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FEDERAL — MINING

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— REPORTER —

USING LIMESTONE AS A SOIL ADDITIVE DOES NOT MAKE IT AN UNCOMMON VARIETY

The Interior Board of Land Appeals' (IBLA or Board) decision in *United States v. Pitkin Iron Corp.*, 170 IBLA 352, GFS(MIN) 30(2006), addresses the question of "first impression" of whether use of limestone as a soil additive establishes the material as an uncommon variety. IBLA overturned the administrative judge's determination that the Bureau of Land Management (BLM) had failed to provide a prima facie case that the limestone at issue was a common variety and proceeded to address the merits of the claim contest. The limestone was used as a soil additive by a nearby mine to neutralize acidic soil in connection with its reclamation activities. Determining that such a use does not result in a conclusion that the material is an uncommon variety, the IBLA also provided a detailed outline of the status of the law of common varieties and announced several new applications of that law.

The Common Varieties Act, 30 U.S.C. § 611, removed deposits of common varieties of stone and other material from location under the Mining Law, providing that common varieties do not include deposits that are valuable because the deposit has "some property giving it distinct and special value." The legislative history of the statute specifically addressed limestone, noting that "limestone suitable for use in the production of cement, metallurgical or chemical-grade limestone . . . and the like" were excluded from the definition of common varieties. 170 IBLA at 356. This observation was codified in the agency's regulations. 43 C.F.R. § 3711.1(b) (2002). The 2003 amendment to the rule eliminated the catchall "and the like," specifying only that "Limestone of chemical or metallurgical grade, or that is suitable for making cement, is subject to location under the mining laws." 43 C.F.R. § 3830.12(d). The Department defined what constitutes metallurgical or chemical grade limestone in a 1969 Solicitor's Opinion, *United States v. Pfizer & Co.*, 76 I.D. 331 (1969), in which the Solicitor concluded that such limestone averages 95% or more total calcium and magnesium carbonates.

In 1969, the Ninth Circuit in *McClarty v. Secretary of the Interior*, 408 F.2d 907, 908 (9th Cir. 1969), adopted a five-part test for determining whether a deposit is an uncommon variety:

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GREGORY R. DANIELSON
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— REPORTERS —

U.S. SUPREME COURT HOLDS SIX-YEAR STATUTE OF LIMITATIONS DOES NOT APPLY TO MMS ADMINISTRATIVE ORDERS

In *BP America Production Co. v. Burton*, 127 S. Ct. 638 (2006), the U.S. Supreme Court affirmed the D.C. Circuit and resolved the conflict between the D.C. Circuit's decision and the Tenth Circuit's contrary holding in *Oxy USA, Inc. v. Babbitt*, 268 F.3d 1001 (10th Cir. 2001). The Supreme Court held that 28 U.S.C. § 2415(a)'s six-year statute of limitations on actions for money damages by the U.S. government did not apply to administrative orders of the Minerals Management Service (MMS) that assessed BP for royalty underpayments on oil and gas leases it held on government lands for the years preceding 1996.

Under 28 U.S.C. § 2415(a),

every action for money damages brought by the United States . . . which is founded upon any contract express or implied in law or fact, shall be barred unless the complaint is filed within six years after the right of action accrues or within one year after final decisions have been rendered in applicable administrative proceedings required by contract or by law, whichever is later.

The six-year statute of limitations applied to actions on any government contracts until 1996 when Congress enacted the Federal Oil and Gas Royalty Simplification and Fairness Act of 1996 (FOGRSFA), which specifically adopted a prospective seven-year statute of limitations for any judicial proceeding or administrative demand for payment of royalties arising under a federal oil and gas lease. 30 U.S.C. § 1724(6). Due to the prospective nature of FOGRSFA's seven-year statute of limitations, the six-year statute of limitations set forth in § 2415 continued to govern payment of royalties for pre-1996 oil and gas production.

Relying on the plain language of § 2415, the intent of Congress, and the passage of FOGRSFA, the Supreme Court determined that the MMS had properly assessed BP for pre-1996 royalty underpayments. First, the Court determined that the terms "action," "complaint," and "right of action accrues" are typically used in connection with judicial proceedings and do not ordinarily

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1) there must be a comparison of the mineral deposit in question with other deposits of such minerals generally; 2) the mineral deposit in question must have a unique property; 3) the unique property must give the deposit a distinct and special value; 4) if the special value is for uses to which ordinary varieties of the mineral are put, the deposit must have some distinct and special value for such use; 5) the distinct and special value must be reflected by the higher price which the material commands in the market place.

The Board in *Pitkin* noted that it has followed the *McClarty* test for more than 30 years and that the test was codified in the 2003 amendment to the common variety regulations, 43 C.F.R. § 3830.12(b). 170 IBLA at 359-60.

The decision in *Pitkin* appears to resolve what the Board characterized as an ambiguity in its prior precedent regarding whether limestone that is not cement, metallurgical, or chemical grade can ever be characterized as an uncommon variety subject to location. *See* 170 IBLA at 359. The material at issue in the case was concededly not of that grade, and the Board analyzed the issue under the *McClarty* standard, announcing that:

The rule is now this: if metallurgical or chemical grade limestone, or use in cement, cannot be shown, a claimant must preponderate with proof that its limestone meets the test of *McClarty*.

170 IBLA 395.

In arguing that its limestone satisfied the *McClarty* test, *Pitkin* relied on the fact that the material had been used as a soil amendment to neutralize acidic soil at mine reclamation sites. In a lengthy discussion IBLA rejected the contention, concluding that such use was not uncommon and that there was an ample supply of limestone in the area suitable for that use. *Id.* at 386-87. The Board noted that, because the use was a common one, *Pitkin* could prevail only by establishing that its deposit had a unique property giving it a distinct and special value in that use. *Pitkin* failed in making that showing, because its limestone was no more suitable as a soil additive than other similar limestone widely available in the area. *Id.* at 395-98.

The Board rejected *Pitkin's* attempts to argue that its limestone must be considered uncommon because, as a soil additive, it commanded a slightly higher price in the market place than did limestone sold for other uses. The Board concluded that while a higher price might be indicative of the unique nature of the deposit, a claimant cannot rely on price alone to establish the uniqueness of material. *Id.* at 387-88. The *McClarty* test requires establishing both that the deposit has a "unique property and [that] the unique property . . . impart[s] to the deposit a distinct and special value." *Id.* at 388.

IBLA also rejected *Pitkin's* argument that limestone used as a soil additive should be considered, *per se*, an uncommon variety because the material results in a chemical change in soil, as opposed to a mere physical amendment. The argument was based on a line of cases beginning with *United States v. Bunkowski*, 5 IBLA 102,

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79 I.D. 43, GFS(MIN) 13, GFS(MISC) 36(1972), in which the Board had speculated that certain materials used as soil additives might be considered to be uncommon varieties if they result in chemical, rather than merely physical, changes to the soil. IBLA

refused to extend this rationale to limestone, concluding that to do so would not be consistent with the Common Varieties Act, that the prior observations were *dicta*, and that such a rule was inconsistent with the test set forth in *McClarty* and the agency's regulations.

SURFACE OCCUPANCY RULES STILL A CHALLENGE FOR BLM

In a 2002 decision, the Interior Board of Land Appeals (IBLA) explained to the Bureau of Land Management (BLM) that the surface occupancy rules do not prohibit occupancy in connection with casual uses or seasonal activities. *Thomas E. Swenson*, 156 IBLA 299, GFS(MIN) 12(2002), reported in Vol. XIV, No. 2 (2002) of this *Newsletter*. IBLA reiterated this conclusion in *Dan Solecki*, 162 IBLA 178, GFS(MIN) 26(2004), ruling that the appropriate question is not whether the mining activities are seasonal or constitute casual use, but rather whether the occupancy satisfies the standards set forth in 43 C.F.R. §§ 3715.2, 3715.2-1. In *Cynthia Balse*, 170 IBLA 269, GFS(MIN) 27(2006), IBLA once again took BLM to task over its interpretation of the surface occupancy rules. As it did in *Swenson* and *Solecki*, IBLA set aside a cessation order that was based on the reasoning that occupancy in connection with "causal use is not 'in compliance' with the 3715 regulations" and that occupancy cannot be justified by seasonal uses. *Id.* at 271-72, 278. The Board noted, once again, that the subpart 3715 regulations expressly contemplate that occupancy of a mining claim may be based on activities that would be deemed casual use under the subpart 3809 regulations. *Id.* at 277-78. Similarly, the Board concluded that the surface occupancy regulations provide that an occupancy may be justified by a seasonal, but recurring, work program. *Id.* at 278-79. Accordingly, IBLA remanded the matter to BLM for action consistent with the standards set out in *Swenson* and *Solecki*.

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apply to administrative proceedings. The Court noted that under § 2415(a) Congress expressly differentiated between the two notions when it provided for a one-year statute of limitations on final decisions from administrative proceedings. Second, the Court rejected BP's argument that the MMS administrative order serves as a "complaint" because it specifically lacks the formalities of a complaint. While a complaint commences a proceeding that may result in the imposition of a legal obligation, an MMS payment letter in and of itself imposes a legal obligation to make payment to the government with substantial penalties for a lessee's failure to comply. Finally, the Supreme Court acknowledged BP's policy argument that the Court's interpretation of § 2415 permits the MMS to issue payment orders that may predate the seven-year requirement for retention of records under FOGRSFA, but stated

that such inconsistencies would also exist if the six-year statute were applied to administrative actions. As an example, the Court noted that payment orders relating to leases of Indian land, which leases are exempt from the requirements of FOGRSFA, would be subject to a shorter statute of limitations than leases of other public domain lands. In light of the trust responsibility in the administration of Indian lands, the Court stated that it is unlikely that Congress intended to impose a shorter statute of limitations for payment orders affecting Indian lands.

IBLA FINDS THAT BLM FAILED TO COMPLY WITH NEPA WHEN DENYING PROTEST OF LEASE SALE

The Utah State Office of the Bureau of Land Management (BLM) denied The Center for Native Ecosystems' (CNE) protest of the sale of 15 parcels in a federal oil and gas lease sale. In *Center for Native Ecosystems*, 170 IBLA 331, GFS(O&G) 17(2006), the Interior Board of Land Appeals (IBLA) reversed the BLM decision and remanded the matter for further consideration and held that the BLM failed to comply with the National Environmental Policy Act of 1969 (NEPA) when it denied the CNE's protest of the sale of federal oil and gas leases.

Certain parcels of land in the sale (Subject Area) contained critical habitat for white-tailed prairie dog colonies which serve as potential reintroduction sites of the black-footed ferret. Prior to the lease sale, the BLM did not prepare a new Resource Management Plan/Environmental Impact Statement (RMP/EIS), or Environmental Assessment (EA) to address the impacts of oil and gas leasing on the ferret population or habitat. Instead, the BLM prepared a Determination of NEPA Adequacy (DNA) in which it determined that leases on the Subject Area conformed to existing land use plans and the existing EISs and EAs were adequate to support the lease sale. The existing RMPs and EISs for the Subject Area, however, did not directly address the impacts of oil and gas leasing on prairie dog or ferret habitat. The Diamond Mountain RMP/EIS specifically determined that further NEPA review would be necessary for ferret reintroduction and habitat. In addition, the U.S. Fish and Wildlife Service (FWS) objected to leasing in the Subject Area. The BLM determined, however, that there would be no significant impacts of leasing other than those already analyzed in the existing NEPA documents and subsequently included the Subject Area in the lease sale. Each lease contained a "special status species stipulation" (Special Stipulation) providing that the leased area may contain plants, animals, or animal habitats that are endangered or threatened or hold a special status under federal or state regulations. 170 IBLA at 333. In the Special Stipulation, the BLM retained the right to provide recommendations to the lessee and to modify development of the lease; however, the Special Stipulation did not allow the BLM to revoke the lease if critical prairie dog or ferret habitat was not properly protected.

EDITOR'S NOTE ON UNPUBLISHED OPINIONS: This *Newsletter* sometimes contains reports on unpublished court opinions that we think may be of interest to our readers. Readers are cautioned that many jurisdictions prohibit the citation of unpublished opinions. Readers are advised to consult the rules of all pertinent jurisdictions regarding this matter.

Relying on *Pennaco Energy, Inc. v. U.S. Department of the Interior*, 377 F.3d 1147, 1162 (10th Cir. 2004), and its own review of the existing RMPs and EISs, the IBLA held that the BLM's preparation of a DNA was not sufficient under NEPA to supplement previous EAs, EISs, or RMPs because the prior documents did not directly address the impacts of oil and gas leasing on prairie dog or ferret habitat. Further, the IBLA held that when the BLM disagrees with a sister agency it is incumbent upon the BLM to address that agency's concern. In this case, the BLM's finding of no significant impact failed to address the FWS's concerns about the impact of oil and gas leases covering ferret re-introduction sites. The IBLA also held that it was not CNE's responsibility to provide the BLM with new ferret population and habitat information. It was the BLM's responsibility to conduct a supplemental NEPA review of the ferret population and habitat prior to making the Subject Area available for leasing. Finally, the IBLA determined that the Special Stipulation did not provide appropriate mitigation measures that would ensure protection of the prairie dog or ferret population and habitat from the impacts of oil and gas leasing and that the Special Stipulation cannot be proffered to avoid BLM's NEPA obligations.

CONGRESS /
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ROBERT C. MATHES
— REPORTER —

CONGRESS PASSES NEW WILDERNESS PROTECTION BILLS

In its waning days, the 109th Congress passed several wilderness and protection bills. On October 17, 2006, Congress passed the Northern California Coastal Wild Heritage Wilderness Act designating certain National Forest System lands in the Mendocino and Six Rivers National Forests and certain Bureau of Land Management (BLM) lands in Humboldt, Lake, Mendocino, and Napa Counties in the State of California as wilderness areas. Pub. L. No. 109-362, 120 Stat. 2064 (2006). The Act created approximately 264,000 acres of wilderness areas in Northern California, released the remaining areas of the King Range Chemise Mountain, Red Mountain, Cedar Roughs, and Rocky Creek wilderness study areas from further consideration under section 603(c) of the Federal Land Policy and Management Act of 1976, and created a potential wilderness area for the Elkhorn Ridge lands administered by the BLM. The Act also designated portions of the Black Butte River and Cold Creek as wild rivers under the Wild and Scenic Rivers Act, 16 U.S.C. § 1274(a).

Congress withdrew, subject to valid existing rights, from entry, appropriation, and disposal, including location, entry, and patent under the mining laws, the Valle Vidal unit of the Carson National Forest in New Mexico. Pub. L. No. 109-385, 120 Stat. 2681 (2006). The Valle Vidal unit consists of 101,794 acres of national forest lands.

Congress also withdrew from all forms of location, entry, and patent under the mining laws and disposition under the Mineral Leasing Act a portion of Montana known as the Rocky Mountain

Front. Pub. L. No. 109-432, 120 Stat. 2922, tit. IV, § 403 (2006). The law also creates tax incentives for current oil and gas lease owners in the Rocky Mountain Front to sell their leases to the government or a nonprofit organization. The front includes the Rocky Mountain District of the Lewis and Clark National Forest and adjacent lands managed by the BLM.

Congress added approximately 545,000 acres of lands in White Pine County, Nevada, to the National Wilderness Preservation System, Pub. L. No. 109-432, 120 Stat. 2922, div. C., tit. III (2006). In all, a total 14 new wilderness areas were created in White Pine County, Nevada, and the size of the existing Mt. Moriah Wilderness Area was increased. Congress further released from the non-impairment standard of section 603 of the Federal Land Policy and Management Act lands not included in the newly created wilderness areas. Finally, Congress conveyed other lands in White Pine County, Nevada, to the State of Nevada, White Pine County, the U.S. Forest Service, and the U.S. Fish and Wildlife Service. Maps of the new wilderness areas and lands conveyed to other agencies or local governments will be made available by the Secretary of the Interior.

CONGRESSIONAL COMMITTEE CHANGES

With the Democrats taking control of the 110th Congress, the chairmanship of every Senate and House committee changed. A few of the most important changes include: Senator Jeff Bingaman (D-NM) will chair the Senate Energy Committee; Senator Robert Byrd (D-WV) will chair the Senate Appropriations Committee; and Senator Barbara Boxer (D-CA) will chair the Senate Environment and Public Works Committee. Diane Feinstein will serve as chairman of the Senate Subcommittee on Interior and Related Agencies Appropriations. On the House side, the House Resources Committee will be chaired by Nick Rahall (D-WV); and Norman Dicks (D-WA) will chair the House Appropriations Subcommittee on Interior and Related Agencies.

NATIONAL HISTORIC PRESERVATION ACT RENEWED

In Pub. L. No. 109-453, 120 Stat. 3367 (2006), Congress renewed, with minor modifications, the National Historic Preservation Act, 16 U.S.C. §§ 470-470x-6. The National Historic Preservation Act of 1966 (NHPA) constitutes the primary historic preservation legislative authority. To help preserve historic resources, the NHPA authorized the Historic Preservation Fund and the Advisory Council on Historic Preservation (Council). The Historic Preservation Fund provides support to the State Historic Preservation Offices and provides matching grants to states to catalog and preserve historic properties and resources.

The Council is an independent federal agency that works with the Secretary of the Interior to administer the NHPA. The Council helps to administer the Historic Preservation Fund and the National Register of Historic Places. One of the Council's most visible duties is to oversee section 106 of the NHPA. Section 106 requires federal agencies to consider the impacts of their actions on historic resources. The Council is comprised of 20 members, including heads of federal agencies, elected state and local officials, private citizens, and experts in the field of historic preservation.

Public Law No. 109-453 changed the membership, procedures, and authorities of the Council by adding the heads of three

federal agencies to the Council, bringing total membership to 23. The NHPA was also amended to allow the state governor sitting on the Council to appoint a designee with full voting privileges, a right currently given to cabinet secretaries serving on the Council. The new law also gives the Council several new authorities including the authority to seek administrative services from any federal agency or private entity, amending existing law that requires the Council to seek such services solely from the Department of the Interior. The new law also gives the Council the authority to review any federal grant or assistance programs affecting historic resources and subject to provisions of the National Historic Preservation Act. The Council thus has the authority to enter into a cooperative agreement with any agency that administers such a program and participate in the development of grant criteria and the selection of grant recipients.

FOREST SERVICE PLANNING REGULATIONS AND NEPA COMPLIANCE

The Forest Service revised its procedures for implementing the National Environmental Policy Act (NEPA) by issuing a final directive revising the Forest Service Handbook 1909.15, Chapter 30, authorizing the approval of a forest plan, plan amendment, or plan revision to be categorically excluded from NEPA documentation. The modification to the Forest Service Handbook is a continuation of the effort the Forest Service initiated when it issued new planning regulations on January 5, 2005. 70 Fed. Reg. 1023. According to the Forest Service, the changes were designed to modify and streamline Forest Service planning procedures. For additional information regarding the revisions to the Forest Service planning regulations, see Vols. XXI, No. 4 (2004); XXII, No. 1 (2005); XXIII, No. 1 (2006); and XXIII, No. 2 (2006) of this *Newsletter*. As part of the 2005 planning regulations, the Forest Service specifically indicated that the approval of a plan, plan amendment, or plan revision may be categorically excluded from NEPA documentation. The modification to the Forest Service Handbook implements this portion of the 2005 planning regulations by modifying the Forest Service Handbook regarding NEPA procedures. The 2005 planning rules modified and clarified the nature of land management plans, emphasizing their strategic and aspirational nature. The Forest Service is citing language in two recent Supreme Court cases, *Ohio Forestry Ass'n v. Sierra Club*, 523 U.S. 726 (1998) and *Norton v. Southern Utah Wilderness Alliance*, 542 U.S. 55 (2004), in which the Supreme Court determined that forest plans and BLM land use plans typically will not have independent environmental effects, and thus will not have significant environmental effects as defined by NEPA. The new rules were designed to allow individual forests to write new plans in 2-3 years, instead of the 5-7 usually required. Forest Service Chief Dale Bosworth defended the new rules in a letter to leading Democrats in the House, including House Resources Committee Chairman Nick Rahall (D-WA).

Defenders of Wildlife and Forest Guardians have filed a lawsuit in the U.S. District Court for the District of Columbia challenging the Forest Service's decision to add the development of forest plans to the list of agency-approved categorical exclusions. The case is docketed as *Defenders of Wildlife v. Kimbell*, 07-CV-194-RLJ. A lawsuit filed by Defenders of Wildlife, several other non-governmental organizations, and the State of California,

challenging the 2005 planning regulations, is still pending in the U.S. District Court for the Northern District of California, docketed as *Defenders of Wildlife v. Johanns*, 04-CV-4512-PJH.

2005 ROADLESS RULE ENJOINED

As previously reported in Vol. XXIII, No. 4 (2006), of this *Newsletter*, the U.S. District Court for the Northern District of California issued an Order on September 20, 2006, enjoining the Forest Service's adoption of the State Petition for Inventoried Roadless Area Management Rule (2005 Roadless Rule). 70 Fed. Reg. 25,654 (May 13, 2005) (to be codified at 36 C.F.R. pt. 294). The court determined that the promulgation of the 2005 Roadless Rule violated the National Environmental Policy Act (NEPA) and the Endangered Species Act (ESA) because the Forest Service failed to follow procedural requirements imposed by said laws. For a history of the Roadless Rule, see Vols. XX, No. 3 (2003); XXI, No. 3 (2004); and XXII, No. 2 (2005) of this *Newsletter*. The 2005 Roadless Rule was designed to replace the Roadless Area Conservation Rule, 66 Fed. Reg. 3244 (Jan. 12, 2001) (to be codified at 36 C.F.R. pt. 294), which was implemented in the waning days of the Clinton Administration. The 2001 Roadless Rule was the subject of significant litigation in the Eighth, Ninth, and Tenth Circuits and, at the time the 2005 Roadless Rule was promulgated, had been permanently enjoined by a federal district judge in the U.S. District Court for the District of Wyoming. Magistrate Judge Elizabeth D. Laporte of the Northern District of California determined that the 2005 Roadless Rule was issued in violation of both NEPA and ESA and, therefore, enjoined the implementation of the 2005 Roadless Rule and reinstated the 2001 Roadless Rule as issued by the Clinton Administration. In subsequent orders clarifying the terms of the injunction, Judge Laporte enjoined the Forest Service from taking any further action contrary to the 2001 Roadless Rule including, but not limited to, approving or authorizing any management activities in inventoried roadless areas that would have been prohibited by the 2001 Roadless Rule. The court specifically noted that the injunction applies to activities commenced on any and all mineral leases which completed any portion of leasing process after the 2001 Roadless Rule was replaced by the 2005 Roadless Rule in May 2005.

The State of Wyoming has already filed paperwork in the U.S. District Court for the District of Wyoming challenging the 2001 Roadless Rule. The Forest Service has not yet issued guidance for the field offices or line officers to implement Judge Laporte's decision.

NEW LEADERSHIP AT BLM AND FOREST SERVICE

The Bureau of Land Management (BLM) and the U.S. Forest Service will both be under new leadership in 2007. Forest Service Chief Dale Bosworth announced January 12, 2006, that he will retire after almost six years as Chief. The Secretary of Agriculture, Mike Johanns, appointed Abigail Kimbell to succeed to the post. Kimbell is a career Forest Service employee and most recently served as the Regional Forester of the Northern Region. Senate confirmation is not required for the Chief's position and, thus, Kimbell will succeed to the post immediately. On December 28, 2006, Secretary of the Interior Dirk Kempthorne announced the resignation of BLM Director Kathleen Clarke, who became

Director in 2002. A replacement for Clarke has not been named, although any replacement must be confirmed by the full Senate.

FOREST SERVICE ISSUES NEW PLANNING DIRECTIVES FOR WILDERNESS EVALUATION

On January 31, 2007, the U.S. Forest Service issued final directives revising Forest Service Handbook 1909.12, Chapter 70, regarding wilderness evaluation when carrying out national forest land management planning. 72 Fed. Reg. 4478 (Jan. 31, 2007). The directives establish procedures and responsibilities for implementing the 2005 Forest Service planning regulations (see above article). The directives are intended to provide overall guidance to Forest Service line officers and employees in “identifying and evaluating potential wilderness areas when” developing, amending, or revising land management plans for units of the National Forest System. 72 Fed. Reg. 4478 (Jan. 31, 2007). The Forest Service is required to assess lands possessing wilderness characteristics for recommendation as potential new wilderness areas during the land planning process. 36 C.F.R. § 219.7(a)(5)(ii). The new directives may play a significant role in determining whether portions of National Forest System lands are more or less available for resource and commodity development and certain forms of recreation in the future as existing and older forest plans are revised and amended. See Vol. XXII, No. 1 (2005) and Vol. XXI, No. 4 (2004) of this *Newsletter* for a discussion of the history of the Forest Service planning rules and regulations.

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ROBERT C. MATHES
— REPORTER —

EPA ISSUES FINAL SPCC REQUIREMENTS

On December 26, 2006, the Environmental Protection Agency (EPA) amended the Spill Prevention, Control, and Countermeasures (SPCC) Plan requirements by (1) providing an option to allow the owners or operators of facilities with an oil storage capacity of 10,000 gallons or less, and who meet other qualifying criteria to self-certify their SPCC Plans in lieu of review and certification by a Professional Engineer; (2) allowing owners and operators of facilities that have particular types of oil-filled operational equipment to use an oil spill contingency plan along with an inspection or monitoring program as an alternative to secondary containment for qualified equipment without requiring a determination of impracticability; (3) defining “motive power containers”; and (4) exempting mobile refuelers from the specifically sized secondary container requirements for bulk storage containers. The EPA also removed and reserved certain SPCC requirements for animal fats and vegetable oils and extended the compliance dates for farms to comply with the new regulations. 71 Fed. Reg. 77,266 (Dec. 26, 2006) (to be codified at 40 C.F.R. pt. 112).

The final rule modifies the regulations originally issued by the EPA on July 17, 2002, amending the SPCC rule, formerly

known as the Oil Pollution Prevention Regulation promulgated under the authority of section 311(j) of the Clean Water Act (CWA). The 2002 regulations included revised requirements for SPCC Plans, which were more stringent than those previously in effect. The most significant change between the 2002 regulations and those issued in 2006 is the removal of the requirement to have a Professional Engineer certify SPCC Plans for facilities with less than 10,000 gallons of storage capacity in lieu of a self-certification and inspection program. As discussed in previous editions of this *Newsletter*, see Vols. XVIV, No. 3 (2002); XX, No. 1 (2003); and XXIII, No. 2 (2006), the EPA repeatedly delayed the final implementation of the 2002 regulations because of concerns from the industry and litigation challenging the regulations. Under the current regulations a facility that was in operation on or before August 16, 2002, must make any necessary amendments to its SPCC Plan and implement that plan on or before October 31, 2007. Facilities that came into operation after August 16, 2002, must also prepare and implement an SPCC Plan on or before October 31, 2007. 71 Fed. Reg. 8462 (Feb. 17, 2006).

On December 26, 2006, however, the EPA also issued a proposed rule amending the dates by which facilities must prepare or amend and implement SPCC Plans. 71 Fed. Reg. 77,357 (Dec. 26, 2006). The proposed rule would extend the dates in 40 C.F.R. § 112.3(a), (b), and (c), by which a facility must prepare, amend, and implement its SPCC Plan. Facilities that were in operation on or before August 16, 2002, would have to make any necessary amendments to their SPCC Plans, and implement those plans, on or before July 1, 2009. Facilities that came into operation after August 16, 2002, would be required to prepare and implement an SPCC Plan on or before July 1, 2009.

EPA ISSUES NEW AIR EMISSION REGULATIONS FOR DEHYDRATION UNITS

On January 3, 2007, the Environmental Protection Agency (EPA) issued National Emission Standards for Hazardous Air Pollutants to regulate hazardous air pollutant emissions from oil and gas production facilities that are area sources. 72 Fed. Reg. 26 (Jan. 3, 2007). The final rule became effective on January 3, 2007. Pursuant to sections 112(c)(3) and 112(k)(3)(B) of the Clean Air Act (CAA), the EPA issued regulations to reduce hazardous air pollutants from triethylene glycol (TEG) dehydration units at oil and gas production facilities. The regulations were designed to reduce benzene emissions from TEG dehydration units at oil and natural gas production facilities which, according to the EPA, contribute approximately 40% of the nationwide urban area source benzene emissions. The regulations apply to the owners and operators of TEG dehydration units with an actual annual average natural gas flow rate equal to or greater than 85,000 standard cubic meters per day and with benzene emissions equal to or greater than 0.90 Mg/yr or 1.0 tpy. The new regulations apply different control standards for oil and natural gas production facilities located in urbanized areas or urban clusters, areas which contain 10,000 or more people, and more remote areas. For urban areas, dehydration units must be connected, through a closed vent system, to one or more emission control devices that reduce hazardous air pollutant (HAP) emissions by 95% or more, or reduce HAP emissions to an outlet concentration of 20 parts per million by volume or less, or reduce benzene emissions to a level less

than 0.90 Mg/yr. For TEG hydration units located outside of urban areas, the EPA is requiring that each unit reduce emissions by lowering the glycol circulation rate to be less than or equal to an optimum rate pursuant to a formula contained in the regulations designed to reduce emissions. The EPA has provided a two year compliance deadline for existing sources.

GULF OF MEXICO ENERGY SECURITY ACT OF 2006

In its final days the 109th Congress made approximately 585,000 acres of lands in the Gulf of Mexico available for oil and gas leasing under the Outer Continental Shelf Lands Act. Pub. L. No. 109-432, 120 Stat. 2922, div. C, tit. I (2006). The Minerals Management Service (MMS) is required to offer the leases in Area 181 "as soon as practicable, but not later than 1 year, after the date of enactment of this Act." Area 181 is located more than 125 miles off the coast of Florida. On February 14, 2007, the MMS issued a request for information and nominations for the newly available lands, and announced its intention to prepare a supplemental environmental impact statement analyzing the potential impacts of leasing and development. 72 Fed. Reg. 7070 (Feb. 14, 2007). In its Notice of Intent, the MMS indicated that despite the requirement in the Gulf of Mexico Energy Security Act to make the area available for lease, the soonest the lands would be offered would be the previously scheduled March 2008 lease sale. *Id.* at 7071.

ALABAMA — OIL & GAS

EDWARD G. HAWKINS
— REPORTER —

ORAL ARGUMENTS HELD ON APPEAL OF \$3.6 BILLION JUDGMENT IN EXXON CASE

On December 20, 2002, the Alabama Supreme Court reversed and remanded a \$3.5 billion jury verdict in favor of the State of Alabama entered by a Montgomery County Circuit Court jury against Exxon Corp. in a royalty dispute case involving royalty payments under a State of Alabama offshore lease. *Exxon Corp. v. Department of Conservation and Natural Resources*, 859 So. 2d 1096 (Ala. 2002). See Vol. XX, No. 1 (2003) of this *Newsletter*. The reversal turned on the trial court's allowing into evidence a letter by an Exxon in-house corporate lawyer.

Following a November 2003 retrial, a second Montgomery County Circuit Court jury returned a second verdict in the case against Exxon in excess of \$11.8 billion. Gary McElroy, "Mobile Lawyers Broke Record," *Mobile Register*, Dec. 12, 2003, at B1. See Vol. XXI, No. 1 (2004) of this *Newsletter*. In March 2004, the Circuit Court of Montgomery County reduced the punitive damages award to \$3.5 billion, leaving the total trial judgment at \$3.6 billion. David White, "State Court to Hear Exxon Verdict Appeal," *Birmingham News*, Feb. 5, 2007.

Oral arguments on Exxon's appeal to the Alabama Supreme Court were held on February 6, 2007. The oral arguments came more than 2½ years after Exxon appealed the trial court's judgment on the second jury verdict in the case. A decision is expected within a couple of months.

ALASKA — OIL & GAS

RANDAL G. BUCKENDORF
— REPORTER —

STATE OF ALASKA TERMINATES POINT THOMSON UNIT

On November 27, 2006, the Commissioner of the Alaska Department of Natural Resources (ADNR) issued a final administrative decision (Decision) denying the proposed plans for development and terminating the Point Thomson Unit (PTU) on the North Slope of Alaska. Point Thomson is a large natural gas discovery 60 miles east of Prudhoe Bay, near the border of the Arctic National Wildlife Refuge. The 106,000 acre unit is estimated to contain about 9 trillion cubic feet of gas and several hundreds of millions of barrels of gas condensate and crude oil. The first discovery well was drilled at Point Thomson in 1977. In total, 19 exploration or appraisal wells have been drilled in the unit area. The PTU is on state land and is operated by ExxonMobil on behalf of itself and the other unit owners. The Decision, the first of its kind in the state, focused on three critical issues: (1) the PTU owners' plan of development (the 23rd for the PTU) was inadequate because it did not commit to develop and produce hydrocarbons from the unit; (2) the reasonable prudent operator standard does not apply to a unit that contains leases beyond their primary terms; and (3) the PTU does not contain any "certified" wells (wells capable of production in paying quantities) requiring judicial proceedings to terminate the unit. See www.dog.dnr.state.ak.us/oil (click on Point Thomson Unit, then on Commissioner's Decision on Appeal).

In response to the Decision, the PTU owners have taken three actions: First, ExxonMobil asked for immediate reconsideration of the ADNR Commissioner's Decision. Second, the PTU owners, through ExxonMobil as operator and each individually, appealed the Decision to the Alaska Superior Court, raising numerous procedural and substantive issues with the Decision. Third, ExxonMobil filed a complaint in Alaska Superior Court for damages and declaratory and injunctive relief.

To many observers, this current controversy seems like nothing new in the long and often controversial 30-year history of the Point Thomson field. However, oil and gas companies currently doing business in Alaska or those contemplating doing business in Alaska are following the matter very closely due to the sudden departure from past precedent within ADNR and the likely conflict between ADNR, as the leaseholder; the Alaska Oil and Gas Conservation Commission, which has the role of prescribing rules for how development of a field should proceed in order to prevent waste and insure greater ultimate recovery of oil and gas; and the PTU owners, who must evaluate the economics of developing such a large complex gas field in the absence of a gas pipeline from the Alaska North Slope. This latter point is at the very core of the issue.

To say the PTU is a large development is an understatement. At an estimated 9 trillion cubic feet of gas, it is one of the largest discovered, yet undeveloped, gas fields in North America. The field has never been developed because there is no gas pipeline and no way to market the gas. The field is also right next to the

massive Prudhoe Bay field, which contains such a large volume of gas that its production will largely dictate the timing of a natural gas pipeline from the Alaskan North Slope and the size of that line. Finally, the PTU is one of the most difficult fields to develop and manage properly because the majority of the resources are contained in what is called a retrograde condensate reservoir.

Retrograde condensate reservoirs tend to be deeper and generally contain higher pressures and temperatures than conventional reservoirs. These high temperatures cause the oil and gas to react much differently than in the other conventional reservoirs that dot the Alaskan North Slope. These differences in behavior are technically complex and difficult to describe, understand, and reach agreement on how to address in a plan of development. The PTU owners have spent about \$800 million over the years on exploration and development activities, but the various parties still disagree on how the field should be developed.

In the December 27, 2006, Commissioner's Decision on Reconsideration of the November 26, 2006, Point Thomson unit termination Decision, the new ADNR Acting Commissioner, who took office in early December as a result of the recent gubernatorial election in Alaska, confirmed the decision of her predecessor. See www.dog.dnr.state.ak.us/oil (click on Point Thomson Unit, then on Decision on Reconsideration). In her decision, the Acting Commissioner found no merit in the points raised in the request for reconsideration, including what may very well be one of the more pivotal points in the dispute—a departure from long standing ADNR policy to certify exploration wells and wells that have been plugged and abandoned as capable of producing in paying quantities.

The leases issued by the State of Alaska had 10-year primary terms that would have expired sometime in the late 1980s. However, when there is a confirmed discovery, the leases can be extended as long as the discovery is capable of production and the leaseholders are making diligent efforts to develop the leases. As is typical in the oil and gas industry, the leases covering the Point Thomson field were also consolidated in the PTU. Extension of the unit and all of the underlying leases is generally done on a year-by-year basis in the plan of development. In this current dispute, the ADNR Commissioner denied the proposed plans for development of the PTU on September 30, 2005. This decision gave the PTU owners the opportunity to cure the default within 90 days. Because ExxonMobil, BP, and ConocoPhillips were negotiating the fiscal terms of a contract with the State of Alaska, including ADNR, for the construction of a North Slope gas line that also included terms for the development of the PTU, the PTU owners asked for an extension to submit the curative plan of development.

Terms of the proposed natural gas pipeline were reached between the State of Alaska and the three owners in the spring of 2006 and the proposed fiscal contract was submitted for review and comment to the Alaska legislature. Some members of the Alaska legislature reacted negatively to certain aspects of the proposed contract and on October 20, 2006, the PTU owners submitted the curative plan of development. The above decisions followed.

This critical and important decision will be closely watched by all parties in Alaska, especially those that happen to hold leases

and units via certified wells that were likely plugged and abandoned years ago as required by state law of the time.

CALIFORNIA — MINING

PATRICK G. MITCHELL
G. BRAIDEN CHADWICK
— REPORTERS —

AMENDMENTS SET NEW SMARA REQUIREMENTS FOR MINING PROJECTS AND LEAD AGENCIES

Senate Bill 668, which became effective on January 1, 2007, added section 2772.7 to the Public Resources Code and amended section 2774 as follows: Lead agencies must submit a draft response to the Department of Conservation's written comments at least 30 days prior to any approval of a reclamation plan, a plan amendment, or financial assurances.

- Lead agencies must state whether they will adopt the Department of Conservation's comments. If they choose not to adopt the Department's comments, they must state, in detail, their reasons for not doing so.
- Lead agencies must give the Department of Conservation at least 30 days' notice of the time, place, and date of any hearing connected with the approval of a reclamation plan, plan amendment, or financial assurance. If no hearing is required, then the lead agency must still provide 30 days' notice to the Department of Conservation of its intent to approve the reclamation plan, plan amendment, or financial assurance.
- Lead agencies must send their final response to the Department of Conservation's comments within 30 days after approving the reclamation plan, plan amendment, or financial assurance at issue.
- After approving a reclamation plan or an amendment to a reclamation plan, lead agencies must record a Notice of Reclamation Plan Approval with the county recorder using specified language set out in Public Resources Code § 2772.7.

CALIFORNIA SUPREME COURT REJECTS EIR'S WATER SUPPLY ASSESSMENT FOR DEVELOPMENT PLANS

A recent case decided by the California Supreme Court may have significant implications for the water resources assessments that are included in EIRs prepared for mining projects. The decision involved a decision by Sacramento County approving a Community Plan covering approximately 6,000 acres in a formerly unincorporated area but now within the City of Rancho Cordova, as well as a Specific Plan covering 2,600 acres within the Community Plan area. In *Vineyard Area Citizens v. City of Rancho Cordova*, 40 Cal. 4th 412, 150 P.3d 709 (Cal. 2007), a citizen's group challenged the adequacy of the EIR prepared for the Community and Specific Plans.

According to the EIR, the Specific Plan was expected to have an average annual water demand of 8,539 acre-feet, and the total average annual demand for the entire Community Plan area was

expected to be 22,103 acre-feet. The first 5,527 acre-feet would come from the newly developed North Vineyard Well Field. Additional needs would be met through conjunctive use of the Well Field and surface water supplies that would serve the Zone 40 area of the county, which included the Community Plan area. The EIR relied, in part, on the study completed as part of the analysis supporting the Water Forum Agreement, a collaborative effort among various local agencies to analyze collective water demands along the American River. Because the property owners of the development did not own the rights to surface or groundwater resources, a mitigation measure was developed that required agreements and financing for additional water supplies to be in place before additional entitlements (e.g., subdivision maps) could be granted.

The California Supreme Court reversed and remanded the decision of the 3rd District Court of Appeal, which had ruled for the defendants, finding: (1) that the Environmental Impact Report for a large land use development failed to adequately identify and evaluate long-term water sources and failed to disclose the impacts of providing long-term supplies; and (2) that the potential impacts to migratory salmon should have been discussed in a revised Draft EIR and recirculated for public comment.

The court began its analysis with an overview of water supply planning cases and statutes, summarizing the general principles as follows:

- An EIR cannot ignore or assume a solution to a problem of supplying water to a land use project.
- An EIR for a large project to be built over a number of years cannot limit its analysis to the water supply for the first stage or first few years of a project, nor can it defer the analysis of future water sources and the impacts of exploiting those sources to a future tier EIR, but must assume that all phases will eventually be built and must analyze, to the extent reasonably possible, the impacts of providing water to the entire proposed project.
- The water supplies that are analyzed must bear a likelihood of actually proving available—speculative sources and unrealistic allocations or paper water are not sufficient bases for decision-making.
- When uncertainty about actual availability remains, the EIR must discuss possible replacement sources or alternatives to use of the anticipated water and analyze the environmental impacts of those alternative strategies—such a discussion could include the use of a measure for capping development if water sources do not materialize, but such a measure absent the rest of the analysis would be insufficient.

The court made clear, however, that the California Environmental Quality Act (CEQA) does not require a long-term large-scale project to have absolute certainty through signed agreements and approved treatment and delivery facilities at the time of initial approval.

The court summarized pertinent portions of S.B. 610 and S.B. 221, which require water supply assessment at the planning stages and water supply verification at the subdivision map stage, and concluded that the “burden of identifying likely water sources for a project varies with the stage of project approval involved,”

but that under CEQA the question is “not whether an EIR establishes a likely source of water, but whether it adequately addresses the reasonably foreseeable *impacts* of supplying water to the project.” 40 Cal. 4th at 434. The court concluded:

If the uncertainties inherent in long-term land use and water planning make it impossible to confidently identify the future water sources, an EIR may satisfy CEQA if it acknowledges the degree of uncertainty involved, discusses the reasonably foreseeable alternatives—including alternative water sources and the option of curtailing the development if sufficient water is not available for later phases—and discloses the significant foreseeable environmental effects of each alternative, as well as mitigation measures to minimize each adverse impact.

Id.

Importantly, the court acknowledged that, rather than reinvent the wheel for each new development plan, an agency could incorporate information and analysis from its urban water management plan into an individual project’s CEQA analysis so long as the project’s demand was accounted for in the overall plan.

The court also concluded that the EIR’s analysis of *near-term* water supplies was adequate because the record contained “substantial evidence” (in the form of, among other things, pipeline construction plans and per unit fees) “demonstrating a reasonable likelihood” that the Well Field would be available “at least in substantial part” to supply the project’s near term needs. The court found, however that the EIR’s analysis of *long-term* water supplies was *not* adequate because the EIR failed to provide a clear, consistent description of water demand associated with future growth in the Zone 40 area and new surface water supplies that may be available to serve that growth. The court pointed to apparent discrepancies between the supply and demand calculations in the Water Forum EIR and the Community Plan/Specific Plan EIR and discounted the EIR’s discussion of the plan for “conjunctive use” of surface and groundwater to explain the gap between potential surface water supplies and projected demands, agreeing with plaintiffs and amicus curiae that the EIR’s reliance on a conjunctive use program lacked appropriate quantification to disclose whether the program would produce adequate supply and storage capacity to meet demands. To the extent the EIR relied on a future Zone 40 master plan update to provide a detailed analysis of the conjunctive use program, the court considered that reliance to be an improper attempt to tier from a future document.

The court questioned the EIR’s adequacy as an informational document because the quantitative analysis of long-term supply and demand for the Zone 40 area was incomplete and the missing analysis could not be easily deduced from the information provided. While the County’s burden was “not necessarily to demonstrate with certainty that the County’s total water supply in the year 2030 would be sufficient to meet its total demand . . . CEQA did require that the [EIR] show a *likelihood* water would be available, over the long term, for this project.” *Id.* at 441. Without an explanation showing “at least an approximate long-term sufficiency in total supply,” the court stated, “the public and decision makers could have no confidence that the identified sources were actually likely to fully serve this extraordinarily large development project.” *Id.*

The court found that the County could not rely on mitigation in the Water Forum EIR because the Community/Specific Plan EIR failed to expressly incorporate the earlier document's analysis and mitigation by reference. The court also concluded that, while a mitigation measure precluding further development if water supplies did not materialize could *supplement* the discussion, it could not *substitute* for the requisite analysis of likely water sources. The court classified the lack of analysis as a procedural defect, while it considered the inconsistent figures to be factual flaws. Finally, the court held that the EIR should have been recirculated to evaluate effects of groundwater extraction on river levels and, in turn, on river habitats, particularly for salmon.

In an 11-page opinion partially concurring and partially dissenting, Justice Baxter characterized the majority's holding as a "new rule" that held the project applicant hostage to "a balancing of supply and demand for all conceivable development that is not prohibited by the County's general plan. . . ." *Id.* at 452. He argued that the standard set by the majority for an analysis of long-term water supplies was not based in any statute or prior caselaw or even in the arguments of the plaintiffs, and that a similar approach had actually been rejected by the California legislature while developing S.B. 901 (the predecessor to S.B. 610). He also argued that the majority's analysis of the long-term supply issue was inconsistent with its conclusions regarding short-term supply.

COLORADO — OIL & GAS

SHERYL L. HOWE
— REPORTER —

COURT RULES ON PREEMPTION ISSUES RAISED BY COUNTY REGULATIONS REGARDING OIL AND GAS OPERATIONS

Board of County Commissioners v. BDS International, LLC, No. 04CA1679, 2006 WL 3627604 (Colo. Ct. App. Dec. 14, 2006) (not released for publication), addresses whether Gunnison County's regulations related to oil and gas operations are preempted by state or federal law. BDS had not sought a county permit under the regulations, and Gunnison County sued to enforce its regulations. The trial court granted partial summary judgment in favor of defendant BDS and intervenor the Colorado Oil and Gas Conservation Commission (COGCC). Gunnison County appealed the trial court's decision.

The trial court invalidated certain county regulations based on operational conflicts with the state regulatory scheme. The court noted that BDS had not applied for a permit from Gunnison County. The court of appeals stated that, therefore, in determining whether there was an operational conflict between a state law or regulation and the county regulations, the court would construe the county regulations, if possible, so as to harmonize them with the state statutes and regulations.

The court of appeals agreed with the trial court's finding that county regulations imposing financial requirements and requiring operators to give the county access to their records were preempted by state law. *Id.* at *4. The county regulations on these matters related to impact mitigation costs and allowed the county to set the amount of a security agreement at no less than 125% of the

estimated cost of conditions to be performed, payable on demand to the county. The other regulation gave the county access to operators' books and records. The court of appeals reviewed the COGCC rules on fines ("which shall be imposed only by order of the Commission"), bond requirements, and the obligation of operators to keep their records available for examination by the COGCC, and concluded that the county regulations on these matters are preempted by state law. *Id.* at *4-5. The trial court's summary judgment invalidating these county regulations was upheld by the court of appeals.

The county regulations also addressed a number of other areas and as to these the court of appeals found that summary judgment was inappropriate and that an evidentiary hearing is required to determine whether there are operational conflicts between the county regulations and state law. *Id.* at *4. The court quoted *Board of County Commissioners v. Bowen/Edwards Associates, Inc.*, 830 P.2d 1045 (Colo. 1992), as holding that a trial court must determine the extent of an operational conflict "on an ad-hoc basis under a fully developed evidentiary record." 830 P.2d at 1060. The court of appeals found that summary judgment was inappropriate and that an evidentiary hearing needs to be held on the county regulations pertaining to water quality, soil erosion, wildlife, vegetation, livestock, geologic hazards, cultural and historic resources, wild-fire protection, recreation impacts, and permit duration. The court of appeals found that these county regulations "may possibly be harmonized with the state regulatory scheme and, therefore, an evidentiary hearing is necessary to determine the extent of any operational conflicts in this case." 2006 WL 3627604 at *3. The court's decision does not analyze in depth any possible operational conflicts and instead sends these regulations back to the trial court for an evidentiary hearing on the conflict issue.

The court of appeals also found that the county regulations are not impliedly preempted by federal law. *Id.* at *8. The court stated that Colorado's appellate courts have not previously addressed whether the federal regulatory scheme impliedly preempts all local regulation of oil and gas operations on federal lands. The court of appeals relied on a Wyoming case and a case from the Tenth Circuit and rejected the implied preemption argument. The court relied on the fact that this case was a challenge to the facial validity of the county regulations to distinguish it from a Colorado case finding federal preemption.

Two petitions for certiorari have been filed with the Colorado Supreme Court.

LOUISIANA — OIL & GAS

EDWARD B. POITEVENT, II
— REPORTER —

LOUISIANA FEDERAL COURT DISMISSES SUIT ALLEGING ACTIVITIES OF OIL AND GAS AND PIPELINE COMPANIES CONTRIBUTED TO DESTRUCTION CAUSED BY HURRICANES KATRINA AND RITA

A Louisiana federal district court has dismissed an action alleging that activities of oil and gas producing companies and pipelines destroyed Louisiana's coastal marshlands and thereby contri-

buted significantly to the destructive impact of Hurricanes Katrina and Rita in the fall of 2005.

In a case arising out of the destructive impact of Hurricanes Katrina and Rita on the Louisiana coastline, *Barasich v. Columbia Gulf Transmission Co.*, Nos. 05-4161, 05-4569, 2006 WL 3333797 (E.D. La. Sept. 28, 2006), various class actions (later consolidated) were filed in the Eastern District of Louisiana seeking damages against various oil and gas producing companies and pipeline companies due to their activities that were alleged to contribute significantly to the destructive impact of the storms in south Louisiana. In effect, the plaintiffs asserted that the defendants' actions had damaged Louisiana's marshlands lying between its habitable regions and the Gulf of Mexico, which weakened the protective barrier against Hurricanes Katrina and Rita, and thereby exposed Louisianans to greater harm from the storms than would have occurred otherwise.

The plaintiffs alleged that, over many decades, the oil and gas exploration and production and pipeline companies named as defendants had dredged canals through the Louisiana marshlands and had decimated millions of acres by significantly and harmfully altering the hydrology of the marshes. In turn, this activity was alleged to allow salt water intrusion into the marshlands resulting in their erosion. It was also alleged that the defendants had created spoil banks that then limited tidal and fresh water flows essential for the maintenance of the marshlands. All of this was alleged to have deprived inland communities, such as the City of New Orleans and St. Bernard Parish, Louisiana, of their natural protection from hurricane winds and accompanying storm surges.

The plaintiffs also alleged that the defendants knowingly failed to maintain the canals and allowed numerous breaks or cuts to develop and enlarge the spoil banks, which consequently further eroded the marshlands. Plaintiffs further asserted that as a direct result of the defendants' actions in the Louisiana marshlands, the plaintiffs and other class members had sustained personal injury and death, property damage, and the loss of the wetlands' value as storm protection.

The defendants filed a joint motion to dismiss the plaintiffs' claims on the bases that (1) there was no subject matter jurisdiction because the matter concerned a political question, and (2) the plaintiffs did not state a claim upon which relief could be granted because they could not prove the requisite elements for recovery as a matter of law under any available theory.

The Louisiana federal district court held that the plaintiffs' case was merely a tort suit under Louisiana law and thus did not present a nonjusticiable political question, as that doctrine is set forth in *Baker v. Carr*, 369 U.S. 186 (1962). It then noted that, in a case most analogous to the one presented, *Gordon v. Texas*, 153 F.3d 190, 195 (5th Cir. 1998), the Fifth Circuit had held that coastal erosion is not an area in which courts are unable to determine judicially manageable standards and noted that the facts in that case were similar to the ones at issue in this matter in several significant ways. As the plaintiffs' action was merely a tort suit under Louisiana law, the politically charged context did not alter this and transform the case from an ordinary tort suit into a nonjusticiable political question.

The court further rejected the defendants' allegations that the matter presented a nonjusticiable political question on the basis

that the federal government had permitted the dredging of canals in Louisiana's marshlands under the jurisdiction of various federal agencies, including the U.S. Army Corps of Engineers. In summary, on this point the court noted as follows:

The Court is aware that from the face of the plaintiffs' complaint this could be a complex case to adjudicate. But that does not necessarily turn the plaintiffs' lawsuit into a nonjusticiable political question. The Court does not find that the plaintiffs' claims implicate the political question doctrine as set forth in *Baker v. Carr*.

2006 WL 3333797, at *11.

Next, the defendants asserted that the plaintiffs' claims did not support recovery under any theories of applicable Louisiana law. First, they argued that the plaintiffs' claims did not support an action under Louisiana Civil Code Article 667 which, in effect, prohibits one "neighbor" from making works on his property that might deprive another of the liberty of enjoying his own property. The court held that the plaintiffs' case could not be sustained on this basis because Louisiana law limits the sweep of Article 667 to relationships between property owners that are "characterized by proximity," 2006 WL 3333797, at *13, i.e., the obligation of one of those living in a general "neighborhood" not to harm his or her "neighbors." It noted as follows: "Plaintiffs' Article 667 claim fails because they do not demonstrate that the "neighbor" referred to in Article 667 could be a party whose property is physically remote from that of the defendants." *Id.*

As the plaintiffs had asked for a finding of liability between parties whose properties are hundreds of miles apart in many cases, the court found that there was no "neighborhood" or "neighbor" relationship under Article 667.

Second, defendants argued that Article 2315 of the Louisiana Civil Code, which imposes tort liability on those who inflict negligent damage on another, requires the application of a duty-risk analysis to determine liability, which the plaintiffs could not sustain. The court agreed that the plaintiffs could not establish that the defendants owed the plaintiffs a duty or that the defendants' conduct was a cause-in-fact of their injuries. Thus, it noted as follows:

For plaintiffs to recover in this matter, they must demonstrate as a matter of law that defendants had a duty to these hundreds of thousands of plaintiffs to protect them from the results of coastal erosion allegedly caused by operators that were physically and proximately remote from plaintiffs or their property. Because the Court finds no case assigning such a broad duty to a defendant under Louisiana law, it must decide the issue the way that it believes the Louisiana Supreme Court would decide it. Based on its recent holding in *Terrebonne Parish School Board [v. Castex Energy, Inc.]*, 893 So. 2d 789 (La. 2005), (court declined to imply a general duty to restore surface of a mineral lease to its pre-lease condition)], this Court believes that the Louisiana Supreme Court would find that defendants do not owe the plaintiffs a duty as a matter of law.

....

The Court has not found a controlling or persuasive case at all similar to that proposed by plaintiffs, in which

a plaintiff could collect damages from an industry as a whole without demonstrating any individual connection between any single member of the industry and the plaintiff's harm, and in which liability would be assessed against industry defendants on a group liability theory. The court concludes that such cases do not exist because they would subvert the notion of causation that underlies the system of tort liability in Louisiana. . . . Plaintiffs thus fail to state a claim upon which the Court could possibly grant recovery.

2006 WL 3333797, at *16-18.

Third, the court agreed with the defendants that Louisiana Civil Code Article 2317 did not provide a basis for the defendants' liability. Article 2317 provides that parties are responsible not only for the damage they create by their own acts, but also for the acts caused by persons for whom they are answerable, with certain limitations. The court found that because the plaintiffs did not satisfy the causation-in-fact requirement under Article 2315 and that, because the test for causation under Article 2317 is the same, Article 2317 thus did not provide a basis for liability.

In closing, the court noted as follows:

By all accounts, coastal erosion is a serious problem in south Louisiana. If plaintiffs are right about the defendants' contribution to this development, perhaps a more focused, less ambitious lawsuit between parties who are proximate in time and space, with a less attenuated connection between the defendant's conduct and the plaintiff's loss, would be the way to test their theory. In the absence of such a case, for the foregoing reasons, the court finds that plaintiffs fail to state a claim upon which relief may be granted. . . .

Id. at *18.

The court thus granted the defendants' motion and dismissed the plaintiffs' claims.

MONTANA — OIL & GAS

COLBY L. BRANCH
STEVEN P. RUFFATTO
— REPORTERS —

DOCTRINE OF TEMPORARY CESSATION AFFIRMED — DISCOVERY RULE IMPLICATIONS

The Montana Supreme Court in *Somont Oil Co. v. A&G Drilling, Inc.*, 2006 MT 90, 332 Mont. 56, 137 P.3d 536 (Mont. 2006) (*Somont II*) affirmed its strict view of the doctrine of temporary cessation of production as it applies to oil and gas leases. Pursuant to the doctrine of temporary cessation, a temporary interruption in production will not cause an oil and gas lease to terminate, so long as the lessee works with reasonable diligence to restore production within a reasonable time. The Montana court, however, has taken a strict view of the doctrine, holding that a cessation of production may be deemed "temporary" only if initially caused by a sudden stoppage of the well or a mechanical breakdown. *See*

Somont Oil Co. v. A&G Drilling, Inc., 49 P.3d 598 (Mont. 2002) (*Somont I*).

As previously reported (*see* "Doctrine of Temporary Cessation Adopted," Vol. XX, No. 1, at 14 (2003) of this *Newsletter*), our story begins when Somont offered to buy from A&G (and related entities) a number of old oil and gas leases, most of which had been held by production since the 1920s. When A&G declined the offer, Somont acquired new leases from A&G's lessors, and then sued to compel release of the old leases.

At trial, Somont presented evidence of a lack of production from several of A&G's oil and gas leases. A&G argued that the lack of production was justified as a temporary cessation, and presented evidence of reduced oil prices, a deflated economy, and the company's financial pressures as justification for the cessation. The district court instructed the jury to consider "all surrounding circumstances" in determining whether A&G's leases had terminated for lack of production. The jury found that none of the subject leases had terminated, and also found that Somont had wrongfully interfered with A&G's contractual and business relationships.

On appeal, the supreme court was charged with determining whether the district court erred in allowing the jury to consider oil prices, economic considerations, and A&G's financial condition in determining whether A&G's oil and gas leases had terminated due to lack of production. The court, in *Somont I*, first adopted the doctrine of temporary cessation as a means of limiting the harshness of the rule of automatic lease termination. It then noted a jurisdictional dichotomy with regard to what constitutes a temporary cessation. In some states, the court stated, an oil and gas lease will not be terminated for lack of production in paying quantities unless the period of cessation, *viewed in light of all the circumstances*, is for an unreasonable time. 49 P.3d at 604. Other states limit application of the doctrine of temporary cessation primarily to mechanical breakdowns.

The Montana court chose to adopt the latter rule, thereby limiting application of the doctrine of temporary cessation to those circumstances in which the cessation is caused by "a sudden stoppage of the well or a mechanical breakdown of the equipment used in connection with the well, or the like." 49 P.3d at 606. Therefore, in Montana, the analysis as to whether an oil and gas lease has terminated due to lack of production in paying quantities must now proceed under two separate inquiries.

First, a court must determine whether in fact the lease is producing in paying quantities. This is where economic and equitable considerations enter. If, and only if, it is determined that the lease is *not* producing in paying quantities, will the inquiry shift to whether the cessation is temporary or permanent. Under this prong, neither economic nor equitable principles factor into the equation. The cessation must be caused by a sudden stoppage or mechanical breakdown, and the lessee must exercise reasonable diligence to restore production within a reasonable time.

The court in *Somont I* stated that Somont had established at trial that A&G's leases had failed to produce in paying quantities during the accounting period prescribed by the district court. Because A&G had presented its evidence under a "misinformed" interpretation of the doctrine of temporary cessation, however, the supreme court remanded the matter to district court for trial in

accordance with the doctrine of temporary cessation as adopted in *Somont I*.

Upon remand, the district court interpreted *Somont I* as holding that A&G's leases had failed to produce in paying quantities as a matter of law, and so limited the second trial to the question of whether the cessation in production was temporary or permanent. It also precluded A&G from introducing testimonial evidence as to the cause of non-production not previously produced at the depositions of its corporate designees. Further, the district court precluded A&G from producing evidence of restoration of production after the day *Somont* first wrote to A&G claiming that some of its leases had terminated for non-production. As a result of these exclusions, the jury was provided no information whatsoever regarding the majority of the down wells.

At the close of evidence, *Somont* moved the court to enter judgment as a matter of law, stating that there was insufficient evidence to show that the cessation of production on the contested leases was caused by a sudden stoppage, a mechanical breakdown, or the like. The motion was denied, and the jury returned a verdict favorable to A&G on five of the leases. *Somont* renewed its motion for judgment as a matter of law with regard to the five leases on which it did not prevail.

In *Somont II*, the supreme court affirmed the trial court's interpretation of *Somont I*, and thereby affirmed the trial court's refusal to reopen the question of whether A&G's oil and gas leases were producing in paying quantities. Due in part to the other evidentiary exclusions by the trial court, the supreme court found a complete lack of evidence as to why the majority of wells failed to produce and whether repairs were undertaken within a reasonable time. It therefore reversed, and held that the trial court erred in denying *Somont*'s motion for judgment as a matter of law.

The *Somont* cases do *not* disturb Montana's long-standing jurisprudence with regard to the discovery rule. As adopted by the Montana Supreme Court, this rule holds that the *discovery* of natural gas prior to expiration of the primary term of an oil and gas lease in itself constitutes production in paying quantities for purposes of satisfying the habendum clause, thereby extending the lease for so long as the lessee uses reasonable diligence in marketing the gas. See "Discovery Rule Confirmed," Vol. XXI, No. 2, at 8 (2004) of this *Newsletter*. Therefore, in the event of a true lack of market, a lease *capable* of producing natural gas in paying quantities will be *deemed* to be producing in paying quantities so long as the lessee is using reasonable diligence to market the product, and a Montana court will never reach the issue of temporary cessation.

It is less clear whether Montana's discovery rule applies to oil wells. The Montana Supreme Court has so far applied the discovery rule only in cases involving gas wells capable of producing in paying quantities, but shut in for want of market. In such cases, the Montana court has generally distinguished between oil and gas, in that oil may be stored and trucked to market, while the marketing of gas requires a pipeline. See, e.g., *Severson v. Barstow*, 103 Mont. 526, 63 P.2d 1022 (Mont. 1936); *Christian v. A.A. Oil Corp.*, 161 Mont. 420, 506 P.2d 1369 (Mont. 1973). The court's dicta indicates that the discovery rule would apply to natural gas only. See *Severson*, 63 P.2d at 1024 ("a different rule prevails with

relation to oil wells, as oil, unlike gas, may be stored and divided. . . .").

Yet, the Ninth Circuit, interpreting Montana law, has applied the discovery rule to preserve a lease capable of producing oil only, where the production of oil had temporarily ceased for want of market. *Stimson v. Tarrant*, 132 F.2d 363 (9th Cir. 1942). The Ninth Circuit reached this result because it felt that the "general spirit" of *Severson* outweighed the Montana court's dictum in that case. *Stimson*, 132 F.2d at 365.

Sixty years later, the Montana court in *Somont I* seemed to agree. After noting the result in *Stimson*, the Montana court states: "Our holding today has done nothing to disturb the principles discussed in *Stimson* and *Christian*. The equitable notions contemplated therein remain valid considerations but apply only to the 'producing in paying quantities' prong of the two-part test." *Somont I*, 49 P.3d at 606.

It is therefore possible that the discovery rule may apply in Montana to both oil and gas wells, given a complete lack of market. If so, we then circle all the way back to the beginning: is there a point at which the market may become so dismal that an operator may choose to temporarily shut in his oil well, and yet preserve its lease?

THE FINEST LOYALTY

As a service to those whose memories of law school have grown dim through work and worry, your reporters now present the case of *Textana, Inc. v. Klabzuba Oil & Gas*, No. DV-02-215 (12th Mont. Jud. Dist., Dec. 4, 2006). This state district court case illustrates what can happen when Judge Cardozo meets the oil field.

From 1976 through 1997, John O. Brown entered into annual written contracts under which he agreed to perform landman and other services for Robert Klabzuba. Brown was to investigate oil and gas opportunities in north central Montana and to report and present all such opportunities to Klabzuba. Geologic analysis would be conducted by Klabzuba, who would identify suitable prospects and direct Brown as to which areas to lease.

Pursuant to the contracts, Brown was to assign to Klabzuba an undivided 75% interest in all oil and gas leases acquired, keeping the option to participate in the remaining 25% interest at cost. Brown operated most of the wells in which the parties shared an interest. Essentially, Klabzuba relied on Brown to function as his land office in Montana, and to serve as his "eyes and ears" on the ground.

The contractual arrangement terminated on January 1, 1998. Presumably thereafter, Klabzuba learned that in 1983 Brown had acquired oil and gas leasehold interests covering two half-sections of land on which were located producing wells (the Starcher Leases). After acquiring these interests, Brown transferred them to Textana, Inc., a corporation he controlled. Twenty years after acquiring the Starcher Leases (and some five years after termination of the last service contract) Brown drilled three new wells on the leased premises.

Finding that Brown had violated his fiduciary duties to Klabzuba, and had wrongfully concealed his acquisition of the Starcher Leases, the jury awarded Klabzuba a 75% interest in the Starcher Leases, together with \$1,483,232.41 damages for past production.

Accordingly, the court imposed a constructive trust on 75% of Brown's interest in the Starcher Leases and wells, and ordered Brown to execute an assignment of that interest within 30 days. The court further ordered Brown to transfer operational control of the wells to Klabzuba, awarded prejudgment interest in the amount of \$485,515.54, and imposed statutory interest (10%) on the outstanding balance until paid. Finally, the court refused Brown's request to reduce the damages by the amount he had invested in developing the properties. Because the jury found that Brown acted with actual malice and actual fraud in acquiring the properties for himself, the court would not allow Brown to claim that he acted in "good faith" in developing the properties, and so refused the offset.

OKLAHOMA — OIL & GAS

JAMES C.T. HARDWICK
— REPORTER —

NONOPERATOR'S ACQUISITION OF MAJORITY INTEREST IN UNIT DOES NOT JUSTIFY CHANGE OF OPERATOR

In *Chaparral Energy, L.L.C. v. C. E. Harmon Oil, Inc.*, 149 P.3d 1070 (Okla. Civ. App. 2006), Chaparral acquired, in 2003, 86% of the working interest in a fieldwide unit established some 38 years earlier by a Corporation Commission approved Plan of Unitization. Previously, in 1995, Charles Harmon acquired a 10% working interest and then assigned a 1% working interest to Harmon Oil, the latter becoming operator. When Harmon Oil refused to relinquish operations following Chaparral's acquisition, Chaparral brought proceedings before the Corporation Commission seeking to remove Chaparral as operator. The Commission denied removal.

On appeal, the court first considered the removal provisions in the Plan of Unitization. The Plan provided that the Operating Committee, composed of representatives of each lessee in the unit having at least a 10% interest and voting in accordance with their percentage unit participation, could remove the operator by affirmative vote of at least 90% of the voting interest remaining after excluding the voting interest of the operator. Chaparral's attempt to remove Harmon had the support of owners that would have met the 90% voting interest requirement if the interest of both Harmon Oil and Charles Harmon were excluded. However, if Charles Harmon were allowed to vote, his interest was sufficient to block removal of Harmon Oil as operator. Chaparral argued that Harmon Oil was the alter ego of Charles Harmon and, therefore, Charles Harmon was not eligible to vote on operator removal. The court concluded that the Corporation Commission had the authority to decide the alter ego issue in the context of determining eligibility to vote pursuant to its unitization order, citing *Pennmark Resources Co. v. Oklahoma Corporation Commission*, 6 P.3d 1076 (Okla. Civ. App. 2000). However, the court distinguished the finding of alter ego made in the *Pennmark* decision, concluding that the Corporation Commission did not need to reach the alter ego issue here because Chaparral had failed to put on evidence that it had complied with the Plan's procedure for operator removal.

Chaparral then contended that its purchase of a majority interest in the unit was a change of conditions that warranted modification of the Plan of Unitization, in particular, a change of operator. In concluding that Chaparral's acquisition was not a substantial change of conditions or substantial change in knowledge of conditions subsequently occurring sufficient to authorize modification of the Commission's prior order and avoid the stricture prohibiting a collateral attack upon a Commission order, the court stated that the change of conditions must relate to a material alteration in the feasibility of recovering the minerals and the prevention of waste. The court concluded a change in working interest ownership is not such a change of conditions or knowledge of conditions that affects the feasibility of recovering minerals from the reservoir. The court, thus, rejected Chaparral's argument and affirmed the Commission's decision.

CONFLICT OF INTEREST OF CLASS REPRESENTATIVE DOOMS CERTIFICATION OF SETTLEMENT CLASS

In *Cactus Petroleum Corp. v. Chesapeake Operating, Inc.*, No. 102,588 (Okla. Civ. App. Div. III, Dec. 22, 2006) (not for official publication), the court considered the propriety of the trial court's certification of a settlement class for the purpose of approving a settlement of claims asserted by Cactus Petroleum, as class representative, on behalf of working interest owners in various oil and gas wells owned and operated by Chesapeake Operating, Inc. The claims concerned Chesapeake's billing practices. At issue in this appeal were marketing fees charged by Chesapeake when it had marketed production for nonoperators pursuant to its authority under joint operating agreements. For a portion of the period in question, Chesapeake's wholly-owned marketing affiliate, Chesapeake Energy Marketing, Inc. (CEMI), retained as a marketing fee 2% of the price it received for marketing gas, a percentage that was later increased to 3%. Also, during a portion of the period, Chesapeake charged a flat-rate fee of \$0.20 per barrel for marketing oil, an amount that was later increased to \$0.30 per barrel.

In April 2004, the plaintiffs filed a class action against Chesapeake on behalf of all working interest owners in wells and units operated by Chesapeake where Chesapeake marketed hydrocarbons through related entities and collected either directly or through revenue reductions charges arising from sales or services performed by those entities (and other costs not at issue in the appeal). Chesapeake had obtained marketing authorization letters from some but not all of the putative class.

A November 2004 mediation resulted in a settlement that allocated \$2 million to the marketing fee claim. The settlement divided the marketing fee claim into two parts, a so-called "price differential" or "margin" claim and a "fixed percentage marketing fee" claim. The fixed percentage marketing fee claim consisted of the 2% and later 3% fee charged by CEMI for marketing gas, and the \$0.20 per barrel, later \$0.30 per barrel, charged for marketing oil. The price differential, or margin component, was comprised of a marketing margin realized by CEMI on its resale transactions. It was represented by the lesser of index price or CEMI's resale price that CEMI paid under its gas purchase contracts to the extent such lesser amount exceeded the 2% of resale price. The settlement allocated no value to the fixed percentage marketing fee,

notwithstanding that not all class members had signed letters agreeing to that fee.

Following a hearing for approval of the class settlement, the date for a fairness hearing was set and notice was sent to the class affording the class members three options: (1) approval of the proposed class by doing nothing, (2) opt out of the settlement class by a date certain, or (3) remain a member of the settlement class but object to the settlement. Two persons, as Objectors, timely filed notice of intent to object to the proposed settlement. On August 25, 2005, the trial court entered its order finding the settlement was fair, reasonable, and adequate to the settlement class. From this, the Objectors appealed.

On appeal, the class representative argued that the Objectors' appeal should be dismissed because they lacked standing since they had failed to intervene prior to their appearance at the fairness hearing. The court of civil appeals noted the U.S. Supreme Court's decision in *Devlin v. Scardelletti*, 536 U.S. 1 (2002), which had held that the right to appeal was not a matter of standing, but one of whether the class members are parties to the proceeding, and concluded that as long as the appellants objected in a timely manner to approval of settlement at the fairness hearing, those persons could bring an appeal without first intervening. The court of civil appeals rejected the class representative's attempts to distinguish *Devlin* on the basis that it applied only to unnamed class members who are not afforded the opportunity to opt out, and held the Objectors had the right to appeal.

The court then noted that, for approval of a settlement class, the requisites of Okla. Stat. tit. 12, § 2023(A), requiring numerosity, commonality, typicality, and adequacy of representation, must be met, as well as satisfaction of one of the criteria of § 2023(B), and that failure to meet any one of the requisites of § 2023(A) would render certification improper. The court of civil appeals focused upon the Objectors' argument that the adequacy of representation requirement had not been met. The Objectors argued that there was a conflict between the interests of the class representative, who had consented to the fixed percentage marketing fee, and those class members who, like the Objectors, had not consented to that fee. Because of the class representative's consent to the fixed percentage marketing fee, it had no real interest in investigating the merits or in obtaining a reasonable settlement of that claim. This, the Objectors noted, was underscored by the fact that the settlement included "zero recovery" for the fixed percentage marketing fee claims. A review of the evidence presented by the class representative's expert on his evaluation of claims and his statement that counsel had not asked him to include the percentage marketing fee in his calculation, confirmed the court's concerns that the Objectors' interest had not received adequate protection by the class representative. The court concluded that the record revealed an intra-class conflict which prevented the class representative, during settlement negotiations, from having the same interest and the same injury as those class members that had not consented to the percentage marketing fee. In a 2-1 decision, the court concluded that the requirements for class certification had not been met.

As of this report, the class representative's petition for rehearing has been denied and a petition for certiorari to the Oklahoma Supreme Court is pending.

SOUTH DAKOTA — MINING

MAX MAIN
— REPORTER —

IN SITU LEACH MINING RULES APPROVED

In 2006, the legislature authorized the Board of Minerals and Environment to promulgate rules regarding the "requirements for construction, operation, monitoring, and closure of uranium and other mineral mines using in situ leach processes." S.D. Codified Laws § 45-6B-81(10). Board staff began drafting rules in the fall of 2006, and a preliminary draft was released for public comment in December 2006. After making changes based on the preliminary comments, a public hearing on the proposed rules was held January 18, 2007. The proposed rules were extensive, with some 65 new definitions and 59 new sections, covering 100 pages.

At the conclusion of the public hearing on January 18, the Board made limited changes and then adopted the proposed rules as changed. The adopted rules will be codified at S.D. Admin. R. 74:29:01:01 and S.D. Admin. R. ch. 74:29:11. The rules now go before the Interim Rules Review Committee. The rules take effect 20 days after they are filed with the Secretary of State. S.D. Codified Laws § 1-26-8.

TEXAS — OIL & GAS

WILLIAM B. BURFORD
— REPORTER —

BAD LEASE DESCRIPTIONS RENDER PARTICIPATION AGREEMENTS UNENFORCEABLE

Long Trusts v. Griffin, 50 Tex. Sup. Ct. J. 209, No. 04-0825, 2006 WL 3524376 (Tex. Dec. 8, 2006) (per curiam), vividly illustrates the importance of clear land descriptions in oil and gas agreements.

In a series of agreements made in 1978 and 1982, the Griffins' group agreed to pay a share of the Long Trusts' drilling and operating costs in exchange for assignments of working interest in producing gas wells. The arrangement continued successfully for years but, when disputes arose, the Long Trusts asserted that the agreements were unenforceable with respect to any further drilling because they did not sufficiently identify the properties intended to be covered. The supreme court agreed, reversing judgments of the trial court and the court of appeals.

The 1978 agreements, to describe the leases in which the Griffins were entitled to participate, stated they were located "in the Northeast portion of Rusk County, Texas, and consist of 50+ leases covering approximately 2100+ net mineral acres in the Dirgin and Oak Hill Fields area," as described in an attached Exhibit "A." Exhibit "A" gave the lessor's name, the survey name, the term, and the net acreage for each lease at issue. Such information is insufficient to identify the exact location of a lease with reasonable certainty, so that the 1978 agreements were unenforceable, the court declared. It offered no explanation beyond the citation of two cases holding that a description of a quantity of

acreage out of a larger tract, without any more specific reference to its location, is insufficient.

The lease descriptions in the 1982 agreements were similar though the circumstances were somewhat more complex. They stated that the leases were “located in the Northcentral portion of Rusk County, Texas, in the North Henderson Field Area, and consist of 143 leases covering approximately 2100 net mineral acres” described in Exhibit “A” thereto, and further that “[a]ll of the acreage as shown on Exhibit ‘A’ (attached) is dedicated to a Gas Contract with Tejas Gas Corporation.” No exhibit was attached to the agreements, but the Griffins placed in evidence the Tejas contract that apparently was the subject of the 1982 agreements’ reference to a gas contract. The Tejas gas contract purported to embrace all leases and lands described on its Exhibit “A” and outlined on its Exhibit “B,” but Exhibit “A” to the gas contract was essentially blank, and Exhibit “B” was merely a plat that identified no leases. Another attachment to the gas contract was entitled “Exhibit A” and did provide a legal description of the pertinent leases, but it stated that it was attached to a letter agreement between the Long Trusts and a third party rather than the Tejas gas contract. The Tejas gas contract, according to the court, only provided confusion, not reasonable certainty, as to the identity of the leases covered by the 1982 agreements.

The court of appeals had held that the Long Trusts could not use the Statute of Frauds to avoid enforcement of the agreements when they had accepted their benefits. Under the terms of the agreements, however, the Griffins had the right to participate or not on a “project by project or well by well basis.” The Griffins’ past acquisitions of leases under the agreements were completely separate from future transactions and did not insulate the agreements from the Statute of Frauds for wells not yet drilled.

The supreme court’s cursory treatment of the issues is disappointing, particularly with respect to the 1978 agreements. As the court noted, to satisfy the Statute of Frauds a contract must furnish within itself, or by reference to some other existing writing, the means or data by which the property to be conveyed may be identified with reasonable certainty. It is unclear why a reference to a lease by lessor name, survey name, term, and net acreage is insufficient to provide the means to identify it if those items apply to a unique lease. The case is not the same, as the court implies it is, as one in which an agreement attempts to identify a tract within a larger survey without identifying its location.

CLAIM TO MINERAL TITLE BY ADVERSE POSSESSION MUST BE BROUGHT AS STATUTORY TRESPASS TO TRY TITLE ACTION

The plaintiffs in *Ruiz v. Stewart Mineral Corp.*, 202 S.W.3d 242 (Tex. App.—Tyler 2006, pet. denied), brought their suit as an action for a declaratory judgment that they owned an undivided one-half mineral interest in several tracts in Nacogdoches and Rusk Counties, Texas. With respect to an undivided one-fourth mineral interest, their claims were based on a 1938 deed. For their title to the remaining one-fourth they relied on adverse possession under Texas’s five-year and ten-year limitation statutes.

A declaratory judgment action may serve as a vehicle for parties seeking a determination of their rights under a deed or contract. On that basis and on the basis that the defendants had not

submitted any evidence raising a fact issue against the validity of the 1938 deed, the court upheld the trial court’s summary judgment for the plaintiffs’ title to the one-fourth claimed under the deed. The court, however, reversed the summary judgment with respect to the other one-fourth, which had been based on adverse possession. Under *Martin v. Amerman*, 133 S.W.3d 262 (Tex. 2004), a trespass to try title action under the Tex. Prop. Code Ann. § 22.001(a), is the exclusive means of resolving a claim of title by adverse possession. A declaratory judgment action was improper with respect to that claim.

LOUISIANA LAW HELD APPLICABLE TO INDEMNITY PROVISIONS OF CONTRACT FOR WELL DRILLED THERE

The dispositive issue in *Cudd Pressure Control, Inc. v. Sonat Exploration Co.*, 202 S.W.3d 901 (Tex. App.—Texarkana 2006, pet. filed), was whether the law of Texas or that of Louisiana governed the rights of the parties to an oilfield master service contract. The case is peculiar in that the parties to the appeal had agreed between themselves that the trial court’s ruling for Texas law would not be appealed. In a case decided by the Texas Supreme Court, *In re Lumbermen’s Mutual Casualty Co.*, 184 S.W.3d 718 (Tex. 2006), however, the contractor’s insurer, which would sustain the loss if the trial court judgment stood, was allowed to intervene and appeal the choice of law issue.

Sonat, the operator of a gas well in Louisiana, hired Cudd to work on the well pursuant to a master service agreement that evidently included detailed indemnity provisions under which each party agreed to indemnify the other against claims for injury or death brought by the indemnifying party’s own employees, regardless of the cause. The well blew out, and four Cudd employees were killed. Sonat settled their claims for a total of more than \$20 million and sought indemnity from Cudd under the contract. At trial the jury determined the amount reasonable, and the court, applying Texas law, rendered a judgment against Cudd for the settlement amount. Cudd appealed on the basis that the court had incorrectly applied certain portions of the Texas oilfield anti-indemnity statute. Louisiana law, if it applied, apparently would preclude Sonat’s recovery under that state’s anti-indemnity statute.

The master service agreement contained no clear choice of law provision applicable to the entire contract, but it included specific indemnity provisions for wells drilled in Louisiana. Applying the *Restatement (Second) of Conflict of Laws* § 196 (1971) and *Maxus Exploration Co. v. Moran Bros., Inc.*, 817 S.W.2d 50 (Tex. 1991), the court held that because the services performable under the contract were to be rendered in Louisiana, and Texas did not have a more significant relationship to the matter because of some other factor, Louisiana law should apply.

Texas had no more significant contacts with the agreement or its subject matter than Louisiana. The place of contracting was indeterminate, and the parties’ places of business were diverse. The policies underlying the law of both states were similar—the restriction of abusive indemnity practices in drilling operations—so that application of Louisiana law could not be said to be contrary to a fundamental policy of Texas.

The court rejected the approach of *Chesapeake Operating, Inc. v. Nabors Drilling USA, Inc.*, 94 S.W.3d 163 (Tex. App.—Houston [14th Dist.] 2002, no pet.), in which the court of appeals

had differentiated between the places of performance of services under the drilling contract at issue there and the performance of its indemnity provisions, found to be the place where the personal injury suit had been prosecuted. In *Chesapeake*, in other words, the drilling was in Louisiana, but the suing was in Texas, justifying the court's application of Texas law. In the *Chesapeake* contract, however, the parties had agreed that Texas law would apply to the entire contract. There was no such provision in the parties' contract here. It included indemnity provisions, moreover, designed to address the peculiarities of the indemnity laws of several states in which services might be performed. These provisions established that indemnity rights were tethered to the state where the well was drilling, and to say the place of performance would instead be the location of an ensuing lawsuit would ignore the contract's plain language. The court here ultimately agreed with the *Chesapeake* majority: it observed that the parties should have what they bargained for.

JURY'S DISCOUNTING OF EXPERT TESTIMONY IN DRAINAGE CASE HELD PROPER

The court in *Vela v. Wagner & Brown, Ltd.*, 203 S.W.3d 37 (Tex. App.—San Antonio 2006, no pet.), decided the appeal by the plaintiff royalty owners in an oil and gas drainage case. Plaintiffs complained that the \$3 million awarded them by the jury (which was negated by prior settlements with other parties, resulting in a take nothing judgment) was inadequate and based on the jury's failure to follow the court's instructions.

In June and November of 1999, Wagner & Brown drilled two wells on its Lopez lease, which adjoined its Cavazos lease under which the plaintiffs were royalty owners, the first of which was drilled to a location less than 100 feet from the Cavazos lease line. Both Lopez wells produced large volumes of gas. Wagner & Brown drilled its first well on the Cavazos lease in March 2000. It eventually drilled one more well on the Lopez lease and four more on the Cavazos lease, as well as one on its Vela lease, also adjoining the other two. The Cavazos royalty owners sued Wagner & Brown, alleging substantial drainage resulting from Wagner & Brown's failure to timely drill wells on the Cavazos lease. In a preliminary ruling the trial court determined that any damages would be calculated using a hypothetical well model for lost royalties, without considering the aggregate expected production from actual wells, by measuring the difference between the royalties that would have been paid on hypothetical wells drilled at the proper time and in the proper locations and the actual royalties paid. The jury was so instructed at the close of testimony and assessed damages from drainage at \$3 million.

The royalty owners' principal complaint on appeal focused on the testimony of Howell, their damages expert, who testified on direct examination that the damages for drainage were \$13.9 million, taking the royalties that would have been paid on the hypothetical wells that should have been drilled on the Cavazos lease and subtracting the royalty paid on the actual Cavazos wells. He admitted on cross-examination that his assumed flow rate for the hypothetical Cavazos wells was overstated by 15% based on the performance of the actual Cavazos wells, which would, according to Wagner & Brown's expert, have reduced the damages under Howell's model to \$9.4 million. In response to another question on cross-examination, stemming from his finding that total

production from two hypothetical wells on the Lopez lease would have recovered 2.4 bcf of gas less than the two actual Lopez wells, Howell also testified that the 2.4 bcf difference "most likely" would have been produced from the Cavazos lease and that he did not necessarily disagree that this could be the amount of drainage from the Cavazos lease. Wagner & Brown's own expert, Garza, testified that under Howell's model the maximum amount that could have been drained off the Cavazos lease onto the Lopez lease was 2.4 bcf and that this was worth \$3 million net to the plaintiffs. On appeal the plaintiffs argued that it was clear that the jury had not followed the trial court's instructions and had impermissibly assessed damages based on the amount drained away by actual production, using the damage model the trial court had rejected.

Unless the record clearly demonstrated otherwise, the court of appeals observed, it must presume that the jury followed the court's instructions on damages. There being no direct evidence of jury misconduct, the real question was whether the \$3 million damages award had a rational basis and fell within the range of evidence presented at trial. The court rejected the plaintiffs' argument that the jury was bound to accept one of only two options: to award either the \$13.9 million to which Howell had testified or the \$9.4 million that would represent a reduction for his overstated flow rate. Limiting the jury award to that range, said the court, would ignore the jury's role in judging the credibility and weight of competing expert evidence. The damages evidence presented at trial ranged from none at all, based on Garza's testimony that no substantial drainage in fact occurred, to the \$13.9 million figure to which Howell testified. Garza testified without objection that Howell's own model, designed with the court's hypothetical-well formula in mind, at most revealed only 2.4 bcf of drainage. Other testimony questioned other aspects of the Howell model, including his assumptions about the timing and location of wells a prudent operator would have drilled and the underlying geology. The jury was not required to unquestioningly accept Howell's damages model, but was entitled to make credibility determinations and weigh the competing expert testimony about Howell's model and the variables and assumptions on which it was based. The jury could reasonably have reached its \$3 million award, the court held, by making further reductions to Howell's \$9.4 million figure based on the various flaws pointed out by Garza and other experts, even without relying on Garza's testimony of the \$3 million value of 2.4 bcf of drainage.

LANDMAN HELD LIABLE FOR ABETTING LAWYER'S FRAUDULENT MINERAL SALES

The court in *Robertson v. ADJ Partnership, Ltd.*, 204 S.W.3d 484 (Tex. App.—Beaumont 2006, pet. filed), decided the appeal by Robertson, a petroleum landman, and his corporation, Sibling A, Inc., of a judgment against them for participation in a scheme to defraud ADJ Partnership, Ltd. and Virginia Henderson Adams. The court's opinion focused on the conduct of Robertson's co-defendant, lawyer Bill McGraw, who had settled and was not a party to the appeal.

Adams was McGraw's wife's sister, and Adams and the McGraws were cotenants in various oil and gas leasehold and mineral properties, including those involved in the transactions at issue in this case. McGraw had regularly done legal work for Adams and

other members of his wife's family, the Hendersons, even up until the time the suit was filed, and he and his wife, Adams, and ADJ were all partners in the family business, the Henderson Family Partnership. Robertson, the landman, had known McGraw for a number of years and also knew Adams and had leased minerals from her in the past.

After discussing with Adams the idea of generating income from their inactive jointly owned properties and securing her agreement to specified terms, McGraw approached Robertson for assistance. The court detailed some seven transactions that ensued, the common feature of which was that Adams would convey or lease her interests to Sibling A, a corporation evidently wholly owned by Robertson but whose public documentation did not disclose his association with it. Sibling A, whose president was McGraw, would then sell to a third party and share the proceeds with McGraw.

The court found that the evidence supported the trial court judgment against Robertson and Sibling A for abetting McGraw's breach of his fiduciary duty to Adams and ADJ and for fraud. Responding to the argument that McGraw had no fiduciary relationship to the plaintiffs, the court noted that McGraw had maintained a long-term formal fiduciary relationship with members of the Henderson family by virtue of his having acted as their attorney. Moreover, the jury could reasonably conclude that an informal fiduciary duty, based on a special relationship of trust and confidence, arose from the close family relationship and the family's history of joint business pursuits. McGraw had taken pains in the past to stress that he was looking after the family properties for the benefit of all and had hidden the fact that he was receiving more from the dealings with Robertson than Adams was.

The evidence, the court concluded, also supported the jury's findings that Robertson and Sibling A aided and abetted McGraw and had themselves committed fraud. Robertson admitted that he structured the transactions and knew the family and that McGraw was being paid more than Adams. The jury was entitled to reject his explanation that he had shared proceeds with McGraw merely because McGraw had included him in some unspecified past deals and instead conclude that Robertson shared his profits with McGraw in return for McGraw's deceiving Adams into assigning her interests. Robertson and Sibling A did not challenge the jury's finding that McGraw had committed fraud, and Texas law, the court observed, holds each party to a fraudulent scheme responsible for the acts of the other participants.

DAMAGE AWARD FOR LOST PROFITS ON FIELD DEVELOPMENT REVERSED AS SPECULATIVE

Ramco Oil & Gas Ltd. v. Anglo-Dutch (Tenge) L.L.C., 207 S.W.3d 801 (Tex. App.—Houston [14th Dist.] 2006, pet. filed), decided the appeal by Ramco Oil & Gas Ltd. and Ramco Energy PLC, two affiliated Scottish concerns, of a \$6.4 million judgment for their breach of a confidentiality agreement.

Scott Van Dyke and companies affiliated with him, the plaintiffs, had been trying since 1992 to realize Van Dyke's "dream and business plan" of developing the Tenge oil and gas field in Kazakhstan. He gathered several groups of investors that together formed a limited liability company, Anglo-Dutch (Kazakhstan) L.L.C. (Kazakhstan), which acquired a 25-year right to develop the field as a joint enterprise with an affiliate of the Kazakh gov-

ernment. In 1997 Ramco Energy signed a confidentiality agreement with a member of Kazakhtenge in order to examine the possibility of involvement in development of the Tenge Field. Three months later Ramco Oil & Gas and Halliburton Energy Services, Inc. adopted the same confidentiality agreement as part of a letter of intent executed with another Van Dyke affiliate. Ramco Oil and Halliburton retained as a consultant Golden Eagle Partners, which had experience in communications and relations with the government of Kazakhstan.

The Ramco entities and Halliburton decided not to pursue the Tenge Field development. Then, in 2000, Golden Eagle joined with another company, Central Asia Industrial Investments, N.V., in acquiring the rights of Kazakhtenge through negotiations with Van Dyke's investors. The Van Dyke companies sued Halliburton and the affiliated Ramco entities, alleging they had breached the confidentiality agreement by disclosing information to Golden Eagle, which disclosure had resulted in Central Asia's acquiring Kazakhtenge's rights. But for these breaches, they claimed, the plaintiffs would instead have acquired the Kazakhtenge members' interests, developed the Tenge Field, and earned \$640 million in profits by the end of the term of the development agreement. After a six-week trial, the jury rendered judgments awarding the plaintiffs \$64 million against Halliburton and \$6.4 million against the Ramco parties. Halliburton settled, but Ramco pursued this appeal.

The plaintiffs' evidence of their damages consisted primarily of the testimony of two experts, George Schaefer, a petroleum engineer, and John Brickhill, an economic analyst. Schaefer projected the future production from the Tenge Field based on data provided by the plaintiffs, and Brickhill used that information to project the resulting profits. Brickhill's projections were based further on the assumption that the plaintiffs would be able to obtain financing for the acquisition of the existing investors' interests, persuade them all to sell to Van Dyke, finance the initial development of the field, and achieve enough success to finance the remaining development. In the factual context reflected by the trial record, the court held, it was speculative to have made any such assumptions, particularly given that Van Dyke had a strained relationship with the existing investors and had no commitment for new financing. Moreover, although Schaefer testified he was "pretty certain" of his projections, they were based not on actual production history but just on test data. The lack of production data rendered speculative both the amount of future production, and thus lost profits, and the likelihood of attracting financing.

Lost profits must be ascertainable with a reasonable degree of certainty, the court observed. Here, to realize Van Dyke's objective, the plaintiffs would have needed to obtain their investors' approval. Then, despite the lack of profitable past production, they would have had to convince a third-party lender to put millions of dollars at risk without giving up equity. Their proof of lost profits was, the court held, largely speculative, dependent on uncertain and changing market conditions, and based on risky business opportunities and the success of an unproven enterprise. Despite the expert witnesses' fervent hopes of success, their testimony was insufficient to prove with reasonable certainty what profits the plaintiffs lost as a result of any breaches, and the trial court had erred in rendering judgment for them.

RAILROAD COMMISSION HAS AUTHORITY TO REVIEW GAS UTILITY'S PAST GAS PURCHASES AND ORDER CUSTOMER REIMBURSEMENT

CenterPoint Energy Entex, a gas utility subject to the Texas Gas Utility Regulatory Act (GURA), purchased gas on behalf of customers served by the Tyler Integrated Distribution System and charged rates approved by the City of Tyler. The rate schedules included a Produced Gas Adjustment (PGA) provision, under which Entex was allowed to pass through increases in the cost of gas in its charges to customers. In 2002 the city began reviewing the manner in which Entex had allocated the cost of gas purchased from two different suppliers, one at a significantly higher price than the other, between large commercial customers and small and residential customers. The city ultimately alleged Entex's procedures had resulted in overcharges of some \$39 million to small customers. Entex and the city agreed to submit their dispute over the alleged overcharges to the Texas Railroad Commission but disagreed about what the Commission's review should entail. Entex asserted that the Railroad Commission has power only to determine whether it had properly charged and collected for gas sales to residential and commercial customers but could not consider the prudence of Entex's gas purchases because that would constitute retroactive ratemaking. The city argued that the Commission should conduct a retroactive prudence review of Entex's gas purchases. The court in *CenterPoint Energy Entex v. Railroad Commission*, 208 S.W.3d 608 (Tex. App.—Austin 2006, pet. filed), upheld the Railroad Commission's determination that it did have the power to conduct retroactive prudence reviews.

The GURA, the court noted, charges the Railroad Commission with ensuring compliance with the obligations of gas utilities, including the power to conduct examinations and audits. A PGA clause such as the one made a part of Entex's rate schedule makes the amount charged to customers dependent on the price of gas purchased. The customer is harmed by PGA clauses only if they are manipulated and abused, and criticisms of them are met if the regulatory body reviews charges recouped through a PGA clause and determines that they were just and reasonable. A necessary corollary to such review is the power to take corrective action when the utility has misapplied the terms of its rates. In other words, said the court, an allegation that a utility has manipulated its purchases to artificially raise the cost of fuel differs in no substantial way from the claim that a utility charged customers a price greater than an approved fixed rate. Thus, the Commission must have the power to review past gas purchases and order refunds as part of its express power to ensure compliance with the approved rate. Otherwise, the Commission's authority would be reduced to the ministerial task of verifying the utility's arithmetic. This power, although it may have retroactive effect, is not prohibited retroactive ratemaking. The Commission's assertion of authority is not an attempt to disturb the determination that rates are just and reasonable but will only concern application of the approved rates.

WYOMING — OIL & GAS

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— REPORTER —

ROYALTIES AND TAXES ARE NOT PART OF "DIRECT COSTS" IN CALCULATING TAXABLE VALUE OF OIL AND GAS PRODUCTION UNDER WYOMING'S PROPORTIONATE PROFITS FORMULA

In *RME Petroleum Co. v. Wyoming Department of Revenue*, 2007 WY 16, 150 P.3d 673 (Wyo. 2007), the Wyoming Supreme Court considered three consolidated appeals from taxpayers whose tax valuations for oil and gas production were determined under the proportionate profits method allowed under Wyo. Stat. Ann. § 39-14-203(b)(vi)(D). At issue in all three cases was whether royalties and production taxes must be treated as "direct costs of producing" under the proportionate profits formula, one of the four valuation methods allowed for oil and gas production. Under that formula, including royalties and production taxes as "direct costs" results in a higher valuation and higher taxes.

In an earlier administrative appeal, *In re Appeal of Amoco Production Co.*, No. 96-216, 2001 WL 1150220 (Bd. of Equalization, Wyo. Sept. 24, 2001) (*Amoco 96-216*), the Department of Revenue (Department) and Amoco Production had both agreed that royalties and production taxes should not be considered as direct costs in applying the proportionate profits formula. In that case, Unita County was allowed to intervene and took the opposite view. The Board of Equalization (Board) found contrary to the position of the Department and Amoco and held that production taxes and royalties are direct costs under the statute in question. The board's decision in *Amoco 96-216* was appealed to the Wyoming Supreme Court, which held that the county should not have been allowed to intervene. Consequently, the supreme court vacated the board's decision without specifying how royalties and production taxes should be treated under the proportionate profits formula. Although *Amoco 96-216* was vacated, the Department thereafter administered Wyo. Stat. Ann. § 39-14-203(b)(vi)(D) in accordance with the board's decision.

Soon after enactment of Wyo. Stat. Ann. § 39-14-203(b)(vi)(D), the Department of Revenue adopted Chapter 6, Rule 4b defining "direct costs of production." Rule 4b does not mention royalties or production taxes. Although Rule 4b has never been changed, the Department changed its treatment of production taxes and royalties to include them as "direct costs" following the supreme court's vacation of the holding in *Amoco 96-216*.

In this case the supreme court found Wyo. Stat. Ann. § 39-14-203(b)(vi)(D) to be ambiguous and looked to Rule 4b for clarification of the Department's position as to the application of the statute. The court noted that the Department's position on application of the statute had changed over time and attributed more weight to the earlier position—that royalties and production taxes were not properly included in direct costs under the proportionate profits formula. More importantly, the court found the Department's current application of Rule 4b to be contrary to the plain language of the statute. The court stated that Rule 4b does not include "production taxes" or royalties in the list of includable costs.

The supreme court overlooked the fact that “ad valorem taxes on production” are mentioned in the rule and are one type of production tax, but nevertheless held that the omission of production taxes and royalties was deliberate and that Rule 4b was not ambiguous. The court resolved the ambiguity in the statute by interpreting it consistently with the language of the Department’s rule interpreting it. The court held that production taxes and royalties are not included as direct costs under the proportionate profits formula of Wyo. Stat. Ann. § 39-14-203(b)(vi)(D).

CANADA — MINING

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BC SUPREME COURT RESTRICTS DUTY TO CONSULT WITH FIRST NATIONS TO CONSULTATION WITH ELECTED REPRESENTATIVES

Recent Canadian court decisions have established that there is a duty held by the federal and provincial governments to consult with First Nations. The Supreme Court of British Columbia’s decision in *Red Chris Development Co. v. Quock*, 2006 BCSC 1472, provides direction for project proponents regarding the identification of the appropriate aboriginal groups with which to consult, and also shows that where there has been good faith consultation, the courts are unlikely to grant immediate enforcement orders stopping blockading of public roads.

In the case, *Red Chris Development Co. Ltd.*, a subsidiary of bcMetals Corporation, sought an injunction to restrain blockade by members of the Iskut First Nation of a public road used to transport exploration equipment. The Red Chris Project had already obtained an Environmental Assessment Certificate, a regulatory process that included extensive consultation with the Tahltan and Iskut First Nations as well as rigorous environmental review.

Members of the Iskut First Nation argued that consultation with elected representatives was not sufficient to satisfy the duty to consult and that, in addition, local users of the land should be consulted. If the court had accepted this position, those granting permits for development in areas in which there exist land claims could have been required to consult with First Nations down to the individual level (e.g., all persons using the lands that may be affected should be consulted). Instead, the decision clarifies that this is not required and that consultation must take place with elected representatives.

B.C. SUPREME COURT COMMENTS ON FIDUCIARY OBLIGATIONS IN NEGOTIATION OF JOINT VENTURE AGREEMENT WHEN A CONFIDENTIALITY AGREEMENT IS IN PLACE

In *Novawest Resources Inc. v. Anglo American Exploration (Canada) Ltd.*, 2006 BCSC 769, the British Columbia Supreme Court considered fiduciary obligations in the context of the nego-

tiation of a joint venture agreement when a confidentiality agreement is in place.

In the case, the plaintiff Novawest Resources Inc. (NRI) alleged that the defendant Anglo American Exploration (Canada) Ltd. (AA) staked mineral claims in an area of northern Quebec in breach of a common law duty of confidentiality. The plaintiff alleged that AA owed it this duty as a result of a disclosure of information at meetings held between the parties while they discussed jointly pursuing further exploration of mineral claims NRI had staked in northern Quebec. In order to pursue the joint venture, NRI had to disclose confidential information to AA about these claims. The information was protected by a confidentiality agreement between the parties. Counsel for NRI placed considerable reliance on the decision of the Supreme Court of Canada in *Lac Minerals Ltd. v. International Corona Resources Ltd.* [1989] 2 S.C.R. 574, in which there was no such agreement between the parties.

Mr. Justice Edwards quoted *Lac*, “When the parties have reduced their understandings to writing, it is obviously the proper course for courts to be extremely circumspect in adding to the bargain they have set down,” and held that, in order to succeed in this case, NRI needed to demonstrate that AA based its decision to stake its Quebec claims on the confidential information it obtained from NRI, and that AA was under a legal duty at common law not to use such confidential information when it staked those claims. In determining the answer to this question, the court undertook an analysis of the terms of the confidentiality agreement to determine whether it expressly permitted AA to use the confidential information to stake outside the area of influence defined in the confidentiality agreement (all claims staked by AA were outside the area of influence).

The court found that to have any practical effect the confidentiality agreement must permit AA to receive confidential information, without the risk that receiving it would preclude AA from staking outside the area of influence if no option or joint venture agreement was concluded by the parties. Part of the basis for this was that the commercial purpose of the confidentiality agreement was to avoid disputes about which party had what information and what information could be used in deciding to stake outside the area of influence.

The confidentiality agreement supplanted any common law duty of confidentiality AA owed the plaintiff with respect to land outside the area of influence. As the claims staked by AA were all outside the area of influence AA acted in conformity with the confidentiality agreement and was not in breach of a common law duty of confidentiality.

The decision in *Novawest Resources* further underscores the importance of careful drafting of confidentiality agreements such as the one in this case.

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