UTAH STATE BAR
ENERGY, NATURAL RESOURCES AND ENVIRONMENTAL LAW SECTION

Energy Committee

Selected Developments 2016-2017

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I. NOTABLE JUDICIAL DECISIONS

A. United States Court of Appeals for the District of Columbia Circuit

1. NextEra Desert Ctr. Blythe, LLC v. Federal Energy Regulatory Comm'n, No. 16-1003 (DC Cir. April 4, 2017).

This case concerns two solar power plants in the California desert—the Genesis solar plant in Desert Center and the McCoy solar plant near Blythe—and a transmission project that connects them with customers in southern California. Prior to completion of the two facilities, Genesis and McCoy entered into long-term agreements to sell their power to electric utilities, including Southern California Edison Company ("SoCalEd"). NextEra Desert Center Blythe, LLC ("NextEra") was then formed to connect Genesis and McCoy to the grid. NextEra, SoCalEd and the California Independent System Operator ("CAISO") reached an agreement to govern the interconnection of Genesis and McCoy to the CAISO-controlled grid. This Interconnection Agreement identified the need for high-voltage transmission upgrades, known as the West of Devers Upgrades.

NextEra grew concerned that the permanent West of Devers Upgrades would not be completed in time for it to meet its obligations to the electric utilities. CAISO and SoCalEd identified a temporary fix known as the Interim Project. NextEra committed to the Interim Project, with SoCalEd responsible for construction and NextEra footing the bill.

In December 2014, CAISO informed NextEra that it planned to release Congestion Revenue Rights ("CRRs"). CRRs arise from CAISO's method for setting wholesale electricity prices, which builds the cost of congestion into the price of energy. NextEra informed CAISO that, in its view, it was entitled to receive the CRRs associated with the Interim Project under section 36.11 of CAISO's tariff. CAISO and SoCalEd disagreed. NextEra filed a complaint with FERC asking that the Commission direct CAISO to allocate it the CRRs.

The Commission denied NextEra's complaint. According to FERC, the terms of the Interconnection Agreement clearly and unambiguously bar NextEra's attempt to receive CRRs under CAISO tariff section 36.11. Given this interpretation, FERC declined to address whether NextEra would otherwise be entitled to CRRs under CAISO tariff section 36.11.

If FERC's decision rests on an erroneous assertion that the plain language of the relevant wording is unambiguous, the Court of Appeals must remand to FERC so that it may consider the question afresh in light of the ambiguity the court sees. In this case, the Court of Appeals found ambiguity where FERC found none.

FERC's argument was that under the Interconnection Agreement, NextEra was entitled to a refund for Network Upgrades. It argued that the Interconnection Agreement provides that CRRs under the tariff are available only as an alternative to a refund for Network Upgrades. The Interim Project is not a Network Upgrade, so NextEra is ineligible for CRRs in connection with the Interim Project.

The Interconnection Agreement states that NextEra may elect to receive CRRs in lieu of a refund of the cost of Network Upgrades. FERC interpreted this to mean that NextEra may receive CRRs only if it is eligible for a refund for a Network Upgrade. But, the Court ruled that the only thing that was clear was that one could not receive both CRRs and a refund for Network Upgrades. This does not unambiguously mean that the lone avenue for receipt of CRRs is by way of a Network Upgrade.

NextEra believes that section 36.11 of the CAISO tariff offers another way to obtain CRRs for the Interim Project. However, because of its finding of unambiguity, FERC did not address this question. The Court states that it is a well-worn principle that reviewing courts may affirm an agency order based only on reasoning set forth by the agency itself. Since FERC did not reach the tariff interpretation, the Court declined to reach issues of tariff interpretation without first receiving the benefit of FERC's considered judgment. Therefore, the matter was remanded to FERC for further proceedings consistent with this opinion.

2. Petro Star Inc. v. Federal Energy Regulatory Comm'n, No. 15-1009 (DC Cir. Aug. 30, 2016).

The Trans Alaska Pipeline System ("TAPS") is the sole means of transporting oil from Alaska's North Slope to the shipping terminal at Valdez, Alaska, roughly 800 miles to the south. Oil companies deposit crude oil extracted from their fields on the North Slope into the pipeline at its northern point. Although the companies' crude oil deposits differ in ways that affect their respective market values, the deposits necessarily become commingled in the pipeline. At the southern end of the pipeline in Valdez, the oil companies receive the same proportion of oil they initially contributed to the common stream. Because of the commingling, however, the companies generally will not receive the same quality of oil at Valdez that they initially delivered into the pipeline at the North Slope. To avoid companies getting a value at the south end different from what they deposited at the north end, a mechanism for calibrating payments known as the Quality Bank ("QB") was established by FERC. The QB assigns each company's crude oil a value based on the quality of its components or "cuts."

Since 1993, the QB has used the "distillation method" to calculate the monetary adjustments. Distillation is the initial step in the oil refining process. It involves the separation of crude oil into different components or "cuts" through heating and boiling. There are nine cuts. The QB assigns a value to each of the nine distillation cuts and determines how much of each cut makes up the crude oil streams deposited by an oil company into the TAPS. It then calculates the value of each company's crude oil contribution based on the volume-weighted value of its component cuts. The same formula determines the value of the commingled common stream. Oil companies make payments into or receive payments from the QB based on the difference in value between the oil they deliver into the pipeline and the common stream they ultimately receive at Valdez. The proper functioning of the QB depends on assigning accurate relative values to the nine distillation cuts.

Under its current approach, the QB aims to assign a value to each cut reflecting its actual market price as closely as possible. Six of the cuts can be sold following distillation without any additional processing, and they have published market prices. That is what the QB uses to value those six cuts. The published market prices for those six cuts are assumed to include the refining cost of producing the cut. The remaining three cuts cannot be sold without additional processing following distillation and have no published market prices.

The lowest cut, Resid, with additional refining, can be developed into coke and coke has a published market price. Under the current QB methodology, Resid's value equals the market price of coke minus the processing cost required to convert Resid into coke. The cost deduction for Resid includes a 20% capital recovery factor (capital investment allowance).

The current formula was adopted in a 2004 agency hearing. In 2013, FERC initiated its own investigation into the QB methodology to determine if it was still just and reasonable. Petro Star, a refiner along the TAPS, intervened, arguing that the 20% capital allowance should be removed because it resulted in a valuation incommensurate with the prices of the six marketable cuts. The ALJ rejected this argument for two independent reasons: (i) they had failed to propose a just and reasonable alternative to the existing QB method; and (ii) they failed to demonstrate that it was unjust and unreasonable to include a capital investment allowance in Resid's processing cost adjustment. The Commission affirmed the ALJ's opinion.

The Court concluded that Petro Star established a prima facie case that new evidence warrants re-examination of the QB formula to value Resid. The Commission was obligated to offer a meaningful response to Petro Star's arguments but failed to do so. Therefore, its decision was arbitrary and capricious. The Commission must either answer the objection to the Resid methodology or change its formula.

Moreover, the Commission initiated the proceedings below as an investigation into the lawfulness of the existing QB methodology, in particular, its valuation of Resid. Therefore, Petro Star's alleged failure to suggest a viable alternative proposal cannot serve as an independent ground for the Commission's decision. The Commission must, on remand, provide a meaningful response to the new evidence presented by Petro Star.

3. Oklahoma Gas & Elec. Co. v. Federal Energy Regulatory Comm'n, No. 14-1281 (July 1, 2016).

Until recently, incumbent public utilities were free to include in their tariffs and agreements the option to construct any new transmission facilities in their particular service areas, even if the proposal for new construction came from a third party. Pursuant to Order 1000, the Commission ordered utilities to remove these rights of first refusal from their existing tariffs and agreements. The Commission had reserved judgment on whether to apply this presumption to remove the rights of first refusal until evaluating the individual utilities' compliance filings. Upon the Southwest Power Pool's compliance filing, FERC has determined to remove the rights of first refusal and parties petitioned for review, arguing that the *Mobile-Sierra* doctrine protects their right of first refusal.

No matter the contract provision at issue, even if the *Mobile-Sierra* doctrine might apply to it generally, FERC did not err in determining that the doctrine does not extend to anti-competitive measures that were not arrived at through arms-length bargaining. Just as unfair dealing, fraud, or duress will remove a provision from the ambit of *Mobile-Sierra*, so also will terms arrived at by horizontal competitors with a common interest to exclude any future competition. The court denied the petition and affirmed FERC.

On April 18, 2017, the U.S Court of Appeals for the D.C. Circuit also denied challenges by several New England power companies and five state regulators to the implementation of Order 1000's elimination of the right of first refusal. The cases, which were consolidated, were *Emera Maine v. FERC*, No. 15-1139, *NESCOE v. FERC*, No. 15-1141.

4. United Airlines, Inc. v. Federal Energy Regulatory Comm'n, No. 11-1479 (July 1, 2016).

SFPP is a Delaware limited-partnership, common-carrier oil pipeline. The pipeline transports refined petroleum products from California, Oregon, and Texas to various locations throughout the southwestern and western United States. On June 30, 2008, SFPP filed tariffs to increase rates on its West Line, which transports petroleum products throughout California and Arizona. On that date, SFPP made a separate tariff filing to decrease the rates on its East Line, which runs from West Texas to Arizona. The purported impetus for these filings was increased throughput on SFPP's East Line due to a recently completed expansion, which accordingly decreased throughput on the West Line. Several shippers protested the West Line tariff filing by raising challenges to SFPP's cost of service.

SFPP makes two arguments in its petition. First, it claims that FERC arbitrarily or capriciously failed to utilize the most recently-available data when assessing its so-called real return on equity. Second, SFPP asserts that FERC erred when it declined to apply the full value of the Commission's published index when setting SFPP's rates for the 2009 index year. The Shippers raise a separate challenge to FERC's current policy of granting to partnership pipelines an income tax allowance, which accounts for taxes paid by partner-investors that are attributable to the pipeline entity. Because FERC's ratemaking methodology already ensures a sufficient after-tax rate of return to attract investment capital, and partnership pipelines otherwise do not incur entity-level taxes, FERC's tax allowance policy permits partners in a partnership pipeline to "double recover" their taxes.

SFPP also challenges as arbitrary or capricious FERC's reliance on cost-of equity data from September 2008 when calculating SFPP's so-called "real" return on equity and the Commission's rejection of more recent data from April 2009. FERC argues in response that the more recent cost-of-equity data "encompassed the stock market collapse beginning in late 2008," and was therefore anomalous. The court agreed that FERC had substantial evidence to support its determination that the 2009 data did not reflect SFPP's long-term cost of equity. However, because the Commission provided no reasoned basis to justify its decision to rely on the September 2008 data, the court held that the Commission engaged in arbitrary or capricious decision-making and therefore granted SFPP's petition, vacated FERC's orders with respect to this issue and remanded.

At a general level, FERC's indexing methodology directs pipelines to file initial rates, usually reflecting their costs-of-service. Based on the initial rate filings, FERC then calculates rate ceilings for future years based on the change in the Producer Price Index for Finished Goods. The index establishes a ceiling on rates, not the rate itself.

In this case, SFPP filed cost-of-service rates, effective August 1, 2008, proposing to increase the rates charged on its West Line. Because this rate took effect during the 2008 index year, it also constituted the applicable ceiling level for that index year. To compute the ceiling level for the 2009 index year, SFPP multiplied the previous index year's 2008's ceiling level by the most recent index published by FERC, which was 7.6025 percent. Protestors argued that because the 2009 index is based on FERC's computation of industry-wide cost increases between 2007 and 2008, SFPP should not be permitted to double-recover its costs by combining its 2008 cost-of-service rates with proposed 2009 indexed rates. The Shippers alleged that SFPP's 2009 indexed rate increase was substantially in excess of the actual cost increases incurred by SFPP. FERC agreed. Because a protest was filed, FERC's regulations state that the Commission will compare the actual cost increases incurred by the carrier with the proposed rate increase. When FERC made this comparison it noted that SFPP would effectively double-recover its 2008 costs were it to receive the full 2009 index. FERC provided sufficient justification for its decision to reduce SFPP's 2009 index to one-quarter the published value and the court denied SFPP's petition on this issue.

The Shippers noted that, as a partnership pipeline, SFPP is not taxed at the pipeline level and because FERC's discounted cash flow return on equity already ensures a sufficient after-tax return to attract investment to the pipeline, they argued, the tax allowance results in double recovery of taxes to SFPP's partners. FERC argued that the court already decided this issue in *ExxonMobil* and this is a collateral attack to that decision.

While the court did not expressly reserve the issue in the *ExxonMobil* opinion, the fact that in that case FERC averred during briefing and in an accompanying case that it was addressing the double recovery issue in a separate proceeding, reflects the court's implicit reservation of the question. The court held in *ExxonMobil* that, to the extent FERC has a reasoned basis for granting a tax allowance to partnership pipelines, it may do so. The Shippers now challenge whether such a reasoned basis exists based on grounds that FERC agreed were not at issue in the prior case. The court therefore held that the Shippers' petition was not a collateral attack on that decision. The court further held that FERC had not provided sufficient justification for its conclusion that there is no double recovery of taxes for partnership pipelines receiving a tax allowance in addition to the discounted cash flow return on equity and remanded for further proceedings.

5. BP Energy Co. v. Federal Energy Regulatory Comm'n, No. 15-1205 (July 15, 2016).

Prior to 2002, the providers of both LNG terminal services and interstate natural gas pipeline services were regulated under the Natural Gas Act ("NGA") § 7 and were traditionally required to do so at cost-of-service rates and under open access terms of service. In 2002, upon determining that the traditional approach may have had the unintended effect of deterring new investment, the Commission announced a less intrusive regulatory regime for LNG terminals under NGA § 3. This approach was effectively codified by the Energy Policy Act of 2005. As a result, LNG terminals are no longer required to offer open access terminal services at cost-based rates and instead may contract with customers for terminal services based on market-based rates. It also provides protections for existing customers receiving service under NGA § 7 against cost-shifting, degradation of service, and undue discrimination. The Commission still remains responsible for ensuring that the rates at which facilities provide terminal services to open access customers and other services, such as pipeline services, are just and reasonable, do not reflect any undue preference or advantage, and are publicly disclosed in the facility's tariff.

BP Energy ("BP") receives pipeline and terminal services as an import customer of the Cove Point LNG facility under a contract with the facility's owner, Dominion. In 2012, Dominion held a reverse open season that extended the opportunity to turn back contracted-for pipeline services to its NGA § 7 pipeline customers in order to free up pipeline capacity in support of its plans to convert the Cove Point facility from an import maritime terminal to a mixed-use, import and export terminal. After receiving no requests, Dominion negotiated an agreement with Statoil to turn back the entirety of its NGA § 7 pipeline and NGA § 3 terminal services.

BP filed a protest to the turn back agreement with Statoil claiming it was unduly discriminatory because it allowed Statoil to turn back both pipeline and terminal services, an opportunity that was not extended during the reverse open season. FERC concluded the turn back agreement was not unduly discriminatory under NGA § 3 because it did not change the terms and conditions of terminal service for BP and because BP and Statoil were not similarly situated.

BP contends that the Commission's interpretation of "terms or conditions of service at the facility" is an unreasonable reading of the clear text of NGA § 3. The court ruled that the Commission has not adequately explained the reasoning of its interpretation. The Commission assumes its interpretation is the true meaning without even acknowledging that it is an interpretation. BP's petition is granted on this issue.

The Commission maintains that its refusal to order Dominion to offer BP a full turn back opportunity should be affirmed on the alternate ground that BP and Statoil are not similarly situated because BP receives greater regulatory protections as an NGA § 7 customer than does Statoil as an NGA § 3 customer. However, the Commission has not adequately explained why these protections provide a rational basis for permitting the turn back agreement only to Statoil. Therefore, the issue must be remanded for further explanation.

B. United States Court of Appeals for the Tenth Circuit

1. Buccaneer Energy (USA) Inc. v. Gunnison Energy Corp., No. 15-1396 (Feb. 3, 2017).

This antitrust case arises from a series of interactions among one incipient and two established natural gas producers in a portion of western Colorado known as the Ragged Mountain Area ("RM Area"). Buccaneer Energy (USA) Inc. ("Buccaneer") sued SG Interests I, Ltd., SG Interest VII, Ltd. (together "SG"), and Gunnison Energy Corporation ("GEC") (collectively "Defendants") after unsuccessfully seeking an agreement to transport natural gas on Defendants' jointly owned pipeline system at a price Buccaneer considered reasonable. Buccaneer alleged that by refusing to provide reasonable access to the system, Defendants had conspired in restraint of trade and conspired to monopolize in violation of § 1 and § 2 of the Sherman Act.

The district court granted summary judgment to Defendants, concluding that Buccaneer could not establish either of its antitrust claims and that, in any event, Buccaneer lacked antitrust standing. The Tenth Circuit agreed that Buccaneer failed to present sufficient evidence to create a genuine issue of fact on one or more elements of each of its claims, and therefore affirmed on that basis alone.

Section 1 of the Sherman Act prohibits every contract, combination in the form of trust or otherwise, or conspiracy, in restraint of trade or commerce among the several States. Despite its semantic breadth, § 1 has long been construed to outlaw only concerted conduct by two or more separate entities that unreasonably restrains trade. A plaintiff must prove not only the existence of an agreement or conspiracy between two or more competitors to restrain trade, but also that the restraint is unreasonable. The Tenth Circuit focused on the latter requirement in this case.

There are two main analytical approaches for determining whether a defendant's conduct unreasonably restrains trade: the per se rule and the rule of reason. Buccaneer has advanced only the rule of reason.

Under the rule of reason, the plaintiff bears the initial burden of showing that an agreement had a substantially adverse effect on competition. If the plaintiff meets this burden, the burden shifts to the defendant to come forward with evidence of the procompetitive virtues of the alleged wrongful conduct. If the defendant is able to demonstrate procompetitive effects, the plaintiff then must prove that the challenged conduct is not reasonably necessary to achieve the legitimate objectives or that those objectives can be achieved in a substantially less restrictive manner. Ultimately, if these steps are met, the harms and benefits must be weighed against each other in order to judge whether the challenged behavior is, on balance, reasonable.

There are several ways to establish that an alleged restraint has or is likely to have a significant anticompetitive effect. First, under the abbreviated, quick look rule-of-reason analysis, courts simply assume the existence of anticompetitive effect where the conduct at issue amounts to a naked and effective restraint on price or output that carries obvious anticompetitive consequences. Under this analysis, the burden immediately shifts to the defendant to demonstrate countervailing procompetitive effects.

Second, a plaintiff may directly establish anticompetitive effect by showing that the defendant has actually reduced output or raised prices. Third, a plaintiff may attempt to indirectly establish anticompetitive effect by defining a relevant product and geographic market and showing the defendant possesses market power in that market.

There is no evidence of any effect on either of the markets that Buccaneer has identified, let alone an anticompetitive one. Also, Buccaneer has not presented any evidence that fewer production rights have been acquired in the RM Area or that Defendants' alleged monopsonist position has allowed them to pay less-than-competitive prices for such rights. Similarly, Buccaneer has shown neither an actual increase in the price paid for natural gas nor an actual reduction in the amount of natural gas sold.

To demonstrate market power, a plaintiff must identify a relevant market in terms of both product and geographic area. Once a legally sufficient market has been identified, the plaintiff must show market power, which entails demonstrating that the defendant has either power to control prices or the power to exclude competition. Buccaneer did not adequately identify a relevant product market or one in terms of geographic area.

Even if it had identified the relevant markets, Buccaneer was unable to show Defendants possessed market power. To demonstrate market power a plaintiff may show evidence of either power to control prices or the power to exclude competition. Buccaneer was unable to present evidence of either.

C. United States Court of Appeals for the Seventh Circuit

1. Benton County Wind Farm LLC v. Duke Energy Indiana, Inc., No. 15-2632 (Dec. 6, 2016).

In 2005, Duke Energy Indiana ("Duke") offered to buy 100 MW of renewable energy at a price high enough to enable potential sellers to finance the construction of wind turbines. As part of the deal, Duke would acquire renewable-energy credits that buyers or generators of wind energy can trade or sell to other utilities that lack wind generation. The contract between Duke and Benton requires Duke to pay Benton for all power delivered during the next 20 years and requires Benton to deliver to lines owned by Northern Indiana Public Service Company ("NIPSCO") or some other place designated by the regional transmission organization ("RTO"), the Midcontinent Independent System Operator ("MISO").

RTOs generally use the price system to balance loads on their networks. Potential buyers of energy bid for power to be delivered over the network and potential sellers such as Duke (on behalf of Benton) submit bids for sales, and the RTO accepts the bid that clears the market.

When Benton's wind farm started producing, the bidding was conducted once a day. Now it is conducted every five minutes by computers. MISO uses a variant of a Vickrey auction to decide which bids are accepted at what price.

For some kinds of suppliers, such as wind farms, the marginal cost of generating any unit of output is small, even though the capital cost of building wind turbines is high. When Benton started operating it was the only wind farm in the area, and NIPSCO's facilities could carry its entire output. Duke purchased and paid for everything Benton could produce and MISO cleared the transfers to the regional grid. By 2015, the aggregate capacity of local wind farms was 1745 MW, and more wind farms are being built. The capacity of the local transmission grid has been exceeded. It is no longer possible for all of the local wind farms to generate power at the same time, because the grid cannot accept their full output. Because local generation capacity substantially exceeds local transmission capacity, the market-clearing price in MISO's auction has fallen and is sometime negative. Prices near or below zero induce some producers to stop supplying electricity and thus reduce output to what the grid can carry.

Until the end of 2013, MISO allowed wind farms to deliver to the grid no matter what other producers were doing, which meant that other classes of producers had to cut back. Sometimes the market price in this must-carry-wind-power system fell below zero, which meant that wind generation alone had overtaxed the local grid. When that happened, Duke paid a negative price, displacing other wind farms to ensure that Benton ran at capacity. So, if the auction price was minus $10/MWh, Duke would pay MISO that amount and pay Benton for the power; it would receive nothing for this power (save the renewable energy credits) and charge the loss to its customers. Duke could recover some of the loss in its role as a buyer of power from MISO's grid, because even if the power on NIPSCO's grid goes north (and Duke's operations are in southern Indiana), a lower price on NIPSCO's network will depress prices on other grids, which will buy from NIPSCO and tell other sources to curtail their own output. But Duke believes that it loses more in its role as seller of Benton's power than it gains in its role as buyer from MISO.

On March 1, 2013, the rules changed to put wind farms constructed after 2005 on a par with other classes of producers. Benton lost its status as a must-run facility. Duke responded to the new system by deciding to bid exactly $0, all the time, to put Benton's power on the grid. When this bid is accepted, Duke gets the market-clearing price (usually positive but sometimes zero) and pays Benton the contract price (roughly $52 per MWh). But when the market-clearing price in MISO's auction falls below $0, and Duke's bid therefore is rejected, MISO instructs Benton not to deliver any power. Once Benton generates power it must deliver it (otherwise it would fry its own equipment), so an order not to deliver power equates to an order not to generate power, and Benton must stop its turbines from rotating. Under MISO's new system, with Duke's standing bid of $0/MWh, Benton has gone from delivering power 100% of the time the wind allowed to delivering (and being paid) only 59% of the time that the weather can drive its turbines at their capacity.

In this litigation Duke takes the position that, when MISO tells Benton to stop delivering power, Duke does not owe Benton anything. Benton takes the position that Duke could put Benton's power on the grid by making a lower bid (MISO accepts bids as low as negative $500 per MWh), thereby displacing other producers' power, and that when Duke elects not to do this it owes liquidated damages under the contract. Sometimes for load-balancing or other technical reasons MISO tells Benton to stop delivering power even when the market price exceeds zero and Duke's bid nominally has been accepted. Benton acknowledges that in this situation Duke need not pay damages.

The district court sided with Duke, ruling that Duke need pay only for power delivered to the "Point of Metering" where it is measured and passes to the local grid; when MISO issues a stop order that quantity is zero.

The dominant principle is that courts follow contractual language unless ambiguity permits the use of parol evidence. The parties agree that this contract is clear (though not on what it means), and the court also determined it unnecessary to go beyond the document's language.

Benton claims there is a take-or-pay clause, requiring Duke to pay for energy whether taken or not. The court disagreed. The court reasoned that otherwise it would require Duke to pay Benton even if the reason for non-delivery is an instruction that MISO issues independent of how much Duke bid in the auction and independent of how much transmission capacity is available. MISO might issue such an order if, for example, there is a decline in demand on the buyers' side of the market or a technical fault in some other grid, which cannot accept as much power from NIPSCO's lines. Yet Benton conceded that Duke need not pay when it receives such a stop order.

Duke says, without contradiction from Benton, that the market-clearing price is positive 80% of the time and Duke's $0 bid thus is accepted, but the fact that MISO allowed Benton to generate power only 59% must be attributable to MISO's decision rather than Duke's bid. If Duke need not pay Benton for energy when MISO's choices, alone, account for non-generation, the clause cannot be a standard take-or-pay clause.

But the opposite view is not true either. The clause makes it clear that some reasons for Duke's failure to take energy excuse payment; and from the limited range of reasons that justify nonpayment it follows that other reasons are inadequate and that payment remains due.

The key to resolving the parties' dispute is in the beginning of what Benton asserted was a take-or-pay clause. It requires Duke to pay if it "fails to accept delivery of all of the Electrical

Output at the Point of Metering, whether due to Buyer's failure to obtain Transmission Service (if applicable) or for any reason other than . . . [a list]." This covers the sort of situation that prevailed after MISO changed its dispatch rules at the end of February 2013 and no longer deemed Benton a must-carry generator. As of March 2013, Benton was being told to stop 41% of the time because transmission was unavailable at the price Duke was willing to offer, if owners of the remaining local wind farms had made the same bid. With insufficient transmission capacity, someone had to stop delivering energy to NIPSCO's facilities no matter what price Duke offered.

But the contract provides what is to happen when the stoppage is "due to Buyer's failure to obtain Transmission Services." Duke is to pay for power not taken. Duke could build its own transmission lines or buy extra capacity from NIPSCO or some other firm.

If there is a market for transmission services, as there surely is in central Indiana where more and more wind power is becoming available, then there will be a supply of transmission lines. It is only a matter of time until more capacity is built, whether by Duke or someone else. Until that happens, the contract tells us that Duke must pay Benton.

The risk of inadequate transmission was contemplated by the contracting parties and allocated to Duke. By accepting this risk, Duke enabled Benton to finance its project. Duke wanted Benton's facilities to exist and called them into existence by promising to pay even if a shortfall of transmission services should lead to curtailment of deliveries. Potential buyers and sellers of electricity could and did foresee when negotiating this contract (and others like it) that electrical grids may be swamped by new sources of renewable power, which usually is located far from the centers of demand. They needed to allocate the risk of that development, which predictably would compel MISO to alter its rules for which sources could put power on the grid. Allocating the risk to Benton would have made it hard, perhaps impossible, to finance the project's construction, while leaving Duke and similar utilities no incentive to expand the regional grids as wind power became available. Allocating the risk to Duke facilitates both construction of renewable energy sources and better incentives to match the size of the transmission grid to the capacity for local generation. The court read the contract as allocating the risk to Duke, which means that Benton receives the compensation provided by the contract and Duke has the right incentives to build or buy extra transmission capacity. The lower court's judgment was reversed and the case remanded with instructions to determine the relief to which Benton is entitled.

D. United States Court of Appeals for the Ninth Circuit

1. MPS Merchant Servs., Inc. v. Federal Energy Regulatory Comm'n, Nos. 15-73803, 15-73818, 15-73905, 15-73912, 16-70004, 16-70524, 16-70525, 16-70868 (Sept. 8, 2016).

In these petitions consolidated for review, the Court considered whether the FERC arbitrarily and capriciously determined that various energy companies committed tariff violations in California during the summer of 2000. The Court concluded that FERC did not, and denied the petitions for review. This case is part of a long-standing series of decisions arising out of California's energy crisis in 2000 and 2001.

FERC in the 1990s commenced a program of deregulating and "unbundling" the wholesale electric power industry by restructuring and separating electrical generation, transmission, and distribution. California deregulated its investor-owned, regulated, vertically integrated utility market in 1996.

A part of the deregulation, California created two non-profit entities: The California Power Exchange Corporation ("CalPX") and the California Independent System Operator Corporation ("CAISO"). CalPX was a wholesale clearinghouse created primarily to operate two spot markets: (1) the "day-ahead" trading market, in which the market clearing price was derived from the sellers' and buyers' price and quantity determinations for the next day's energy transactions, and (2) the "day of" or "hour ahead" trading market, in which CalPX would determine, on an hourly basis, a single market clearing price which all suppliers would be paid. CAISO managed California's electricity transmission grid and was responsible for all real-time operations, including balancing electrical supply and demand. Both entities were subject to FERC jurisdiction, with CalPX operating pursuant to a FERC-approved tariff and wholesale rate schedule.

The CAISO tariff comprehensively regulated California's power markets. The tariff barred power marketers from buying electricity in the day-ahead market in order to resell that electricity in the real-time market. The tariff also incorporated a protocol—the Market Monitoring and Information Protocol ("MMIP")—which set forth rules for identifying and protecting against abuses of market power.

Unlike most energy markets, 80% of the California transactions during the relevant period were conducted in spot markets. After a summer 2000 spike in energy prices and a series of rolling blackouts, San Diego Gas & Electric company ("SDG&E") filed a complaint with FERC under § 206 of the Federal Power Act, requesting that FERC impose a price cap on sales into the CalPX and CAISO markets. FERC denied the request, but then commenced an investigatory proceeding into the justness and reasonableness of the market rates. FERC ultimately issued a number of orders, which have been the subject of prior petitions for review. This case returns to the Ninth Circuit after the court's decision in *CPUC*, in which the court directed FERC to determine whether certain sellers of electricity in California power markets violated the rules governing those markets in the summer of 2000, and whether these violations could be remedied under the agency's authority in § 309 of the FPA.

FERC therefore determined for the period from May 1, 2000 to October 1, 2000 (the "Summer Period"): (1) which market practices and behaviors constituted a violation of the then-current CAISO, CalPX, and individual sellers' tariffs and Commission orders; (2) whether any of the respondents engaged in those tariff violations; and (3) whether any such tariff violations affected the market clearing price. Months of hearings took place.

The Initial Decision found that certain energy companies had violated the CAISO tariff via several marketing strategies, which the ALJ dubbed "False Expert," "False Load Scheduling," and "Anomalous Bidding." A False Export occurred when a marketer purchased electricity from the CalPX or other sources internal to California, scheduled that electricity in advance for export, and subsequently scheduled that electricity in real-time for import. The twin transactions disguised the energy as sourced from outside, even though the electricity never left California. This strategy let sellers evade the CAISO real time price caps, which did not apply to imported power.

False Load Scheduling, or overscheduling, occurred when sellers in California's day-ahead market submitted exaggerated demand schedules to CAISO. The so-called uninstructed energy would then flow on California's transmission grid. CAISO would direct the energy to real-time shortages and, in exchange, pay the seller the real-time market's clearing price. The objective of the transaction was to earn the market-clearing price in the real-time market on the power which was purchased from the PX at the day-ahead price, thus earning the difference between the two prices. Both the False Load Scheduling and False Export strategies in simple terms did the same thing: they pulled energy out of the day-ahead market and they dumped it in the real-time market. The tactics relied on two Summer Period market realities: (1) real-time prices generally exceeded day-ahead prices, and (2) little real-time volume went unsold, as the demand for real-time energy is inelastic.

Anomalous Bidding was defined as bidding behavior that departs from normal competitive behavior in violation of the CAISO MMIP. Type I Anomalous Bidding included bids that vary in output in ways that are unrelated to cost. FERC found that the California Parties did not meet their prima facie burden of demonstrating that Type I Anomalous Bidding affected market clearing prices.

Type II Anomalous Bidding is defined as bids with prices above marginal cost in combination with some other tariff violation. Type III Anomalous Bidding, also known as Economic Withholding, is defined as bids used to effectuate supply withholding. Those bids occurred whenever the bid price was greater than market-clearing price and the seller's marginal cost was less than the market-clearing price. Some Type III anomalous bids were set so high above the market price that it was likely that they would not be accepted, thereby either diminishing the available supply to CAISO or increasing the market clearing price. FERC found 34,020 Summer Period transactions that amounted to tariff violations.

Over the course of the agency proceedings a number of entities settled with the California Parties and were dismissed from the case. The remaining entities in these petitions for review are: MPS Merchant Services, Inc. ("MPS"), formerly known as Aquila Merchant Service, Inc., a power marketer during the Summer Period; Illinova Corporation ("Illinova"), a power marketer during the Summer Period; Shell Energy North America, LP ("Shell"), a successor-in-interest to Coral Power, LLC, which purchased and resold energy and capacity during the Summer Period; APX, Inc. ("APX"), which served as a middleman between electricity buyers and sellers and California' energy markets during the Summer Period; and BP Energy Co. ("BP"), which sold electricity into the CAISO market through APX. In November 2014, FERC found that Shall, MPS, APX, and Illinova violated the CAISO tariff and that those violations impacted the market clearing price. At the California Parties' request, FERC in February 2016 again clarified its Summer Period determinations, clarifying that the remaining Respondents are liable to disgorge overcharges and excess payments they received for all sales during all hours of the Summer Period during which the market prices were inflated by tariff violations committed by any of the Respondents. These consolidated petitions followed.

The Ninth Circuit held that FERC reasonably interpreted the CAISO tariff and MMIP to prohibit the practices of False Export, False Load Scheduling and Types II and III Anomalous Bidding. The text of the tariff and MMIP provisions supports FERC's conclusions. At minimum, the Court defers to FERC's reasonable constructions of ambiguous tariff language.

The sellers' contrary position on overscheduling is self-refuting; renders superfluous much of the CAISO tariff; and thwarts California's efforts to supply electricity efficiently and reliably through day-ahead markets. FERC's legal interpretation of the MMIP follows agency precedent and there is no reason to disturb that interpretation. FERC reasonably interpreted the CAISO tariff and the MMIP according to the plain text of those documents to prohibit the practices of False Export, False Load Scheduling and Anomalous Bidding. FERC reasonably concluded that the tariff and MMIP sufficed to put sellers on notice that such practices were not permitted. FERC reasonably concluded that the sellers engaged during the Summer Period in the practices deemed tariff violations.

FERC's conclusion that MPS overscheduled and thereby violated the CAISO tariff was not arbitrary, capricious, or an abuse of discretion. MPS contends that it did not overschedule because the City of Azusa, California, submitted the controverted schedules. The fact that MPS laundered its overschedules through a municipal utility does not render arbitrary and capricious FERC's liability determination. Thus, substantial evidence supports FERC's finding that MPS engaged in False Load Scheduling in violation of the CAISO tariff.

Substantial evidence supports FERC's finding that MPS and Shell engaged in False Export. FERC determined that the California Parties established a prima facie case of False Export (1) by matching day-ahead transactions that exported electricity from California to real-time transactions that imported electricity to California, and (2) with evidence of "parking," that is, arrangements by which exporters sold energy outside the CAISO to entities who then nominally resold the energy to the exporter for a fee. FERC relies on evidence of at least five parking arrangements between MPS or Shell and utilities or municipalities. Furthermore, the California Parties' expert testimony provided substantial evidence for FERC's finding that the sellers' tariff violations increased market-clearing prices for electricity in the CalPX.

FERC reasonably determined that APX engaged in economic withholding and overscheduling, and therefore violated the CAISO tariff. FERC has long and repeatedly held that the language in Sections 205(b) and 206 does not contain any reference to intent. The Commission is to be concerned with anticompetitive effects, not motives. Therefore, consistent with controlling authority, FERC may apply such strict liability to determinations pursuant to Section 309.

E. <u>Utah Supreme Court</u>

1. Ellis-Hall Consultants v. Public Serv. Comm'n, 2016 UT 34.

This decision impacts the amount of deference the Utah courts will give an agency decision on review. Ellis-Hall is involved in the development of wind power projects. Its goal is to sell power to PacifiCorp, through its Rocky Mountain Power ("RMP") division, at avoided cost rates as a qualified facility ("QF") under the Public Utility Regulatory Policy Act ("PURPA"). Ellis-Hall received an indicative pricing proposal from RMP in 2012. RMP later rescinded that proposal and refused to proceed with power purchase agreement negotiations, arguing that the Utah PSC has since issued an order adopting a new pricing methodology. Ellis-Hall challenged that decision at the PSC, asserting a right to rely on the old indicative pricing in the negotiations.

In 2005, the PSC had adopted a "market proxy" methodology for determining the avoided cost for wind power projects. Later, RMP requested a change in methodology, which the PSC bifurcated into two phases. In the first phase, the PSC denied RMP's request for a stay for the 5 wind projects in the queue awaiting proposals. After receiving that order, RMP gave Ellis-Hall its indicative pricing proposal based on the market proxy methodology. Before Ellis-

Hall was able to negotiate a contract based on that pricing proposal, the PSC issued its second phase order, discontinuing the market proxy methodology and adopting the Proxy/Partial displacement differential revenue requirement method, which lowered RMP's avoided costs. RMP then sent Ellis-Hall a letter stating that the previously provided indicative pricing proposal was no longer valid and Ellis-Hall would have to resubmit for a new proposal under the new methodology. Instead of doing so, Ellis-Hall filed a complaint with the PSC.

The PSC, despite having ruled that the market proxy method was discontinued "going forward" and that only "future requests for indicative pricing" would be governed by the new methodology, ruled that RMP was required to update its pricing to reflect the new methodology and that Ellis-Hall was not entitled to the original indicative pricing proposal it received. Ellis-Hall appealed and the Utah Supreme Court reversed the PSC's decision.

The important point of the case was the court's decision regarding the standard of review. Even though in the past the court has given considerable weight to PSC interpretations and justified such deference on the basis of an inference of legislative intent to delegate to the responsible agency the discretionary power to interpret its regulations, the court reversed that precedent. It concluded that the appropriate standard is a non-deferential one that reviews the Commission's conclusions of law—its interpretations of its own prior orders and regulatory provisions—for correctness. The court specifically repudiated a standard of deference to administrative agencies like that which applies in federal court under *Chevron, U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984) and *Bowles v. Seminole Rock & Sand Co.*, 325 U.S. 410, 414 (1945).

Utility tariffs, PSC regulations, and PSC orders are law. The PSC, or any agency with respect to its own regulations and orders, cannot "revise" them based on a later interpretation. The court suggested that allowing the PSC, or any administrative agency, to interpret the laws that it writes is a violation of the separation of powers and unconstitutional. Citing *Marbury v. Madison*, the court stated that it is only the judiciary that has the province and duty to say what the law is.

2. Trans-Western Petroleum, Inc. v. United States Gypsum Company, 2016 UT 27.

This case involved a certified question from the United States Court of Appeals for the Tenth Circuit. The question was, "How should expectation damages be measured for the breach of an oil and gas lease?"

United States Gypsum Company ("US Gypsum"), a Delaware corporation that owns the oil and gas beneath about 1,720 acres in Sevier County, Utah, was contacted in August 2004 by Trans-Western Petroleum, Inc. ("TW"), a Colorado corporation involved in the buying and selling of oil and gas leases about the possibility of leasing a section of acreage in Sevier County. At the time, the oil and gas interest for that section of land had been leased to other parties, who had assigned their leasehold interest to an entity known as Wolverine. This preexisting lease, the "Wolverine lease," was due to expire on August 17, 2004. Therefore, US Gypsum agreed to lease that oil and gas interest to TW for a term of five years starting on August 17, 2004.

Within weeks of executing the TW lease, Wolverine informed TW and US Gypsum that Wolverine believed its lease was still in force and did not recognize TW's claimed interest in the property. US Gypsum then sent TW a letter purporting to rescind the lease on the basis of a mistake of fact. TW then filed suit for declaratory judgment and damages against Wolverine, US Gypsum and others in federal district court. The federal district court determined that the Wolverine lease had ended in August 2004. On appeal, this determination was upheld by the Court of Appeals for the Tenth Circuit. TW continued its suit against US Gypsum for breach of contract and breach of the covenant of quiet enjoyment.

The federal district court issued a final judgment that the TW lease was valid as of August 17, 2004, that US Gypsum had wrongfully rescinded the lease, and that the rescission constituted a breach of contract and a breach of the covenant of quiet enjoyment. The district court then awarded nominal damages of one dollar to TW for its claim for breach of contract. The parties appealed to the Tenth Circuit, who certified the question above to the Utah Supreme Court.

Expectation damages for the breach of an oil and gas lease are measured in much the same way as expectation damages for breach of any other contract. Such damages may include general (or direct) and consequential (or special) damages. In this case, the Utah Supreme Court said that general damages should be measured as the difference between the contract price of the lease and the market value of the lease at the time of the breach. Consequential damages should be measured not by the value of the promised performance alone but by the gains such performance could produce for collateral reasons, or the loss that is produced by the absence of such performance. In addition, trial courts, in their discretion, may allow the use of post-breach evidence to help establish and measure expectation damages.

3. USA Power, LLC v. PacifiCorp, 2016 UT 20.

This case concerns a dispute about proprietary plans to develop a power plant. USA Power, LLC ("USAP") engaged in extensive work to research and develop a power plant project in Mona, Utah—its Spring Creek "vision." USAP claimed that this vision is a trade secret, that PacifiCorp misappropriated it, and that PacifiCorp also breached a confidentiality agreement between the parties. USAP further claims that its water attorney, Jody L. Williams, and her law firm, Holme Roberts & Owen, LLC breached their fiduciary duties by working for PacifiCorp to acquire water rights on a competing power plant proposal.

To advance its proposed power plant project, USAP made several public disclosures to regulatory bodies, but some information about the proposed plant was maintained as confidential. PacifiCorp had identified a quickly approaching need for energy and approached USAP and entered into negotiations to purchase USAP's assets. Eventually PacifiCorp terminated the negotiations over the sale and decided to issue a Request for Proposal ("RFP") to obtain bids for power sufficient to cover its needs. USAP submitted its proposed power plant in response to the RFP. PacifiCorp submitted its own competing proposal in the RFP to build a power plant in Mona, Utah—its Currant Creek project. PacifiCorp's Currant Creek project was very similar to USAP's Spring Creek proposal. PacifiCorp also retained Ms. Williams, USAP's former attorney, to help it obtain water rights for its Currant Creek project. PacifiCorp selected its own Currant Creek project over USAP's proposal.

USAP brought suit against Ms. Williams asserting malpractice claims based on an alleged breach of her fiduciary duties of confidentiality and loyalty. USAP also sued PacifiCorp asserting that PacifiCorp had misappropriated USAP's trade secrets—its vision for a plant in Mona, Utah, and various components of this vision, which were themselves trade secrets.

The trial court first granted summary judgment to the Defendants. The Utah Supreme Court reversed and clarified that a compilation of publicly available information could, in some circumstances, constitute a trade secret. A five-week jury trial was then held. The jury returned a special verdict against PacifiCorp and Ms. Williams. The trial court reduced the unjust enrichment award against PacifiCorp, granted Ms. Williams' JNOV motion for lack of evidence related to causation, and determined that USAP was entitled to attorneys' fees. The court also denied USAP's request for exemplary damages and prejudgment interest. The parties appealed all adverse rulings. The Utah Supreme Court upheld the trial court on all claims.

In the case, the Utah Supreme Court also concluded that the law of the case doctrine does not preclude a trial court from reexamining arguments made in a summary judgment motion if those arguments have been cast in a different light, such as when a motion is brought after the evidence has been adduced at trial. Under the law of the case doctrine, issues resolved by the appellate court on appeal bind the trial court on remand, and generally bind the appellate court should the case return on appeal after the remand. However, while the appellate court's pronouncements on legal issues are binding as the law of the case, the appellate court's decisions on factual issues are not necessarily. The factual issues decided by an appellate court may be revisited by a lower court when they are presented to the lower court in a "different light," which is satisfied when the factual and legal posture of the case has changed since the initial decision was rendered.

F. <u>Utah Court of Appeals</u>

1. *Jesse H. Dansie Family Trust v. Public Serv. Comm'n, 2016 UT App 116.*

This case involves the Utah Public Service Commission's ("PSC") abrogation of a contract. In 1977, Jesse H. Dansie leased the use of a well on his property to Gerald Bagley, developer of Hi-Country Estates ("Well Lease"). After additional amendments to the Well Lease, Dansie received some residential water hook-ups and the right to receive up to 12 million gallons of water per year from the combined water system at no cost for culinary and yard irrigation on the Dansie property. After a period of time, the Hi-Country Estates Homeowners Association ("HOA") requested reinstatement of its water system's Certificate of Public Convenience and Necessity ("CPCN"). The PSC granted the HOA request, bringing the HOA back into the jurisdiction of the PSC. A year later, the HOA filed for a general rate increase, suggesting the Well Lease customers pay a rate of $3.85 per 1,000 gallons.

After a hearing, the PSC found the Well Lease to be unreasonable, unjust and not in the public interest. It ruled that the Well Lease was void and unenforceable as against the public interest. The Jesse H. Dansie Family Trust claimed that the PSC exceeded its jurisdiction when it concluded the Well Lease is void and unenforceable. The Utah Court of Appeals disagreed and affirmed the PSC's decision.

The Dansie Court noted that the legislature gave the PSC broad powers, which specifically included rate making. If, in performing that function, the PSC finds after a hearing that contracts affecting rates are unjust; unreasonable; discriminatory; preferential; or otherwise in violation of any laws, the PSC shall determine the just, reasonable, or sufficient rates or contracts to be thereafter observed. In addition, in the fixing of rates for public utility service, the PSC is not limited or controlled by the provisions of antecedent contracts, but is at liberty to disregard such contracts altogether if they come in conflict with what the PSC finds to be reasonable under the conditions existing at the time of making the investigation. Therefore, the PSC did not exceed its jurisdiction in finding the Well Lease void and unenforceable.

II. ADMINISTRATIVE INITIATIVES AND ACTIONS

A. Utah Public Service Commission Proceedings

1. In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program, Docket No. 14-035-114.

On November 10, 2015, the Public Service Commission ("PSC" or "Commission") issued an order adopting a general framework for assessing the costs and benefits of net metering. The order required PacifiCorp to file cost of service ("COS") studies, which would allow the Commission to evaluate the costs and benefits of net metering. PacifiCorp filed a request on November 9, 2016, asking the PSC to (i) find, based on the COS Studies submitted with the request, that the costs of the net metering program exceed the benefits under the existing structure; (ii) find that the unique characteristics of net metering customers warrant segregating them into a distinct class; (iii) find the current rate structure for net metering customers is unjust and unreasonable because it does not reflect the costs to serve these customers and unfairly shifts costs from net metering customers to other customers or to PacifiCorp; (iv) approve new rates and schedules for net metering customers; and (v) allow PacifiCorp to charge its proposed interconnection application fee for net metering customers. Ten parties filed dispositive motions moving to dismiss PacifiCorp's request predicated on the following: (i) the PSC may not, as a matter of law, set rates outside a general rate case; (ii) the request fails to comply with the requirements of the 2015 order; (iii) the request asks the Commission to engage in single-item and/or retroactive ratemaking; (iv) PacifiCorp has not shown cause for a new interconnection fee; and (v) the request is substantively deficient.

The PSC determined that no moving party demonstrated that PacifiCorp's request failed as a matter of law. A technical conference is scheduled for May 18 at 1:30 p.m. Testimony has been scheduled and a hearing is set for the week of August 14 through August 18, beginning each day at 9:00 a.m.

B. Federal Energy Regulatory Commission Proceedings

1. 157 FERC ¶ 61,212, Docket No. RM17-8-000, Notice of Proposed Rulemaking.

On December 15, 2016, FERC opened a rulemaking to revise its regulations and the *pro forma* Large Generator Interconnection Procedures ("LGIP") and the *pro forma* Large Generator Interconnection Agreement ("LGIA").

The LGIA and LGIP were last seriously evaluated in Order No. 2003. Pursuant to a petition for rulemaking filed in June 2015, FERC held a technical conference and accepted comments to explore issues raised related to the interconnection rules and procedures. As a result, the Commission opened this rulemaking. The Commission proposed fourteen reforms that focus on improving aspects of the LGIA and LGIP, which fall into three broad categories intended to: (1) improve certainty in the interconnection process; (2) improve transparency by providing more information to interconnection customers; and (3) enhance interconnection processes.

2. 157 FERC ¶ 61,124, Docket No. RM17-4-000, Notice of Inquiry.

In this notice of inquiry, FERC seeks comment on whether, and, if so, how the Commission should revise its policy for establishing the length of original and new licenses it issues for hydroelectric projects at non-federal dams.

The length of a new license has recently been contested in several relicensing proceedings. The arguments raised in these cases include that the Commission, when establishing the license term, should have considered, or given more weight to: capacity-related investments or environmental enhancements made by the licensee during the current license and before issuance of the new license; total cost of the relicensing process; losses in generation value related to environmental measures; the license terms of projects that the licensee states are similarly situated to its project; and the license term provided for in settlement agreements. In each circumstance, FERC declined to deviate from its current policy to extend the length of the license. It now seeks comment on whether its policies should be revised.

3. 157 FERC ¶ 61,122, Docket No. RM16-6-000, Notice of Proposed Rulemaking.

FERC proposes to revise its regulations to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection. The Commission also proposes to establish certain operating requirements, including maximum droop and deadband parameters in the *pro forma* LGIA and *pro forma* Small Generator Interconnection agreement ("SGIA"). These latter changes would not be applicable to generating facilities regulated by the Nuclear Regulatory Commission. This requires changes to both the LGIA and the SGIA.

4. 157 FERC ¶ 61,047, Docket No. RM17-1-000, Advanced Notice of Proposed Rulemaking.

FERC is considering modifications to its policies for evaluating oil pipeline index rate changes and to the data reporting requirements reflected in page 700 of Form No. 6. The Commission's index ratemaking methodology has become the predominant mechanism for adjusting oil pipeline rates under the Interstate Commerce Act ("ICA"). Ensuring that the index rate increases do not cause pipeline revenues to unreasonably depart from oil pipeline costs, and that both the Commission and oil pipeline shippers have sufficient information to assess the relationship between oil pipeline rates and costs, is essential to FERC's implementation of its statutory obligations under the ICA.

A petition for rulemaking was filed in July 2015, seeking additional cost information. The Commission held a technical conference discussing this proposal and the asserted need for greater insight into oil pipelines' costs and revenues to enable shippers to challenge oil pipeline rates that may be unjust and unreasonable.

Through the Commission's ongoing monitoring of how the index affects pipeline rates, the Commission has observed that some pipelines continue to obtain additional index rate increases despite reporting revenues that significantly exceed costs. In addition, the Commission feels that its standards for evaluating shipper objections to index filings could be strengthened and clarified. Accordingly, in this rulemaking, the Commission proposes reforms to its review of oil pipeline index rate filings and the reporting requirements for Form No. 6, page 700 to better fulfill its statutory obligations under the ICA. The Commission is considering a new policy that would deny proposed index increases if (a) a pipeline's Form No. 6, page 700 revenues exceed the page 700 total cost-of-service by 15% for both of the prior two years or (b) the proposed index increases exceed by 5% the annual cost changes reported on the pipeline's most recently filed page 700. The Commission is also considering applying these new reforms to costs more closely associated with the proposed indexed rate than the total company-wide costs and revenues presently reported by oil pipelines on page 700.

5. 156 FERC ¶ 61,214, Docket No. RM15-21-000, Notice of Inquiry.

On September 22, 2016, FERC issued a Notice of Inquiry to explore whether, and if so, how, the Commission should revise its current approach to identifying and assessing market power in the context of transactions under section 203 of the Federal Power Act and applications for market based rate authority for wholesale sales of electric energy, capacity and ancillary services under section 205 of the Federal Power Act. The Commission also sought comment related to its scope of review under section 203 of the Federal Power Act, including revisions to some blanket authorizations.

6. 156 FERC ¶ 61,062, Docket No. RM16-8-000, Order No. 828, Final Rule.

Last year, FERC proposed revisions to its small generator interconnection policy to reflect the need for those generators to "ride through" and stay connected during abnormal frequency and voltage events similar to large generators. As a result of this Final Rule, issued in July 2016, small generating facilities are required to not disconnect automatically or instantaneously from the system or equipment of the transmission provider and any affected systems for an under-frequency or over-frequency condition, or an under-voltage or over-voltage condition. In addition, the transmission provider must coordinate the small generating facility's protective equipment setting with any automatic load shedding program.

7. 156 FERC ¶ 61,055, Docket No. RM05-5-025, Notice of Proposed Rulemaking.

FERC issued this notice of proposed rulemaking in July 2016, proposing to amend its regulations to incorporate by reference the latest version of certain Standards for Business Practices and Communication Protocols for Public Utilities (V. 003.1) adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). There are also several NAESB standards FERC did not propose incorporating by reference. The Commission also proposes to list informationally, as guidance, NAESB's updated Smart Grid Business Practice Standards in Standard WEQ-019.

8. 156 FERC ¶ 61,047, Docket No. RM16-3-000, Withdrawal of Notice of Proposed Rulemaking and Termination of Rulemaking Proceeding.

On December 17, 2015, the Commission issued a Notice of Proposed Rulemaking, proposing to amend its regulations to clarify the scope of ownership information that sellers seeking to obtain or retain market-based rate authority must provide. The Commission has since developed a new proposal, as reflected in a concurrently issued NOPR to streamline and consolidate the collection of market-based rate information with new information proposed to be collected for analytics and surveillance purposes. Therefore, the Commission withdrew this NOPR and terminated the rulemaking proceeding.

9. 156 FERC ¶ 61,046, Docket No. RM15-23-000, Withdrawal of Notice of Proposed Rulemaking and Termination of Rulemaking Proceeding.

On September 17, 2015, the Commission issued a Notice of Proposed rulemaking wherein it proposed to require each regional transmission organization and independent system operator to electronically deliver to the Commission, on an ongoing basis, data required from its market participants that would: (i) identify the market participants by means of a common alpha-numeric identifier; (ii) list their "Connected Entities," which included entities that have certain ownership, employment, debt, or contractual relationships with the market participants; and (iii) describe in brief the nature of the relationship of each Connected Entity. The Commission proposed to collect such information to assist it with screening and investigating market manipulation. After receiving many negative comments, the Commission developed a new, narrower proposal and therefore, withdrew this original proposal on July 21, 2016.

10. 156 FERC ¶ 61,045, Docket No. RM16-17-000, Notice of Proposed Rulemaking.

This rulemaking replaces that one withdrawn in Docket No. RM15-23-000. Instead, the Commission proposes to revise its regulations to collect certain data for analytics and surveillance purposes from market-based rate ("MBR") sellers and entities trading virtual products or holding financial transmission rights and to change certain aspects of the substance and format of information submitted for MBR purposes. The proposed revisions include new requirements to report certain information about legal and financial connections to other entities to assist the commission in its analytics and surveillance efforts. This proposal includes substantial revisions from the previous one, including (i) a different set of filers; (ii) a reworked and substantially narrowed definition of Connected Entity; and (iii) a different submission process. In addition, with respect to the MBR program, the proposals include: (i) adopting certain changes to reduce and clarify the scope of ownership information that MBR sellers must provide; (ii) reducing the information required in asset appendices; and (iii) collecting currently-required MBR information and certain new information in a consolidated and streamlined manner.

11. 155 FERC ¶ 61,277, Docket No. RM16-1-000; Order No. 827, Final Rule.

FERC issued this Final Rule on June 16, 2016. It eliminates the exemptions for wind generators from the requirement to provide reactive power by revising the *pro forma* LGIA, Appendix G to the *pro forma* LGIA, and the *pro forma* SGIA. As a result, all newly interconnecting non-synchronous generators will be required to provide reactive power at the high-side of the generator substation as a condition of interconnection.

12. 155 FERC ¶ 61,188, Docket No. RM14-14-001; Order No. 816-A, Order on Rehearing and Clarification.

On May 19, 2016, FERC issued this order denying requests for rehearing and granting, in part, clarification of its determinations in Order No. 816, which amended its regulations that govern MBR authorizations for wholesale sales of electric energy, capacity, and ancillary services pursuant to the Federal Power Act. In most respects, FERC affirmed its determinations made in Order No. 816. FERC denied rehearing regarding the requirement to include the expiration date of the contract when a seller claims that its capacity is fully committed. To the extent that the expiration date is not known, a subsequent filing to report the contract expiration date will be treated as an informational filing rather than as an amendment to a pending application.

With respect to the requirement for applicants in regional transmission organizations ("RTO") or independent system operators ("ISO") to report all long-term firm energy and capacity purchases from generation capacity located within the RTO/ISO market if the generation is designated as a resource with capacity obligations, this does not apply if the generation is from a qualified facility ("QF"). Also, a MBR seller must list all its long-term firm power purchases in its asset appendix, even if it does not have MBR authority in its home balancing authority area ("BAA").

Additional clarifications include, but are not limited to, (i) long-term firm transmission reservations are those longer than 28 days; (ii) a hydropower licensee that otherwise sells power only at MBR will not be subject to the full requirements of the Uniform System of Accounts as a consequence of filing a cost-based reactive power tariff and may satisfy the requirements of Part 101 by complying with General Instruction 16 of the Uniform System of Accounts; and (iii) sellers are not required to include behind-the-meter generation in the 100 MW change in status threshold, the 500 MW Category 1 seller status threshold, or the asset appendices and indicative screens.

III. UTAH LEGISLATION

A. Renewable Energy Amendments, H.B. 297, 2017 Leg., 62nd. Sess.

This bill amended Utah Code Ann. § 54-17-801 to change the definition of "Renewable energy facility," allowing baseload renewable resources from outside the state of Utah to qualify. This primarily allows geothermal resources from outside Utah to qualify as renewable energy facilities under Utah law.

B. Oil & Gas Amendments, S.B. 191, 2017 Leg., 62nd. Sess.

This bill modifies the duties of the Board of Oil, Gas, and Mining, amending Utah Code Ann. §§ 40-6-2, -6, -6.5. It modifies the definitions of "Consenting Owner" and "Nonconsenting Owner" and allows the Board to make an order establishing a drilling unit or a pooling order retroactive under certain circumstances.

C. Energy Development Amendments, S.B. 273, 2017 Leg., 62nd. Sess.

This bill enacts the Commercial Property Assessed Clean Energy Act or C-PACE Act at Utah Code Ann. § 11-42a-101, *et seq*. It creates a C-PACE district, requires the Office of Energy Development ("OED") to administer and direct the actions of a C-PACE district, allows OED to delegate OED's authority over the C-PACE district to a third party, and provides other terms related to energy assessments.

IV. MISCELLANEOUS

A. Dominion Resources Acquisition of Questar Corporation

On September 16, 2016, Dominion Resources, Inc. and Questar Corporation announced that they had completed their proposed merger, forming one of the nation's largest combined electric and natural gas energy companies. Dominion considered Questar's "hub of the Rockies" system a principal gateway for gas supply to Western states, especially as Western states are expected to rely on lower-carbon natural gas-fired power generation. Questar, now Dominion Questar, will operate as a first-tier, wholly owned subsidiary of Dominion. Questar Gas's headquarters will remain in Salt Lake City, along with a newly formed Western Regional operating headquarters. Ron Jibson, chairman, president and chief executive officer of Questar, was elected to Dominion's board of directors. The Utah Public Service Commission approved the merger pursuant to a settlement stipulation from the bench after hearing on August 22, 2016.

B. Energy Imbalance Market

The Energy Imbalance Market ("EIM") provides automatic dispatch of least-cost imbalance energy to serve real-time customer demand across a wide geographic area. It has enhanced grid reliability, generated cost savings for its participants, and improved the integration of renewable energy. It was first developed in the California Independent System Operator ("CAISO"). PacifiCorp joined in 2014 and NV Energy, PacifiCorp's Berkshire Hathaway affiliate, joined in December 2015. Puget Sound Energy and Arizona Public Services joined in October 2016. Portland General Electric is scheduled to join in 2017, Idaho Power is scheduled to join in 2018, Seattle City Light is scheduled to join in 2019, and the Salt River Project is scheduled to join in 2020.

C. PacifiCorp to Join CAISO in a Regional ISO

CAISO was working to launch a regional energy market to advance the state's ambitious clean energy goals and to reduce the cost of energy in the western states. PacifiCorp began studying and evaluating the possibility of joining with the CAISO to form a regional ISO in 2015. Because the board of CAISO is appointed by the Governor of California, California legislation is necessary to develop a new governance design that will make it attractive for utilities throughout the west to participate. Throughout 2016, CAISO and PacifiCorp conducted stakeholder processes and issued straw proposals for development of policies such as transmission access charges, greenhouse gas compliance, resource adequacy, and metering. However, without the necessary change in governance, those processes have been put on hold until a governance structure can be proposed and agreed upon.

D. Clean Power Plan

On April 28, 2017, a 10-judge panel of the U.S. Court of Appeals for the District of Columbia Circuit granted the request to put the litigation involving the regulations known as the Clean Power Plan in abeyance for at least 60 days while the administration plans its next steps. The court also asked the administration and other parties to file briefs on whether the case should be sent back to the Environmental Protection Agency ("EPA"). The Supreme Court last year put the regulations on hold pending the outcome of the case in the DC Circuit.

E. MATS

On April 27, 2017, the U.S. Court of Appeals for the District of Columbia Circuit granted an EPA request to halt the upcoming oral arguments to consider a supplemental cost analysis associated with the Mercury and Air Toxics Standards to allow an agency review. EPA's supplemental finding determined that MATS was appropriate and necessary considering the cost of compliance. The analysis was required following a June 2015 decision from the U.S. Supreme Court that found the EPA had improperly considered the cost of complying with MATS. The nation's power plants have almost entirely come into compliance with MATS, save for one facility in Oklahoma that was granted a last-ditch extension on April 14. Stakeholders were confused as to why the Trump administration would seek to review a rule that has already been implemented.

F. FERC Workshop AD17-11

FERC held a two day workshop May 1-2, 2017 to examine how power markets can select resources that states want while preserving the benefits of regional markets and economic resource selection. It included PJM, ISO-NE, and NYISO. Panels discussed roles of competitive wholesale markets and state policies in the East in shaping the composition of resources needed to cost effectively meet future reliability and operational needs. This comes in the wake of a number of state initiatives that were overturned by the U.S. Supreme Court in the last few years.