Transition Charge* (CTC), the mechanism used for stranded cost recovery. This discouraged customers from opting for retail choice and demand-responsive load never emerged in the market. In addition, special utility and ISO programs that attempted to encourage demand bids from large customers failed because: (1) the programs were ill-conceived, (2) were deemed punitive by customers, and (2) price caps eventually eliminated any economic incentive to enter this market. Thus, an important resource was artificially kept out of the market at times when it was essential to get every possible resource in play to prevent outages. California and other states are now grappling with how to restructure their markets to incorporate demand responsive loads.

Wholesale-Only Markets

Almost all new competitive electricity markets were structured (by intent or not) as "wholesale only" markets, in which all demand (customer loads) remain aggregated and served on a coincident basis just as it was for almost a hundred years of regulation. Such markets are fraught with risk if generation markets are concentrated and able to exercise market power. This was certainly the situation in California's markets begin in 2000 when demand began to routinely exceed supply.

There is considerable confusion in the public debate on retail restructuring regarding the proper role of retail loads in competitive markets. For example, some advocates recommend that all retail loads, or all large loads, be forced to buy from the wholesale spot markets unless otherwise hedged with "contracts for differences." This, they argue, would ensure demand responsiveness in the market and mitigate price volatility.

But this is *not* real competition. In every other spot commodity market, "retail" consumers are totally absent from the market (except, for example, as investors of futures contracts or speculators). "Demand response" in these markets is provided by wholesale entities (including large manufacturers) or market intermediaries. Only a fraction of total demand may be active in these spot commodity markets, with most purchases from producers locked in forward contracts, but entry is always voluntary and normally limited to players with particular skills in understanding and managing price volatility and risk. Costs in those markets are ultimately reflected in the market prices of finished goods that are purchased by retail consumers, but costs may not be passed through on a dollar-per-dollar basis.

Retail electricity markets should be structured the same way. Purchases from spot electricity markets should be voluntary and by entities with the requisite skills. This does not preclude the price-responsiveness of small retail customers from being used to discipline price volatility, but that will normally be done by aggregation of small residential and commercial loads (with major appliances under real-time controls), and it will be the aggregator that monitors and reacts to real-time prices, not the customers. End-use customers may continue to be billed under an average fixed rate or other commercial arrangements at their discretion. Nonetheless, one or more of their major end-use loads may be bid into short-term markets, and the aggregator compensated at whatever price is negotiated in the market (*e.g.,* in an RTO's ancillary services market).

Markets for Customer Load Response (CLR)

Many large industrial consumers with curtailable loads, including many ELCON members, will want to enter the market directly and not via aggregators or other market intermediaries. But it should remain their choice. These customers will typically bid load that is otherwise served under firm long-term contracts or on-site generation, or a combination of the two. The customer may also aggregate curtailable loads from more than one facility in a region, depending on the source of generation that is being resold. ELCON calls the market for curtailable load, "Customer Load Response" (CLR) service.[9] Generally, CLR would be bid into regional markets for ancillary services or similar short-term or spot markets. Most industrials will attempt to bid when prices are highest (*e.g.,* day-of or hour-ahead markets) and not in day-ahead markets when the next day's market conditions have to be forecasted.

Many manufacturers have little or no price-responsive load and will not want to enter this market. Their loads will generally be served under long-term firm contracts or on-site generation with special provisions for standby or backup supplies to eliminate the risk of any interruption. It makes no sense to force such customers into the spot market.

RECOMMENDATIONS:

- Markets for Price-responsive Customer Loads – Markets—not *programs*—for CLR services should be established under the auspices of each FERC-jurisdictional ISO or RTO. This service should be structured as a new Order 2000 Function 9 requirement for RTOs to ensure that markets for CLR services are efficiently integrated with the other RTO real-time markets. As an RTO function, such markets would also be reasonably standardized within each Interconnection.

[9] CLR is a term adopted by ELCON to more accurately describe a service in which end-use customers may bid their loads into short-term markets, and to distinguish such service from demand-side management (DSM) programs to which it bears little resemblance. In some states, CLR-type services are called "load shedding," "negawatts," "demand response," "load management," or "demand relief" programs.

- Voluntary Entry to Wholesale Spot Markets – Markets for CLR should be voluntary. No customer or customer class should be forced to participate in this market.

- Exemption from Price Caps – The bids of CLR should be exempt from restrictions imposed by any price cap because CLR is a market *substitute* for price caps as a mechanism for restraining price volatility. To the extent CLR bids are subject to artificial price or bid caps, policymakers and regulators should be aware that this will discourage loads from making the investments necessary to participate in CLR markets and delay the emergence of truly competitive markets.

- All Customers Eligible to Enter Market for Price-responsive Loads – The opportunity to participate in markets for CLR should not discriminate on the basis of size or the customer's load. All customers and customer classes should be eligible on the same terms and conditions, and compensated at market prices.

- Consistency with Existing Contracts – CLR services would not abrogate contracts of existing interruptible customers. Customers with such contracts should be able to participate in CLR markets to the extent that such participation is not precluded under the terms and conditions in the contracts. This is a transition issue. As working competitive markets emerge and contracts expire, customers will seek new commercial relationships and weigh the benefits of contract terms consistent with any opportunities to participate in CLR markets.

- Direct Access and Customer Choice – All states should expeditiously establish competitive retail markets that allow end-use customers to choose their suppliers, and to freely negotiate the price, and terms and conditions of service.

3. COGENERATION & OTHER QUALIFYING FACILITIES

Since enactment of PURPA in 1978, cogeneration and small power producers have become an important part of the electric industry' resource base. Cogeneration, one type of combined heat and power (CHP) technology, is extremely attractive from a public policy perspective because of its extraordinary high operating efficiencies. The combination assures both an economically efficient and environmentally benign source of electricity and steam, and a major manufacturing facility with its employment and tax base, and other "multiplier" effects on the local and regional economy. Cogeneration units are also easier to site because they abut new or existing industrial facilities and thus lessen the local opposition typically directed at "greenfield" sites.

During the California Crisis, which is ultimately a crisis of supply, a series of inopportune actions severely restricted the amount of QF capacity available to the market, which only worsened the crisis. For example, many QF owners were not paid for power that they injected into the grid, jeopardizing the financial viability of the smaller generators and their steam hosts. Many QFs were idled because the owners lacked the credit necessary to purchase natural gas. The state also proposed legislative and regulatory measures that would require the owners of these facilities to accept compensation at less than the owners' actual out-of-pocket costs. The CAISO also proposed a series of actions that would require cogenerators to deliver power regardless of the physical limitations of the steam host. This risked damaging the generator or manufacturing process, and/or violating local permitting requirements.

RECOMMENDATIONS:

- Emergency calls on cogenerators should be separately negotiated with each generator and its steam hosts, in the interconnection agreement, to prevent any financial, physical, or environmental harm. Any power delivered to the grid should be compensated at its full market (or contractual) value. Cogenerators should not be required to sell power to any entity lacking the credit to honor the transaction.

4. FORWARD CONTRACTS

California established a four-year transitional market structure that required its three major investor-owned utilities to bid all their generation into a wholesale power exchange (the "spot" market) and to purchase all power requirements needed to meet their continuing native load obligations from the same spot market.[10] The utilities were, in essence, prohibited from using long-term forward contracts to hedge against spot market price risk. California also allowed it utilities to divest generation without requiring the new owners of that generation to sign vesting contracts with the old owners for the duration of the transition period (see "Generation Divestiture and Vesting Contracts" on page __). This would guarantee some pricing stability to remaining captive retail customers as markets were given a chance to organize and become workably competitive.

In all existing competitive commodity markets, buyers procure most, and in some cases, all their requirements under bilateral contracts, with each buyer or seller managing a portfolio of resources. Competitive electricity markets should be no different. Workably competitive markets must be decentralized to encourage producers and buyers to fairly negotiate prices and terms and conditions, at arms' length. As electricity markets are opened to competition, it is essential that the market design encourage forward contracting for most requirements. The establishment of a mandatory (as in California) or quasi-mandatory (as in Alberta, PJM, and New York) power exchange can create market conditions that allow generators to easily exercise market power that is not likely to be adequately mitigated by regulatory or antitrust agencies. For example, enactment of the Sherman and Clayton Acts—the main federal statutes dealing with antitrust—did not anticipate the *deregulation* of an industry and therefore are generally weak and ill-suited for addressing the market power abuses of transitions from a regulated market to an unregulated market. Producers can often exert undue political influence making regulatory remediation equally ineffective. The perceived benefits of mandatory or quasi-mandatory exchanges do not outweigh this risk of market power.

While a root cause of the California crisis was the prohibition on bilateral contracts, any new long-term contract, while the supply situation remained tight, was not likely to be cheap. In California, a combination of price caps, threatened government takeover, and the uncertainty associated with payments for power sold to a state agency with no prior experience procuring large quantities of power, introduced large risk premiums into the market. The lesson for other states is to never get into that bind in the first place. And the solution is simple. Set up a market design the encourages the use of forward, bilateral contracts, and avoid the temptation to require the establishment of a centralized power exchange with its false promise of "price transparency." Bilateral markets and

[10] Each utility was allowed to procure ancillary services in separate markets operated by the California Independent System Operator or CAISO. It was intended that the utilities would procure no more than about 5% of their needs in the ISO markets. Instead, the utilities gamed the two markets and began "leaning" on the ISO's ancillary services market for 20 to 30% of their needs in order to inflate their recovery of stranded costs. See "California Summer 2000 Power Crisis – A Report for ELCON Members," September 2000, at http://www.elcon.org/.

bidding behavior in short-term markets provide adequate price transparency for markets to efficiently clear without the added risk posed by a centralized exchange.

Other states hedged price uncertainty during the transition by requiring owners of divested generation to sell power back to the original owners at cost-based rates under so-called vesting contracts. This was a critical missed opportunity that California could not reverse.

RECOMMENDATIONS:

- States can reduce the uncertainty in the marketplace—and thus reduce the costs of long-term contracts—by demonstrating that new generation and transmission can be sited and built. This gives the market confidence that new resources will be brought on line in a timely manner, and commitments, during the transition and after, will be honored.

- States should encourage a market design that encourages the use of forward contracts to reduce dependence on more risky day-ahead or day-of purchases.

- States should not encourage or mandate the establishment of any centralized power exchange. But states should not discourage independent, private exchanges from operating in local markets.

- The terms of any vesting contracts resulting from generation divestiture should be limited to a reasonable transition period. Any such contracts should be retired in proportion to the amount of retail load that subscribes to alternative retail providers.

- States should not restrict the willingness of incumbent utilities to divest generation and other potentially competitive business functions. Combining regulated and unregulated business functions within the same corporate entity perpetuates market power. This is not in the best long-term interests of customers, a competitive electricity market, or the economy in general.

5. MARKET SURVEILLANCE

Competitive markets do not exist without rules and oversight by a higher authority. Any transition from a regulated to a deregulated market arguably requires even greater attention to fair play and transparency of market operation under all remaining laws and regulations.[11] The conduct of competition in the U.S. economy is not based on strict laissez-faire principles. All competitive businesses are subject to antitrust and public disclosure laws, including comprehensive market surveillance requirements, intended to protect both investors and consumers from undue predatory behavior.

For example, markets and exchanges for securities and commodities are subject to extensive oversight at all trading levels.[12] In addition, Congress and the states have enacted countless consumer protection laws that target specific abuses. A restructured electric industry—combining both regulated and unregulated market segments—should not be immune from comparable requirements for protecting investors and consumers.

In Order 2000, FERC requires RTOs to perform a "market monitoring" function. Specifically, as Function 6, RTOs are required to: (1) monitor markets for transmission service and the behavior of transmission owners and propose appropriate remedial actions if necessary; (2) monitor ancillary services and bulk-power markets that the RTO operates; (3) periodically assess how behavior in markets operated by others affects RTO operations and RTO operations affect those markets; and (4) provide reports on market power abuses and market design flaws to the Commission and other affected regulatory authorities, including specific recommendations. All FERC-approved ISOs have established a Market Monitoring Unit (or MMU), and all proposed RTOs have committed to the establishment of such an entity.

In addition in the FERC RTO rule, several states have established similar market surveillance functions, typically as separate entities within their regulatory agencies, to study the development of competition in formerly regulated retail markets, and to identify impediments to the full emergence of competition in those markets.

Electricity markets are inherently complex because the physical laws governing the operation of the interconnected grid are not intuitive to most people. This lack of transparency in market operation is especially susceptible to market design flaws, gaming behavior (see page __), and market power abuse.

Three forms of market power abuse are recognized in electricity markets and are subject to federal or state market monitoring functions: (1) vertical power, (2) horizontal power, and (3) localized power. An example of vertical market power would be any market

[11] The need for ongoing market monitoring is minimized if the potential to exercise market power is eliminated in the first place. See ELCON's *Profiles in Electricity Issues: Eliminating Market Power in the Transition to Competition.*

[12] The National Association of Securities Dealers' market surveillance and regulation division, NASD Regulation, oversees trading in approximately 5,000 securities by over 600,000 registered traders.

structure, rule, or procedure that allows a transmission owner to give preferential treatment to its unregulated generating or marketing affiliates for access to the transmission system. Horizontal market power would, for example, allow an owner of generation (or group of owners or "cartel") to unduly increase the price of ancillary services or power exchange clearing prices. Localized market power may be exercised by an owner of generation if one or more transmission constraints limit access to the "localized market" by competing generators. A "load pocket" is a prime example of this form of market power.

RECOMMENDATIONS:

The Market Surveillance Function

- Any market operated by a RTO, or on behalf of a RTO, should be subject to an independent market surveillance function to monitor such markets for potential design flaws, gaming behavior, and the exercise of vertical, horizontal, or localized market power. This includes markets for transmission services, ancillary services, and power exchanges. This function should not, and need not, extend to the monitoring of power exchanges (and other web-based trading platforms) that are independent of RTOs or bilateral transactions in which the RTO is not a party.

- States are encouraged to establish independent market surveillance functions to ensure that competition in their retail markets is not inhibited by the market design, gaming behavior, or the market power of incumbent utilities and their affiliates.

- The level of market surveillance in wholesale or retail electric markets—where regulated and unregulated entities (and affiliates) are co-mingled in the same market—should be at least as stringent as comparable market surveillance activities in any existing competitive market (*e.g.,* securities) unless the need for less surveillance is otherwise demonstrated.

- When a RTO has implemented any NERC reliability standard or business practice, the "market interface" between such standard or business practice, and the efficient operation of the wholesale bulk-power markets, should be subjected to the same market surveillance standards as other RTO market rules and procedures.

- For RTOs structured as for-profit transmission companies (transcos), all activities or business decisions associated with making tradeoffs between generation and transmission resources (*e.g.,* for the relief of transmission congestion, or generation interconnection policies and procedures), and any transaction involving an affiliate of a passive owner, should be subject to the market surveillance function.

- Uniform standards for market performance should be established and used for the monitoring of markets operated by RTOs or operated in association with RTOs, and for monitoring the "market interface" between NERC reliability standards and business practices, and the wholesale bulk-power markets.

Market Monitoring Units (MMUs)

- Market monitoring units (MMUs) should be independent of market participants, RTOs, and regulatory commissions. MMUs should recommend to the appropriate regulatory commissions improvements or corrections to market rules and procedures, tariffs, or market design. MMUs may also advise antitrust agencies of any potential antitrust violations revealed by its surveillance activities.

- Each MMU should have adequate resources, professional staff, and the ability to retain outside experts, as it deems necessary, to accomplish its mission. While RTOs are responsible for recovering the costs of market surveillance activities, an MMU's budget should be subject solely to FERC's oversight, and not subject to modification or veto by the RTO.

- MMUs should not be allowed to exercise *de facto* regulatory authorities, *e.g.,* to impose penalties on market participants for improper behavior, to set price or bid caps, or to unilaterally adjust market clearing prices or bids.

- FERC is urged to establish separate MMUs for the Eastern and Western Interconnections with the sole function of ensuring resolution of Function 8 (Interregional Coordination) issues between adjacent RTOs, as they may exist, within each interconnection.

- The professional staff of MMUs should not use their position to advocate a particular market design structure or philosophy for which viable alternative market design structures or philosophies exist.

6. SHORT-TERM RELIABILITY

Reliability (of electric service) is a much-abused word, meaning different things to different people. Most retail customers associate the word with the availability of power at their low-voltage (distribution) level of consumption. Outages at distribution voltages are relatively common compared with failures at transmission-level voltages because the distribution system is more sensitive to weather extremes, load growth, and utility maintenance practices. But transmission-level outages typically impact a wider geographical area and impose more visible and greater economic costs and risks to public welfare and safety. The legendary Northeast Blackout of 1965 resulted in the creation of the North American Electric Reliability Council (NERC). The 25-hour blackout in New York City in 1977 resulted in widespread rioting, looting, and economic costs estimated in the hundreds of millions of dollars. A series of blackouts in the Western Interconnection in 1998 instigated a major investigation directed by the Secretary of the U.S. Department of Energy. The more recent episodes of controlled "rolling blackouts" in California have been generalized as an "energy crisis" on par with the energy crisis of the 1970s.

SELECTED POWER OUTAGE COSTS

(SOURCE: U.S. DOE & EPRI)

INDUSTRY	AVERAGE COST OF DOWNTIME PER HOUR
CELLULAR COMMUNICATIONS	$41,000
TELEPHONE TICKET SALES	$72,000
AIRLINE RESERVATIONS	$90,000
CREDIT CARD OPERATIONS	$2,580,000
BROKERAGE OPERATIONS	$6,480,000
MICROCHIP MANUFACTURING	$60,000,000

NERC Definition of Reliability

NERC defines reliability in terms of two inter-related risks. The first risk is the short-term "security" of the bulk power grid. This means the resilience of the high voltage transmission system to failure if certain inviolate laws of physics are breached. Security addresses the manner in which the interconnected grid is operated, and any failure to operate the grid as prescribed by NERC, puts the grid at risk of an outage. The term "interconnected" connotes the fact that the grid—a single electric circuit—is owned and

operated by many utilities, each attempting to operate its own piece of that circuit independent of other utilities.[13] NERC has established a series of nine Operating Policies to maintain security.

The second risk in NERC's definition of reliability is "adequacy." This refers to the availability of generating resources and transmission capacity to meet expected contingencies such as the unexpected outage of a major generating unit or transmission line. NERC has established a series of Planning Standards that are intended to ensure adequacy. But ensuring "adequacy" does not always guarantee security. The security of the interconnected grid can be at risk because of the failure to operate the system as required by NERC Operating Policies.

Since the early 1970s, NERC has been an ad hoc, voluntary association owned by nine or ten Regional Reliability Councils or RRCs.[14] The RRCs fund the activities of NERC. The members of each regional council were typically the utilities that owned the transmission facilities within each region. This included both investor-owned and public utilities. As a strictly voluntary group, without any express federal or state statutory authorization, NERC was and is incapable of enforcing its Operating Policies or Planning Standards. As a result, the actual operating and planning practices of the regional councils and any of its members are not always consistent with NERC standards, or with each other. In the past, when most utilities met the needs of its native-load customers with its own resources, this was not much of a problem except for the many small transmission-dependent public utilities (municipal utilities and rural cooperatives) which had to rely on the willing cooperation of larger transmission-owning utilities to provide wheeling and grid support services to enable the smaller utilities to reliably and economically meet the requirements of their customers. Nonetheless, the volume of such "wholesale" transactions between and among utilities was relatively small compared with the power each utility generated and delivered to its own customers. NERC standards primarily addressed transactions between utilities (or more correctly, between utility "control areas").

Changes in Transmission System Usage

Beginning immediately after enactment of the Energy Policy Act of 1992, the number of wholesale transactions began to grow, especially by third-party users of the transmission system. The 1992 federal law created two new wholesale entities, exempt wholesale generators (EWGs), a new class of independent "merchant" generators, and power marketers. Power marketers are market intermediaries whose core business is to arbitrage interregional cost disparities (and price risks). Power marketers may or may not also own physical generating assets. Their "trading" behavior is quite different from

[13] NERC standards generally apply to three separate North American electrical circuits called "Interconnections." These three Interconnections encompass most of Canada, all of the lower 48 states, and parts of Mexico. They are the "Western Interconnection" (west of the Rocky Mountains); the "Eastern Interconnection" (east of the Rockies); and the Electric Reliability Council of Texas (ERCOT) that consists of most, but not all, of the state of Texas.

[14] There were originally nine regional councils. A tenth—the Florida Reliability Coordinating Council (FRCC)—was spun off from the Southeast Electric Reliability Council (SERC) in 1996.

the relatively passive management style of regulated utilities whose core business has traditionally been focused on regulated or political markets, not economic markets.

Many utilities were also becoming increasingly dependent on off-system power purchases because of a *de facto* moratorium on new generation construction. Burned by embarrassing cost overruns associated with investments in nuclear plants, and subjected to regulatory and political pressures to adopt conservation and other social programs as an alternative business model, many utilities abrogated their "public service" or "public interest" responsibilities, and ceased to adequately plan for and make the long-term investments necessary to fulfill those responsibilities. Many utilities established their own power marketing operations to manage increased off-system purchases.

The changes in transmission system usage created a dilemma for NERC: the organization's Operating Policies and Planning Standards were rapidly become obsolete. NERC was also under pressure from new market participants to broaden representation in the organization's governance process to include non-utility stakeholders. The regional councils were also split on whether and how to change the organization and generally resisted sharing control with other stakeholders. This split reflects the lack of consensus among utilities on the direction of industry-wide restructuring, and has seriously hamstrung NERC's effectiveness. In 1998, NERC proposed federal legislation to re-establish itself as a "self-regulated" organization subject to FERC oversight. The legislation intended to break the hiatus and mandate the establishment of a new organization more compatible with the needs of a new industry structure and new industry participants.

The Market Interface

Without waiting for federal legislation, NERC made an important concession to the changes in electricity markets by creating a new standing committee, the Market Interface Committee (MIC). The MIC's mission is to review the impacts of NERC reliability standards on the commercial electricity markets—the so-called "market interface." Since its inception, the committee has focused its attention on allegations that some transmission providers have been misusing certain reliability standards and practices for commercial advantages. For example, NERC's Transmission Loading Relief (TLR) procedure was intended as an emergency curtailment process that was only used as a "last resort." Instead, the procedure is increasingly invoked as a congestion management tool because transmission paths are regularly oversold. See page ___. This type of practice jeopardizes the reliability of the bulk-power grid and disrupts the wholesale markets. Absent federal legislation, NERC is incapable of preventing such practices.

New Reliability Model

In 1999, NERC's Operating Committee created the Control Area Criteria Task Force (CACTF) in response to two industry dynamics. First, some power marketers and independent power producers were forming generator-only control areas because of a perception that affiliated generators and marketers had a commercial advantage—by

virtue of corporate affiliation with a "control area operator"—over entities with no such affiliation. Second, new industry structures were being formed (*e.g.,* ISOs) with important grid operating responsibilities that were never anticipated in NERC Operating Policies. The CACTF's charge was to establish, over the short term, some consistency and fairness with respect to the certification and treatment of control area operation, and more important for the longer term, redefine the essential functions and responsibilities for grid reliability that are independent of existing or any new corporate structures that emerge as the industry evolves and accepts a more competitive market model. It was understood that, in the new industry, control area functions and responsibilities would be unbundled and repackaged in new corporate entities and that NERC reliability standards should be written to accommodate any such changes without the revision of any standard.

In February 2001, the task force approved two final reports.[15] The first report, *Basic Operating Functions and Responsibilities,* defined a new "Reliability Model" that consisted of certain "root-level" functions that ensure reliability and meet the needs of the marketplace. The new model and functions would accommodate any new industry structure resulting from the unbundling of traditional utility responsibilities. The new functions are:

Service Functions:

- Security Authority
- Interchange Authority
- Balancing Authority
- Transmission Service Providers
- Distribution Providers
- Compliance Monitor

Merchant Operating Functions:

- Generator
- Load Serving Entities
- Purchasing-Selling Entities

Non-Merchant Operating Functions:

- Transmission Owner
- Transmission Operator

In a second report, *Independence Considerations for Organizations Performing Reliability Functions*, the task force concluded that the "merchant" Operating Functions in its Reliability Model had to be independent of certain Service Functions because these

[15] North American Electric Reliability Council, *Basic Operating Functions and Responsibilities*, Final Report of the Control Area Criteria Task Force, February 28, 2001, and *Independence Considerations for Organizations Performing Reliability Functions*, Report from the Control Area Criteria Task Force to the NERC Board of Trustees, February 2, 2001.

functions are "an important part of ensuring a reliable power supply as well as providing market solutions to reliability problems." These functions are the Balancing Authority, Security Authority, and Transmission Service Provider.

The task force concluded that two "guiding principles" establish the relationship between the marketplace and reliability:

1. Reliability and commerce are inseparable and mutually dependent, and

2. A viable electricity market is essential for a reliable bulk power system, and vice versa.

While perhaps not intended as such, the Reliability Model developed by NERC's CACTF may be an extremely powerful tool for regulators and antitrust agencies. The model provides a very convenient template for scrutinizing corporate structures (*e.g.,* RTO or Transco proposals) for potential self-dealing opportunities.

RECOMMENDATIONS:

- Federal Legislation – Congress is urged to enact legislation requiring the establishment of a new North American electric reliability organization subject to FERC oversight. The new organization should have the authority to enforce compliance with its standards.

- "Plan B" – Pending the enactment of federal legislation, NERC should initiate internal reforms of its governance structure that balance the interests of all industry stakeholder groups and eliminate the ability of RRCs or transmission owners, as a group, to veto any NERC action.

- New Reliability Model – FERC, state regulatory agencies, and the federal antitrust agencies are urged to review the new NERC Reliability Model and consider applying this model as a new tool to fulfill their statutory responsibilities associated with market power abuses.

DEALING WITH MARKET FAILURE

1. MARKET "CIRCUIT BREAKERS"

Price Caps

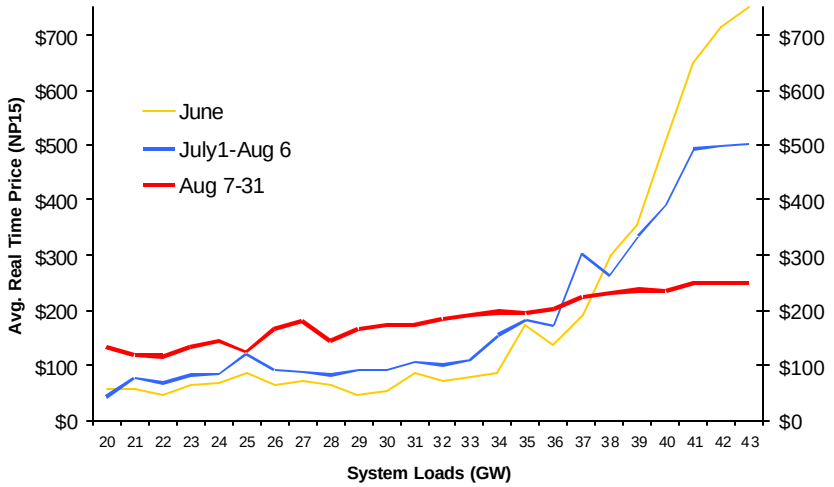
As a general principle, price caps are inconsistent with the basic operation and incentive structure of competitive markets. Where markets are clearly dysfunctional, certain forms of price caps may be necessary to protect consumers and other market participants until the market is reorganized and stabilized. However, once established, price caps are also hard to eliminate. Opposition to price caps often arises over the fear that once price caps are imposed the will become a permanent feature of the market.

One form of price cap that has been used in ISO markets is the bid cap. This sets a limit on the price that a supplier may offer to sell its power.

Price cap proposals generally expand two extremes. At one extreme, the cap would be set as low as possible and approximate cost-based rates. Price caps that are politically motivated tend to be this kind. The other extreme would set the cap rather high and attempt to approximate (and perhaps exceed) long-run replacement costs. This second form of cap is often called a market "circuit breaker" or "damage control" cap.

CAISO Real Time Prices (NP15)

(June-August, 2000, Dollars per MWh; Source : California ISO)



Price caps are controversial because there is substantial evidence suggesting that they are counter-productive, especially caps that target the low end of the producer-cost spectrum. In California, during the summer of 2000, total costs increased as bid caps were ratcheted down from $750 to, $500, and finally, to $250. Certainly, if caps are set low for long periods of time, they will discourage new investments. And price caps at

any level will discourage the entry of price-responsive, curtailable loads into the market and deny the market its rightful "demand curve."

RECOMMENDATIONS:

- As a general principle, price caps (or bid caps) should be avoided because they can severely discourage market entry by price-responsive, curtailable loads and new generation.

- Price caps should not be imposed solely to suppress price volatility. Price volatility is a natural attribute of healthy competitive markets.

- In clearly dysfunctional markets, circuit-breaker type caps may be necessary to prevent a total market collapse. Such caps must be eliminated as soon as the market is functioning properly.

- The bids of price-responsive loads should be exempt from any price or bid caps. Price-responsive load is a *substitute* for any price or bid cap, and any attempt to limit the remuneration to customers reselling their load will distort the market and negate the benefit of a demand response in the market.

2. BANKRUPTCY

Reorganization and protection from creditors under Chapter 11 of the U.S. Bankruptcy Code is not uncommon. Yet, the bankruptcy of electric utilities is somewhat rare. But it has occurred in recent years. Before recent events in California, the episodes involving Public Service Company of New Hampshire, the Western Public Power Supply System (WPPSS and infamously remembered as "WHOOPS"), and El Paso Electric Company were the most well known examples. In each instance the "lights stayed on." Unlike bankruptcies in other industries, where the firm may be in dire straits because the market for its products or services is no longer there, this is not the case with electric utilities. Often the problem was the political unacceptability of the rates charged to customers that the utility deemed necessary to keep it financially solvent.

Part of the dilemma is the traditional cost-plus mentality of utility management. It was and is their expectation that any cost they incur must be recovered from customers. The rate-setting process was never immune from political influences that, most of the time, worked to the advantage of the utilities. Hence, the enormous "stranded cost" bill that is a pre-condition to any movement to a more competitive environment. In a more competitive industry, cost accountability is shifted to the company and its shareholders, and not simply passed on to captive "ratepayers."

But there are limits. The California Crisis was, in part, triggered by a generous accommodation of the huge stranded costs of the state's large investor-own utilities: PG&E, SCE, and SDG&E. A transitional market structure, which was largely a by-product of the utilities' own lobbying efforts, proved untenable in the face of stresses that should have been anticipated, or planned for as plausible contingencies.

The crisis has nurtured a public debate on the appropriate role, if any, of bankruptcy protection under federal law when efforts to restructure the electric industry seemingly go awry. Bankruptcy is an unpleasant situation and for any industry charged with the "public interest," it is a potentially huge embarrassment to state regulators and other officials who are accountable, directly or indirectly, to voters.

RECOMMENDATIONS:

- Bankruptcy protection from a utility's creditors should always be an option if the alternative is to simply recover all the costs—prudent or otherwise—from ratepayers.

- Regulators should provide sufficient oversight of utility operations, such as establishing clear rules for the inter-affiliate transactions of holding companies, to preserve the financial integrity of their jurisdictional utilities and thus reduce the probability of new utility bankruptcies.

3. EMERGENCY AUTHORITIES

In 2001, both California and New York took emergency actions to expedite the siting of new generation in anticipation of severe capacity shortages during the imminent peaking season. In 1998, Wisconsin took similar measures. Other states may find themselves in a comparable situation if supply resources available to meet the needs of in-state loads become inadequate, or if transmission congestion is not adequately addressed and eliminated. The exact circumstances in California, New York, or Wisconsin need not be replicated to create either of these risks.

Power outages can have catastrophic consequences. Rioting and loss of life have occurred in past power outages, in addition to severe economic damages. In California, the siting of emergency generation was severely hampered by local opposition and the unwillingness to be flexible—even in a crisis—with other public policy objectives. Nonetheless, California initiated a proceeding to identify constraints in their siting and permitting procedures with the intent of finding ways to streamline the processes.

RECOMMENDATIONS:

- States should identify and encourage any measures that streamline or expedite the siting and permitting processes to enable new resources to efficiently get on line, and not have to resort to emergency procedures.

- States should prepare emergency siting guidelines *before* such guidelines are needed, and avoid the need to prepare such guidelines in a crisis atmosphere.

- State legislatures should consider enacting limited waivers of air and water quality standards (including land-use restrictions for temporary mobile generators) during emergency situations that risk major power outages. This should include the preemption of any local restrictions. Once an emergency has been resolved, any waivers should be rescinded and power plants that operated under such waivers should be required to comply with all air and water quality standards and land-use restrictions that were required absent the emergency.

ENSURING COMPETITIVE MARKETS

1. MARKET STRUCTURE:
Forward Contracts in Bilateral Markets

Energy Market Structure

In competitive markets for electricity products and services, such products and services should be traded in forward markets through freely negotiated bilateral or multilateral contracts. The market structure should be *decentralized* and allow the formation of regional trading hubs. Independent power exchanges (Web-based trading sites) should be allowed to enter these markets. These exchanges would enable market participants to refine their contract positions as market conditions change as a result of weather, fuel prices, or economic factors. The exchanges also provide near real-time price transparency by posting energy prices at each trading hub.

Prices in the balancing energy market should be developed within the hour (or less) on a nodal or zonal basis. Prices, in either case, would be known *ex post*.

The benefits of this energy market structure include:

- "Look and Feel" of Other Competitive Markets – Decentralized markets is the norm in capitalist societies. There are few examples of centralized exchanges, and fewer optimized "dispatch" markets, in which the entire physical volume of a commodity market is allocated and priced.

- Product Differentiation – Forward markets allow a variety of contracts, and contract terms and conditions, tailored to the specific needs of individual *customers*. In a market dependent on forward contracting, there is no presumption that all customers want the same physical or financial products, and thus, *the market orientation becomes customer focused and customer driven.* Customers are free to negotiate prices, terms and conditions, risk management, and other services that meet their personal or commercial needs. Suppliers are free to offer innovative and different products and services to individual customers or aggregated customers.

- Efficient Trading Continuum – Bilateral trading is a continuous, dynamic process, unrestrained by the inflexible and programmatic procedural rules of centralized exchanges or centrally-dispatched pools that limit trades to preset templates (*e.g.,* day-ahead and day-of or spot transactions). This allows new (and increasingly accurate) information to be rapidly reflected in prices and the risk management strategies of customers. Real-time forward markets and price information enable end-use customer participation in the balancing energy markets and congestion management. This will greatly enhance short-term reliability and reduce extreme price volatility inherent in supply-side only markets.

- Innovation – This market structure—again compared with market designs based on centralized exchanges or centrally dispatched pools—allows free entry of competing market mechanisms (*i.e.,* a "market of markets"), a more customer-driven approach

to selling the product (and its complements), and thus, greater opportunities for new technological and market innovations. The emergence of independent web-based B2B platforms for anonymous bid/ask transactions is an example of the potential for innovation in a decentralized market structure.

- Market Power Mitigation – Markets based exclusively on centralized exchanges or centrally dispatched pools, or where an exchange is mandated as part of a hybrid structure (*e.g.,* the Cal PX), are highly susceptible to the horizontal market power of generators. In the United States, policy makers, regulators, and antitrust agencies are not likely to require the degree of corporate separation necessary to adequately mitigate horizontal market power. However, the use of multiple settlements for energy transactions can reduce the amount of gaming and exercise of market power.

Market structures based on centralized exchanges or centrally dispatched pools are carryovers from the "tight" pool and vertically integrated utility structures of the regulated industry where product differentiation, trading flexibility, innovation, and customer responsiveness were generally non-existent.

Transmission Rights & Congestion Management

The regulated market for transmission services and RTO responsibilities for congestion management should rely on flow-based, *physical* transmission rights determined in an initial auction. [16] The contract-path model for transmission services embedded in FERC rules and regulations should be abandoned.[17]

PTRs should be limited to *flowgates* as determined by an RTO or NERC. Flowgates are defined as transmission interfaces that experience commercially significant congestion, and therefore, require financial settlement. The transfer capability of a flowgate is based on the simultaneously feasible thermal/stability limits of other flowgates involved in any transaction as allocated by *power transfer distribution factors (PTDFs)*. PTDFs are calculated by NERC's *Interchange Distribution Calculator (IDC)* and are used by NERC-certified Security Coordinators to invoke Transmission Loading Relief (TLR) Procedures. PTDFs are calculated based on all system impedances and the addition of a new flowgate will not change the PTDFs across existing flowgates. The removal of flowgate status on an interface should typically follow the addition of new generation or transmission capacity and the market for physical transmission rights on the interface should have adequate time to adjust.

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[16] Two technical papers advocating the "physical" rights model are: Hung-po Chao, Stephen C. Peck, Shmuel S. Oren, and Robert B. Wilson, "Flow-Based Transmission Rights and Congestion Management," *The Electricity Journal,* Volume 13, No. 8, October 2000, pages 38-58; and Shmuel S. Oren and Andrew M. Ross, "Economic Congestion Relief Across Multiple Regions Requires Tradable Physical Flow-gate Rights," University of California Energy Institute, PWP-076, May 2000. A website devoted to a spirited debate between the decentralized, physical rights based markets and centralized, financial rights markets is at http://www.ksg.harvard.edu/~hepg/flowgate.htm .

[17] The contract-path method ignores the consequences of loop flows or parallel path flows (*i.e.,* Kirchoff's laws) in any transmission transaction.

The benefits of this transmission market structure include:

- Tradability of Transmission Rights in Secondary Markets – Physical transmission rights are fully tradable, and this enables transmission congestion to be "self-managed" in forward markets. Unlike *financial* transmission rights, which have limited liquidity in secondary markets, efficient secondary markets for physical transmission rights can be established.

- Lower Transaction Costs – Participation in forward markets, and one or more independent power exchanges, will be familiar to large customers with experience in competitive natural gas markets. With physical transmission rights, bilateral trades are achievable without a "middle-man."

- Market Power Mitigation – The establishment of secondary markets for transmission capacity are an important form of market power mitigation.

RECOMMENDATIONS:

- Energy Market Structure – The market structure should be decentralized and allow the formation of regional trading hubs. Most electricity products and services should be voluntarily traded in bilateral markets. The use of government-mandated centralized exchanges should be avoided.

- Locational Pricing to Clear Real-time Markets – Spot prices in the balancing market should be developed as close to real-time as practicable and on a nodal or zonal basis.

- Flow-based, Physical Transmission Rights – The regulated market for transmission services and RTO responsibilities for congestion management should rely on flow-based, physical transmission rights. The contract-path model for transmission services embedded in FERC rules and regulations should be abandoned.

- Secondary Markets for Physical Transmission Rights – Secondary markets for physical transmission rights should be established.

2. INTERCONNECTION RIGHTS:

Removing Entry Barriers to Industrial Cogeneration, Independent Merchant Power Plants, and Distributed Generation

The development of innovative and independently owned generation resources in a competitive electricity marketplace is one of the great promises of industry restructuring. These resources include industrial cogeneration and self-generation, merchant power plants, and distributed generation (DG).[18] Each of these technologies, which are financed in private capital markets, provides entrepreneurial and operating efficiencies and environmental benefits that have been absent from past *rate-based* utility investments. The proximity to customer load of some of these technologies (*e.g.,* DG and industrial cogeneration) also provides other benefits, including enhanced power quality, short-term reliability, and deferment of investments in new or upgraded transmission and distribution facilities. However, that does not diminish the value of relatively large merchant power plants provided that they are sited to efficiently mitigate transmission congestion.

But utilities have always fiercely opposed technological competition, *i.e.,* any attempt by retail customers or other entities to bypass the utility's "one-size-fits-all" service with a superior inside or outside the "fence" alternative. As a monopoly, a utility has no economic incentive to conduct interconnection studies and negotiate interconnection agreements with new independent generators (of any size) on a *best business practices* basis. Quite to the contrary, utilities routinely use their monopoly advantages to harass any potential competitor. Manipulating the process for obtaining and constructing physical interconnection with a utility's transmission or distribution network has always been one of the more reprehensible means of discriminating against independent generators.[19]

Industry restructuring does not end this problem. The continuation of utility holding companies in an era of supposed "competition" perpetuates the coexistence of regulated and unregulated affiliates within the same corporate entity. The business mindset of

[18] Distributed Generation (DG) is generally recognized as a subset of a class of capacity or energy resources called "Distributed Resources" or "DR." However, there is no general agreement on what qualifies as a "DR" or "DG." Some advocates would limit DR to small-scaled resources with a name-plate rating at or below some arbitrary threshold regardless of the economic and/or environmental benefits of larger units.

[19] Three higher court decisions were necessary to uphold PURPA against attacks by the electric utility industry. In FERC v. Mississippi, 454 U.S. 752 (1982), the Supreme Court ruled that PURPA is constitutional and that Section 210 does not intrude on state sovereignty in violation of the 10th Amendment. In American Paper Institute v. AEP, 461 U.S. 402 (1983), the Supreme Court upheld FERC's authority to require utilities to purchase power from QFs at avoided costs and upheld FERC's rules requiring utilities to make physical interconnections with QFs. Later, in Gulf States Utilities Co. v. FERC, 922 F. 2d 873 (D.C. Cir. 1991), cert. Den. 502 U.S. 819 (1991), the D.C. Circuit upheld FERC's determination of what constitutes a "facility" under PURPA for the purpose of consuming electricity from a qualifying cogenerator.

these entities also tends to replicate traditional utility (*i.e.,* monopoly) values and aspirations and not the free enterprise motivation of truly competitive industries. The utility holding company structure in a partially deregulated environment creates the economic incentive to use control of regulated services to give preferential treatment to the business transactions of unregulated affiliates. Thus, any potential competition to a utility's generation or power marketing affiliates can be impeded by all sorts of arbitrary "entry barriers" imposed by sister transmission or distribution affiliates. The Electric Power Supply Association (EPSA) aptly illustrates this problem:

> In short, entities that may be economically advantaged by delaying new interconnections, that may be inclined to favor transmission solutions over generation solutions, and that stand to gain from having transmission upgrades paid for by generators should not be charged with determining the nature and scope of a new generator's interconnection.[20]

EPSA also correctly alludes to a new entity in the restructured industry with similar prejudices. FERC Order 2000 allows the establishment of for-profit transmission companies that may qualify as RTOs. Whether such entities can be created that are truly independent of ostensibly *passive* utility owners is one issue; but an equal concern is the economic incentive "to favor transmission solutions over generation solution." Transmission and generation often compete to relieve transmission congestion. Given the fact that FERC continues to regulate transmission—and has offered the promise of financial incentives to increase transmission investment—the economic incentive to discourage new generation that might also relieve transmission congestion becomes compelling.

RECOMMENDATIONS:

Basic Right to Interconnect with the T&D Network

- Nondiscriminatory Interconnection Service – Access to interconnection service should not discriminate on the basis of ownership, technology, fuel, QF-status, or size. New small facilities should not be given superior rights compared with large facilities simply because they are small, and vice versa.

- Standby, Maintenance, and Supplemental Services – Interconnection with the T&D network of any utilities should not in any way impede the ability of a new generator to access fair and nondiscriminatory standby, maintenance, and supplemental services.

Industrial Cogeneration & Independent Merchant Power Plants

- RTO Administration of Interconnection Service – Any new generator that seeks interconnection to the bulk-power transmission system should have the right to request interconnection service pursuant to a FERC-approved nondiscriminatory

[20] Electric Power Supply Association, "EPSA Position Statement on Bill of Rights for New Generation Interconnection," June 2000. ELCON's recommendations on interconnection adopt many of the EPSA positions.

interconnection service administered by an RTO. Such services, including a *Model Interconnection Agreement*, should be specified and enforceable in RTO tariffs. The model agreement should establish a framework for negotiations, and if necessary, serve as a default agreement in the absence of a mutually negotiated bilateral agreement.

- Interconnection Studies – A new generator should have the right to an interconnection study performed by an independent (not-for-profit) RTO or other qualified independent contractor certified by the RTO. For interconnections to facilities operated by for-profit RTOs (*i.e.,* Transcos), the new generator should have the right to have any interconnection study performed by the RTO audited by an independent contractor, or alternatively, the right to have such studies performed by an independent contractor. A new generator should have the right to participate in the interconnection study process and to have the study and the interconnection completed in an expeditious manner. At the discretion of the new generator, the negotiation of the interconnection agreement may proceed in parallel with the inter-connection study.

- Interconnection Study Costs – A new generator has a responsibility to pay for the interconnection study as long as only the generator benefits from the new physical facilities created by the interconnection, including upgrades to the existing transmission system. To the extent such new physical facilities or transmission system upgrades benefit other market participants, the cost of the interconnection study should be allocated to the other market participants in proportion to the benefits received.

- Queuing Policy – FERC should promulgate a fair and nondiscriminatory policy or rule for guiding the processing of multiple applications for interconnections. A new generator should have the right to no inferior standing in a "queue" compared with any existing generator that is seeking to expand its generating capability at one or more sites.

- Interconnection Agreement – A new generator should have the right to execute a FERC-approved interconnection agreement that specifies exactly what is necessary for the project to safely and reliably interconnect with the bulk-power system.

- Interconnection Costs – A new generator should have the right to receive a binding commitment as to all interconnection costs and the right to own certain of the interconnection facilities. Interconnection costs that benefit other market participants, in addition to the new generator, should be allocated to the other market participants in proportion to benefits received (See below, "Transmission system enhancements").

- Interconnection Construction Schedule – A new generator should have a right to receive a binding commitment as to the construction schedule with rights to liquidated damages if the interconnection service provider fails to perform on schedule.

- Transmission Service Reservation – Any new generator should not be required to reserve transmission service as a pre-condition to the physical interconnection to the grid. Generation owners are not always the party responsible for ultimately identifying points of delivery.

- Transmission System Enhancements – If a new generator is required to financially support an upgrade to the transmission system or enhancement of the system beyond what is required under a minimum interconnection standard, the generator should have the right to receive transmission rights and/or congestion revenues in proportion to the amount of capacity created by the upgrade or enhancement.

Distributed Generation

- Nondiscriminatory Interconnection Service – Any new distributed generator that seeks interconnection to a utility's distribution system should have the right to request interconnection service pursuant to a state-approved nondiscriminatory interconnection service. This service should include a Standardized Interconnection Agreement.

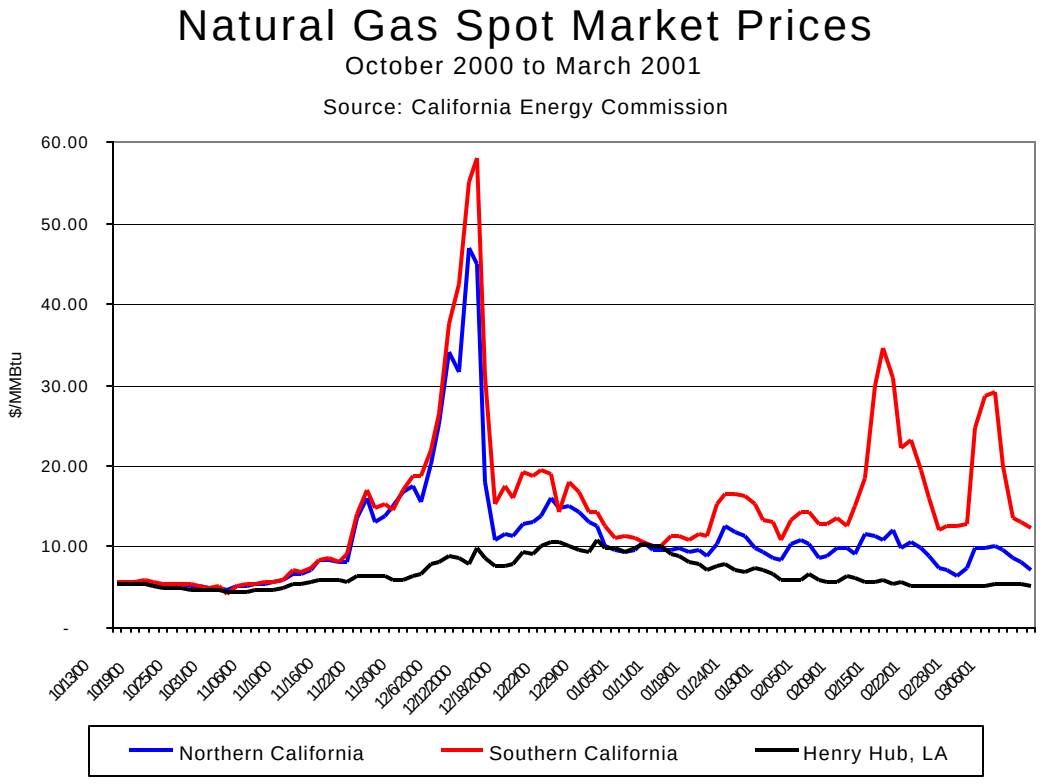
- National Interconnection Standards – The development of uniform standards for interconnecting distributed resources with electric power systems by the Institute of Electrical and Electronic Engineers (IEEE) eliminates important economic and technological barriers to market entry by small-scale distributed generators.

- Stranded T&D Costs – Utility transmission and distribution companies should not be financially immunized from any risk associated with customer loads, and therefore are not entitled to stranded cost recovery for any activity that is exclusively on the customer side of the meter. It is illogical—and self-serving—that utilities would claim exposure to such risks (in the same context as the "stranding" of generation assets) and at the same time seek financial incentives to construct new or upgraded facilities because of past under investment in the same T&D assets.

- Prohibition of Distribution Company Ownership of DG – Regulated distribution companies should not be allowed to own DG assets and include such assets in the utility's rate base. Otherwise, this would allow the local utility to return to the generation business. "Wires" companies need to establish a business culture, and business values, that are compatible with deregulated generation markets and competitive markets in general.

3. NATURAL GAS INFRASTRUCTURE

Most new generating capacity that is planned or under construction is expected to burn natural gas. For example, the Energy Information Administration estimates that 93% of planned capacity additions through 2004 will be gas fired. Natural gas enjoys this advantage because of an unusually sustained period of relatively low wellhead prices (the infamous "gas bubble") and aggressive marketing of the environmental benefits of natural gas compared to coal, hydro, or nuclear capacity. But low wellhead prices also discouraged domestic exploration for new reserves and development (new drilling) of



existing reserves, and hence, the emergence of a classic "boom/bust" cycle of prices.

The fact that recent price increases in domestic natural gas markets have coincided with electric capacity shortages in some regions has raised fears that a competitive electric industry may become too dependent on natural gas as a fuel. For example, in California, the state's power crisis coincided with extraordinary increases in wholesale natural gas prices. The price of natural gas crossing the border into California from Arizona was often double the national average.

Traditional Service to Core & Non-core Customers

Traditionally, interstate pipelines deliver baseload gas supplies, including storage injection. Some customers deliver gas in off-peak periods for storage and later for redelivery in peak periods. Transportation and storage allows gas-on-gas price competition in forward and spot markets for this commodity. Storage strategies were developed primarily to meet the peak needs of core markets such as residential and commercial space heating in the winter months. Increasingly, industrials have become direct firm or interruptible customers of pipelines, independently purchasing their own gas supplies. LDCs generally classify industrial process consumers and power generators as non-core customers, and treat them as interruptible loads in the event core customers need the capacity or commodity.

New Convergence Issues

The growth in demand for natural gas for generation projects as well as more traditional uses has produced a new set of "convergence" issues affecting both interstate pipelines and LDCs. In particular, the demand for capacity to serve new or additional gas-fired generation loads is creating even greater need for additional pipeline infrastructure. In the case of interstate pipelines, many generation projects seek to be directly connected to the interstate pipelines, competing for capacity with industrials and other shippers and requiring the addition of capacity. Further, generation projects may use gas in a different seasonal pattern than has been present on pipelines, placing additional capacity stresses on the infrastructure. For example, where many gas pipelines traditionally saw higher use of capacity in cold winter periods and less utilization of capacity in summer periods, generation projects that serve summer peaking needs will create a flatter and more consistent use of existing gas pipeline capacity year-round.

Likewise, LDCs' non-core customers are almost always connected to the same electric transmission system that serves the compressor stations of the pipelines. This poses no service risk as long as non-core consumption is a small fraction of core consumption. But for many LDCs, non-core consumption by industrial process consumers and power generators has become the dominant on-system LDC load. In addition, summer-peaking demand by power generators will compete with LDC use of transportation capacity to move gas to storage in the traditional off-peak periods of the gas market. This new load profile–in which demand for gas and pipeline capacity experiences peaks throughout the year–will stress the natural gas infrastructure throughout the country, and particularly in areas in which pipeline capacity already is inadequate. As a result, in order to ensure that all consumers seeking gas, whether for generation or for other uses, have access to the capacity to move gas to market, it is essential to construct new and upgraded interstate pipeline infrastructure.

RECOMMENDATIONS:

- Convergence – Electricity and natural gas markets are becoming increasingly intertwined (*i.e.,* convergent), and the planning and siting of additions to the natural gas infrastructure should reflect this change.

- Need for New Interstate Pipelines & Storage Facilities – The rapidly increasing demand for industrial processes and power generation, requires new interstate

pipeline capacity and storage facilities to meet these needs and ensure adequate capacity to support the storage requirements of traditional core customers. This infrastructure growth is vital to ensure that all consumers can secure desired natural gas service. Market commitments for new pipeline expansions should accommodate increasing demand by all customers including industrials, generators, and the core and non-core customers of LDCs.

- State Responsibilities – Intrastate pipelines and local distribution company facilities should be designed, sited, and built to meet the market-driven needs of power generators, by recognizing the unique characteristics of the electricity markets and the changing seasonal of the natural gas markets. This may require the rationalization, or redefinition, of core and non-core customers with the realities of mutually competitive electricity and gas markets.

- Approval Process – The regulatory approval process for new storage facilities and pipelines should be streamlined, and approvals should be forthcoming on a more timely basis.

- Fuel/Storage Competition – The need for new storage and pipeline capacity should include an assessment of such alternatives as peak-shaving supplies from compressed natural gas or LNG.

4. NEW GENERATION, FUEL SUPPLY & FUEL DIVERSITY

Generation "Planning" Under Regulation

A major motive for industry-wide restructuring was—and remains—the perception that some electric utilities poorly planned for, and later mismanaged, their huge investment in nuclear generating capacity. Beginning in the late 1950s, and ending no later than the Three Mile Island incident in 1978, "nuclear" was the fuel of choice and even relatively small capitalized utilities attempted to undertake the responsibility for developing one or more of these costly assets. Several such episodes, involving the Western Public Power Supply System ("WPPSS," and more popularly remembered as "WHOOPS"), Public Service Company of New Hampshire (PSNH), and the El Paso Electric Company, resulted in bankruptcies. The largest share of the stranded costs—that have become a down payment for change—are associated with the above-market fixed and variable costs of nuclear plants, and the closing of the books on this unfortunate legacy.

But high-cost nuclear plants were not the only problem. Other power generating technologies also contributed to the stranded cost problem, albeit for different reasons. PURPA-qualifying generators were an issue because some state energy policies failed to implement the federal law as intended. The intent was to hold retail customers harmless from the displacement of utility generation by more efficient on-site customer generation. Instead, state implementation rules allowed "avoided costs" set at levels that greatly exceeded a utility's actual costs. The avoided costs were typically guaranteed in "standard offer" contracts. The above-market valuation of these contracts became another component of the down payment for change.

Utilities were also under pressure from regulators and environmentalists to increase investments in renewable energy and "demand-side" resources, often as politically motivated retribution for emerging problems associated with nuclear plant financing and construction. The regulatory and siting process in many states was increasingly subject to "capture" by environmental interests.

This is all history. But the legacy of this experience—other than the *Competitive Transition Charge* now paid by at least half the nation's electricity consumers—was a virtual nation-wide moratorium on the construction of new generation by utilities. For example, California maintained a de facto "no build" policy for at least a decade because it believed that conservation could meet all the needs of new demand growth. The slow economic growth of the 1980s, also reflected in lower forecasts of electric demand growth, became the excepted industry norm. The unexpected and sustained economic (and power demand) growth of the 1990s caught many utilities and their regulators sleeping at the wheel. As one state after another enacted legislation to deregulate power generation, a new risk emerged.

New Generation: The Current Predicament

Several regions of the country face shortages of electric generating capacity. There is also growing concern that planned capacity additions may be too dependent on natural gas as the primary fuel. As wholesale and retail power markets become more competitive, any "shortage" becomes a potentially huge political issue because market forces will always force prices to what the market will bear, and flawed market structures can compound such costs. Under traditional regulation, utilities had an inherent incentive (or obligation) to overbuild, and actual power shortages (*i.e.,* failure to serve end-use customers) were invariably associated with major transmission or distribution outages. The rolling blackouts in California were a rude departure from this tradition.

Several regional electricity markets in the United States inherited relative "tight" capacity reserves. Some, like Texas and the Midwest, have made great strives to upgrade the generation resource base necessary to support a competitive market. Others, like the West and Northeast, are still behind.

Barriers to New Generation

The traditional barriers to the construction of powerplants continue in a competitive industry. These include delays in the siting and permitting of new plants, environmental restrictions on fuel choice, land management and water use issues, and increased local opposition to the mere presence of a power plant regardless of the need. In addition, the siting and permitting processes for a new generating plant are exposed to significant delays and other uncertainties if natural gas pipeline and/or transmission capacity constraints also have to be addressed as a pre-condition to the construction and operation of the powerplant.

New barriers include price caps and certain so-called *advantages of incumbency*: (1) discriminatory interconnection policies of transmission utilities with generation affiliates, and (2) subsidization of the fixed costs of existing generators resulting from stranded cost recovery. Barriers associated with price caps and the physical interconnection are serious problems in many regions and have been addressed elsewhere in this paper.

Fuel Diversity

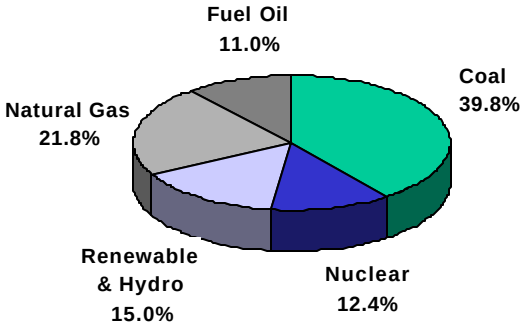
Fuel diversity is protection, as perceived by regulatory bodies or the market, from uncertainties associated with fuel availability, price, reliability of delivery, and regulatory changes. But the developer's choice of a particular fuel to fire a new generating asset is intertwined with the per-kilowatt cost of the generator technology, the expected performance of the technology during its depreciable life, and his or her assessment of the expected risks associated with the fuel, such as availability, price, reliability of delivery, and regulatory changes. This is a complex matrix of economic decisions and tradeoffs that is ideally suited for markets. One definition of competitive markets might be "the open process that best reconciles price, technological, and regulatory risks."

The introduction of competition in the electric industry has already substantially improved the fuel diversity or "generation mix" of the industry. In the totally regulated ("utility")

generation sector, coal and nuclear are the primary fuels accounting for 78% of generation (in kWh). The fast-growing unregulated ("non-utility") generation sector relies on natural gas for over 50% of its generation. Combined, the market shares of each fuel are becoming more evenly spread with coal maintaining the largest share. But these figures reflect national averages. The market shares are different depending upon local access to fuels and environmental restrictions. For example, hydro is prevalent in the Pacific Northwest, natural gas in the Southwest, and coal in the Midwest.

Installed U.S. Generation by Fuel Type

(Source: U.S. DOE, 1999, Summer Capability)



More recently, the debate on "fuel diversity" is directed at the perception that natural gas is the "fuel of choice." Proponents of coal, nuclear, and renewable resources all have their marketing campaigns directed at promoting greater interest in their resources. Certainly, the fact that 93% of planned capacity additions through 2004 will be gas-fired is attributable to the low prices of this fuel in recent years and perhaps a flawed conventional wisdom that "2 dollar" gas would last forever. This does not mean that natural gas is currently over used, or that market corrections will not be forthcoming as relative prices with competing fuel change.

Ideally, competitive markets should dictate fuel diversity provided there are no market distortions that inhibit the markets from efficient choices. The most critical "distortions" are public policies or regulations that needlessly interfere with market choices. These include policies that artificially handicap the choice of coal or nuclear because of unfounded or exaggerated environmental liabilities.

RECOMMENDATIONS:

NEW GENERATION

- Environmental Compliance – Market forces should be allowed to dictate fuel and technology choice decisions subject to applicable Federal and state environmental laws. Federal and state air and water permitting laws should be reformed so as not

to impede the needs of new competitive markets. Guidelines and rules for environmental compliance should be fuel and technology neutral and not attempt to *legislate* policy outcomes that the U.S. Congress, or the relevant state legislature, has not explicitly authorized.

- Siting & Permitting – The siting and permitting procedures for new powerplants should be streamlined and reformed to address the needs of a competitive electricity and natural gas industries. Federal, state, or local (where applicable) siting and permitting regulations should not be used to perpetuate *central planning* approaches (*e.g.,* IRP) to resource decision-making. "One-stop-shopping" permitting processes should operate in fact, as well as, in name.

- Accountability of Regulatory Agencies – Regulatory agencies authorized to administer and enforce air and water quality, land use, or other statutory limitations on the development of new electric generation have a burden to help minimize the compliance costs of applicants and regulatory uncertainties, and to timely execute their responsibilities. The mission of environmental agencies should emphasize solutions (*i.e.,* reconciling conflicting public policy objectives with the application at hand) and not to advocate a particular position on energy policy.

- Price Caps – Any price cap set at or below the level necessary to attract new generation will discourage such investments. Price caps in the form of "circuit breakers" are only justified to prevent market collapse.

FUEL SUPPLY

- While maintaining a balanced sensitivity to environmental needs, access to federally-owned public lands should be reasonably liberalized to the extent necessary to ensure adequate exploration and extraction of primary fuels such as oil, natural gas, and coal, and for the development of non-traditional resources such as geothermal, wind, and solar. Such access must be timely to avoid unnecessary pricing distortions created by short-term scarcity.

FUEL DIVERSITY

- Federal Funding of Energy R&D – Federal support for the research and development of new energy production technologies should be fuel and technology neutral and not attempt to second-guess choices subsequently made in the marketplace. Federal funding should always require co-funding from industry sectors that may benefit from taxpayer support.

- Tax Credits, Subsidies & Portfolio Standards – Federal and state policies to promote the development of new power production investments and associated infrastructure should be fuel and technology neutral and not attempt to "pick the winners."

- Open-access Transmission – An essential federal policy necessary to ensure fuel diversity in the generation of electricity is nondiscriminatory access to transmission service, and the requirement that all users of the transmission system be subject to

the same rates, and terms and condition of service. Fuel diversity is harder to maintain in smaller regional markets, where one or more fuel resources provide disproportionate local economic benefits in the form of jobs and taxes. Existing FERC policies and regulations discourage the free movement of power within an Interconnection that would promote more fuel-on-fuel competition.

- Cogeneration – The cogeneration of steam and electricity in industrial and commercial applications should be encouraged by the removal of all impediments to the development, construction, and interconnection of such assets. This technology is arguably the most efficient and beneficial, in terms of its impact on the economy and the environment.

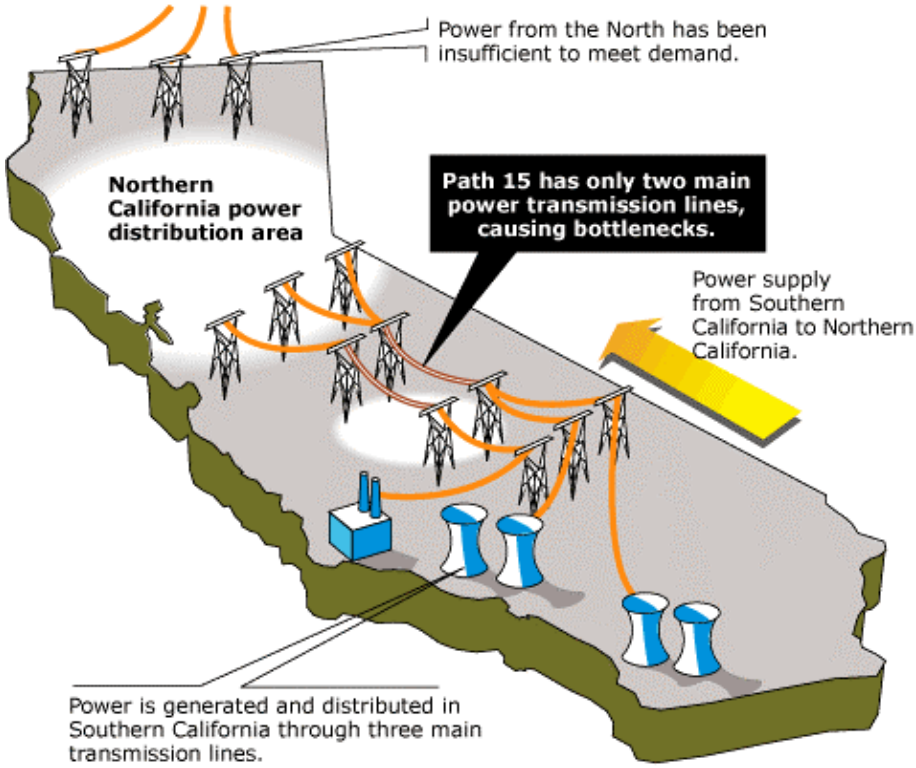
- Nuclear Power – The merits of nuclear power as a viable generating resource deserve reconsideration in the new competitive industry. But any new proposed nuclear plant must be funded in private capital markets and not rate-based.

- Coal – Private and government funding of advanced clean coal technologies (CCT) should be encouraged to leverage the fact that coal remains the country's most abundant and secure energy resource.

- Renewable Resources – No fuel or technology should enjoy a guaranteed market share which is the intended purpose of so-called "portfolio standards" for renewable energy resources. The market for some of these resources should thrive in a competitive marketplace because retail choice will enable customers to bypass traditional one-size-fit-all utility service.

5. NEW TRANSMISSION CAPACITY

One unexpected benefit of the California crisis has been the heightened awareness by that state's press, policy makers, and general public of the importance of transmission capacity for ensuring reliable electricity supply and preventing rolling blackouts. "Path 15" in the state's Central Valley received front-page exposure in all of the state's major newspapers, and this generated widespread political support for upgrading the transfer capability of this critical transmission interface.[21] But other transmission "paths" vital to California's economy are also habitually constrained.



Source: Los Angeles Times

Prudent transmission planning should not have to rely on a "crisis" environment to resolve issues associated with the need for and siting of new or upgraded transmission facilities. The inadequate transmission infrastructure in California was not an unintended consequence of deregulation but the result of the state's prior reliance on the regulatory paradigm most widely known as *Integrated Resource Planning* (IRP).

[21] In January and February 2001, rolling blackouts in the northern part of the state were called by the Cal ISO because this facility was constrained and unable to deliver available generation from Arizona and elsewhere. In previous years, northern California relied on excess generation from the Pacific Northwest to meet its winter peaking needs.

Ongoing problems with the transmission infrastructure are the result of years of neglect. Transmission was the regulated industry's stepchild, and rarely got the attention that utilities gave to generating assets, or that some regulators conferred on demand-side management (DSM) and renewable resources.

NERC's Transmission Adequacy Issues Task Force

The North American Electric Reliability Council (NERC) established the Transmission Adequacy Issues Task Force to identify issues and recommendations pertaining to transmission facility adequacy. The task force's preliminary issues and recommendations are grouped in five key areas: (1) transmission planning, (2) cost recovery, (3) transmission siting, (4) education, and (5) coordination. The task force admitted that each of these issues was "not necessarily new" but that the "changing industry structure provides for a new or different perspective on these issues."[22]

1. Transmission Planning

The NERC task force said that most current transmission projects are driven by localized or regional reliability needs or requirements to connect new independent generators to the bulk-power grid. In part, this results from "the growing tendency to over emphasize the business case for major transmission projects and place less weight on reliability." The transactions in the bulk power markets are overwhelmingly short term in nature, with few commitments for long-term transmission service. Not stated in the task force report is the fact that cost recovery for IPP-driven requests is usually the responsibility of the generator. Investments of the long-term needs of the market, or for reliability, run into the problem of retail rate freezes or caps, and jurisdictional uncertainties.

The NERC task force identified several other planning issues. Transmission margins had become so "thin" that construction outages required to complete some new projects were becoming difficult or impossible to schedule. The increase in the number of requests for interconnection and transmission service were "overwhelming the available manpower resources throughout the industry." Finally, the analytical tools and the expertise to apply the tools were not keeping up with market needs.

2. Cost Recovery

The NERC task force repeated the often-stated utility concern "about the recovery of transmission investment at a fair rate of return." It also identified the risk of "regulatory disallowances" and unclear responsibilities for ultimate payment for transmission additions and upgrades as other disincentives to new construction. The task force report did not discuss the roles played by retail rate freezes, or rate caps, and the refunctionalization of transmission assets in response to RTO formation, on cost recovery. Both actions were often advocated by the utilities.

[22] North American Electric Reliability Council, "Preliminary Issues and Recommendations Pertaining to Transmission Facilities," Report to the Planning Committee, Prepared by the Transmission Adequacy Issues Task Force, March 7, 2001. ELCON's recommendations adopt some of the task force's recommendations.

3. Transmission Siting

The NERC task identified siting issues as "significant obstacles" to the construction of new transmission facilities. This includes the difficulties associated with acquiring regulatory approval and the right-of-way for trans-mission lines. Right-of-way is often strongly opposed by landowners and public interest groups. The report also identified the

> … failure of the project sponsors to clearly define the need and justification of transmission to the regulatory and public entities leads to controversial situations. These issues become even more imposing to address when transmission lines cross over state or international boundaries, where several regulatory bodies, each with different perceptions of the project need and usefulness, are involved.

4. Education

The NERC task force spreads the blame for "lack of understanding" or "expertise" involving transmission projects across the entire spectrum of industry participants—"from the planners to the users." It singled out investment bankers in particular for failing to appreciate the viability of new projects.

The report stated that local, state, and Canadian provincial regulatory agencies lacked engineering expertise and did not have adequate knowledge of deregulation and FERC orders and their impacts on transmission.

The task force faulted the transmission providers themselves for inadequately educating the public, regulators, and administrative law judges (ALJs) "on the complexities, constraints, and consequences associated with transmission and generation adequacy, power system expansion, electricity market structure, and new and expanding market forces."

5. Coordination

Coordination—a uniquely NERC word because the organization has no statutory authority to enforce compliance with its reliability standards—involves the negotiated adoption of, and compliance with, often obtuse engineering specifications associated with maintaining the electrical integrity of a huge electrical circuit (an Interconnection) with multiple owners and operators. Using an automobile as an analogy, ten people attempting to steer a single vehicle at the same time must "coordinate" their activities to prevent the vehicle from crashing.

To coordinate efforts to ensure greater transmission adequacy, the NERC task force believes that "a wide range" of stakeholder interests should be involved in the planning process. But issues that will be especially difficult to coordinate are: (1) the need to plan outages to accommodate new transmission reinforcements; (2) "seams" problems at the boundaries between transmission systems and RTOs; (3) differences among the requirements of neighboring states (and Canadian provincial bodies); and (4) the uncertainties with respect to evolving RTO structures and participants.

Incentives for New or Upgraded Transmission Facilities

The NERC task force did not explicitly address the issue of financial incentives or performance-based regulation (PBR) to encourage the development of new or upgraded transmission facilities. In its defense, NERC or any of its committees, subcommittees, or task forces cannot advocate (or oppose) any policy that would take money out of one NERC participant's hand and give it to another participant.

Any incentive given to a monopoly supplier is a *non sequitur*. A monopolist's status as the only game in town gives it a unique advantage when offered an incentive to induce some desired behavior, it can simply hold out for a better offer. Incentives are only sustainable in competitive markets where more than one supplier is eligible to respond to the incentive. Some regulators may argue that their oversight role can substitute for this market discipline by the threat of explicit penalties for any failure to meet targeted performance improvements. This may be true for a couple of years, but regulated utilities outlive the typical regulatory commissioner by many years (or generations). Regulation is inherently a political process and not a viable surrogate for a competitive market. Regulatory agencies should accept the limitations of imperfect regulation, and work within the *second-best* confines of cost-of-service principles.

RECOMMENDATIONS:

- Obligation to Serve – The Federal Energy Regulatory Commission (FERC) should establish a binding *obligation to serve* for its jurisdictional transmission providers to ensure that new additions and upgrades to the interstate transmission system are prudently planned for, and developed, to maintain short and long-term reliability.

- Mandatory Planning Margin – Major transmission projects should be developed with sufficient margin to provide capacity beyond the current three to five year planning horizon and to conserve valuable right-of-way corridors. Such margins should include the use of larger conductors, double circuit lines, and designs for higher voltage operation.

- Role of RTOs – As required under FERC Order 2000, RTOs should play a major role in the planning of new and upgraded transmission facilities. In many respects, RTOs will replace the traditional utility. However, RTOs are still under development and this will unavoidably delay ongoing planning initiatives.

- Free Entry to Transmission Construction – Enactment of the Public Utility Regulatory Policies Act (PURPA) in 1978, and Title III of the Energy Policy Act of 1992, demonstrated that unregulated generators (*i.e.,* generators exempt from traditional regulation under federal and state laws) provided an economically viable alternative to rate-based utility generation. The same concept should be tested with transmission assets. However, certain pre-conditions may be necessary to fairly validate this concept: competitive bidding and the existence of a robust secondary market for physical transmission rights, for example.

- Level Playing Field – All users of an interconnected transmission system should be subject to the same rates, and terms and conditions, for regulated transmission service. This requires the long overdue abolishment of the so-called "native load exemption" that gives generation and merchant affiliates of a transmission provider preferential access to transmission services.

- Cost Recovery of Projects Needed for Reliability – Regulated transmission providers are entitled to a reasonable opportunity to recover all cost associated with their prudently incurred investments, plus a return on such investments, as long as such assets are deemed used and useful. In the past, this time-honored principle of *cost-of-service* regulation afforded the common stocks of utilities the same investment status as bonds, which did not prevent the financing of the existing transmission infrastructure.

- Cost Recovery of Projects Needed to Expand Transfer Capability – All market participants should be allowed to invest in transmission upgrades that increase transfer capability and retain the transmission rights and/or congestion revenues in proportion to the amount of capacity created by their investment. Any transmission rights may be released into the secondary markets. Such projects should rely on private capital and should not be rate-based. It is appropriate for FERC to treat such projects with light-handed regulation and not subject such facilities to prudence reviews. The project owners and investors may also negotiate with the developer some form of performance contract with milestones and incentives (rewards and penalties).

- Federal Siting Authority – Congress should delegate to FERC the same authorities under the Federal Power Act with respect to the siting of interstate transmission facilities as FERC is currently authorized under the Natural Gas Act with respect to the siting of interstate natural gas pipeline facilities.

6. RTOs: Regional Transmission Organizations

A competitive electric industry requires independent system operators for the same reason independent air traffic controllers exist in the airline industry. Any commercial conflict of interest can compromise safety and reliability as well as create an unfair competitive advantage. Pursuant to FERC Order 2000, Regional Transmission Organizations or RTOs are under development in most parts of the country. It is an open question whether any of these entities are suitable end-state structures for the new industry. Many are too small and incompatible with existing market trading patterns, or fail to meet any reasonable definition of independence.[23]

The power crisis in California is noteworthy in that a FERC-approved ISO was a major player in the ongoing crisis. This created an unexpected opportunity to test the merits of the ISO's operational control. The CAISO had many features of a RTO, and certain features that were missing, have since been added. In a crisis with no end of bad news, the CAISO's performance during the emergency was notably positive.

The crisis provided the following lessons associated with RTO formation:

- Independence – As soon as the crisis began in mid-2000, the merits of the CAISO's stakeholder board were called into question. In the emergency, the stakeholder board was paralyzed by conflicts of interest. Under FERC order, an independent board was established.

- Operational Authority & Short-term Reliability – The CAISO managed to "keep the lights on" for three large utility systems for 32 consecutive days of Stage 3 emergencies when reserves were less than 1.5%. It is inconceivable that the three large California utilities, acting in their own selfish interests, could have done the same.

- Tariff Administration & Design; OASIS & Calculation of TTC and ATC – The CAISO performs these functions and while just about everything that could go wrong, did go wrong, these were not some of them. The central administration of open-access tariff provisions under the ISO's OASIS probably helped bring resources quickly into the market.

- Congestion Management – Congestion management was not a problem in this crisis but the obvious limitations of certain transmission interfaces (*e.g.,* Path 15) became household words and there is now growing in-state political pressure to expand much need transmission capacity.

[23] For a detailed discussion of ELCON's position on RTOs, see Profiles in Electricity Issues: Regional Transmission Organizations (Electricity Consumers Resource Council, Washington, D.C., March 1999) at www.elcon.org.

- Market Monitoring – Fundamental market flaws were evident as soon as the California markets began operation in 1998. The ISO Board's Market Surveillance Committee (MSC) repeatedly warned the Board (and FERC) of the potential for a crisis. Neither the stakeholder board nor FERC acted on these warnings.[24] The MSC had also warned FERC and the ISO of the market design flaw created by the absence of adequate demand response in the California market structure.

- Interregional Coordination – There is a long history of regional cooperation in the Western Interconnection that is generally absent in the Eastern Interconnection. For example, the Western Systems Power Pool (WSPP) experiment gave many control area operators experience with quasi-market interchange transactions. The Western Interconnection is also a single NERC regional reliability council. Hence, there is less Balkanization in western power markets, notwithstanding California's single-state ISO. During the crisis, the ISO faced fewer market barriers to the physically available resources. While this did not make up for the lack of adequate resources to meet demand during all contingencies, the case can be made that it substantially reduced the overall damages of the crisis.

What are the major lessons from the California crisis that bear most on RTO formation in general? First, and foremost, while the CAISO's original market design contributed to the crisis, the ISO's *operational control of transmission assets* helped manage the crisis over a huge regional market. This is a potential benefit that all RTOs can provide. The air traffic controller analogy is most relevant on this issue. During a severe weather contingency, somebody has to sort out the mess on a fair and nondiscriminatory basis. The crisis also exposed the failings of "ISO" structure vis-à-vis "RTO" structure. To its credit, FERC has addressed some of the needed changes. Removing transmission tariff administration, and the transmission reservation and scheduling process, out of utility control prevented "access" issues from making this crisis a true calamity. The absence in the West of the Balkanization that dominates the Eastern Interconnection (*e.g.,* eight regional reliability councils) demonstrates the superior merits of multi-regional RTOs that ultimately replace regional reliability councils. Finally, the market flaws inherent in the California market's original design were known before the crisis materialized. This demonstrates that it is not sufficient to establish "market monitoring units" as FERC Order 2000 requires. There must be an audience for any warning, and that audience must be required to act.

RECOMMENDATIONS:

- Minimize Number of RTOs – A single, independent RTO should be established in each of the three interconnections. Each RTO should replace the incumbent NERC regional reliability council or councils. Independent transmission companies (transcos) should be subject to the operational control of an independent RTO.

- Interregional Coordination – Where multiple RTOs are allowed to coexist within an interconnection, it is critically important that each RTO's reliability and market

[24] See Market Surveillance Committee of the California Independent System Operator, "The Competitiveness of the California Energy and Ancillary Services Markets," March 9, 2000

interface practices are compatible with each other, particularly with regard to transactions across the boundaries ("seams") of adjacent RTOs. The integration of reliability practices involves procedures for coordination of reliability practices and sharing of reliability data among RTOs in an interconnection, including procedures that address parallel path flows, ancillary service standards, transmission loading relief procedures, and other reliability-related requirements in Order 2000. The integration of market interface practices involves developing some level of standardization of inter-RTO market standards and practices, including the coordination and sharing of data necessary of the calculation of TTC and ATC, transmission reservation and scheduling practices, congestion management, and other market coordination requirements in Order 2000.

- Establish New Function 9 for Customer Load Curtailment (CLR) Service – Competitive markets cannot operate without a demand response in the wholesale spot (and forward) markets. Since RTOs are required to operate the real-time markets, FERC Order 2000 should be amended to establish a new Function 9 requirement to ensure that markets of Customer Load Curtailments (CLR) services are integrated with the other RTO real-time markets. This would also ensure that such markets are reasonably standardized each interconnection. Participation in the CLR market should be voluntary and open to any customer (with or without an aggregator or other intermediary).

- Market Surveillance – Any market operated by a RTO, or on behalf of a RTO, should be subject to an independent market surveillance function to monitor such markets for potential design flaws, gaming behavior, and the exercise of vertical, horizontal, or localized market power. This includes markets for transmission services, ancillary services, and power exchanges. This function should not, and need not, extend to the monitoring of power exchanges (and other web-based trading platforms) that are independent of RTOs or bilateral transactions in which the RTO is not a party.