

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the complaint of)
DOMINION MIDWEST ENERGY, INC.,)
DOMINION RESERVES, INC., MILLER ENERGY,)
INC., MUSKEGON DEVELOPMENT COMPANY,)
and **QUICKSILVER RESOURCES, INC.,** against)
MICHIGAN CONSOLIDATED GAS COMPANY,)
MICHCON GATHERING COMPANY, and)
MICHCON PIPELINE COMPANY.)
_____)

Case No. U-12342

At the July 11, 2001 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Laura Chappelle, Chairman
Hon. David A. Svanda, Commissioner
Hon. Robert B. Nelson, Commissioner

OPINION AND ORDER

History of Proceedings

On March 6, 2000, Dominion Midwest Energy, Inc., Dominion Reserves, Inc., Miller Energy, Inc., Muskegon Development Company, and Quicksilver Resources, Inc., filed a complaint against Michigan Consolidated Gas Company (Mich Con), MichCon Gathering Company, and MichCon Pipeline Company. The complaint seeks prospective and retroactive relief from the rate of 9¢ per thousand cubic feet (Mcf) that MichCon Gathering now charges for providing transportation service with the Antrim Expansion Project (AEP) facilities, as authorized in the March 29 and September 7, 1995 orders in Case No. U-10547. The complainants are producers of natural gas

from wells drilled in Antrim shale formations in the northern lower peninsula. Mich Con constructed the AEP to provide transportation access for the Antrim production to downstream markets in Michigan.

On April 3, 2000, the respondents filed an answer with a motion to dismiss those allegations of the complaint that they argued would be retroactive ratemaking.

On May 11, 2000, Administrative Law Judge James N. Rigas (ALJ) conducted a prehearing conference and granted leave to intervene to Shell Western E & P Inc. (SWEPI). The Commission Staff (Staff) also appeared and participated.

On May 25, 2000, the ALJ conducted a hearing on the respondents' motion to dismiss. At the conclusion of the hearing, the ALJ orally issued a partial Proposal for Decision (partial PFD), in which he struck portions of the complaint that requested that the Commission order a refund of prior overcollections or apply the overcollections to reduce the revenue requirement prospectively. The ALJ stated that those claims would be retroactive ratemaking. Tr. 69-76. On June 21, 2000, the complainants and the respondents filed exceptions to the partial PFD, and the same parties and the Staff filed replies to exceptions on June 30, 2000.

The ALJ conducted evidentiary hearings relating to prospective rate relief on November 7 through 9, 2000. The complainants, the respondents, and the Staff presented testimony. The ALJ also accepted the parties' stipulation regarding the AEP's cost of capital, which avoided the presentation of testimony addressing that issue. Tr. 84-86. With revisions adopted during the hearings, the complainants proposed a prospective AEP transportation rate of 2.2¢ per Mcf, the respondents proposed 8¢ per Mcf, and the Staff proposed \$0.04835 per Mcf. Respondents' initial brief, App. A. Thereafter, the parties filed briefs and reply briefs.

On February 23, 2001, the ALJ issued a written final Proposal for Decision (final PFD) recommending a transportation rate of \$0.05856 per Mcf. On March 9, 2001, the complainants and the respondents filed exceptions to the final PFD. On March 19, 2001, all parties filed replies to exceptions.

Factual Background

The issues in this case deal primarily with the AEP's cost of service. Placing those issues in a proper context requires some understanding of the reasons for constructing the AEP, which arose out of capacity and operational constraints of Mich Con's preexisting Wet Header facilities. Prior to the AEP, Mich Con had been using the Wet Header to transport, not only the increasing amounts of Antrim production, but also gas from previously developed Niagaran and other formations. The March 29, 1995 order in Case No. U-10547 provides a contemporaneous description of the emergence of Antrim production and the decision to construct the AEP:

Mich Con currently owns and operates a complex system of gas transmission pipelines and related facilities in Michigan. One of its pipelines is the Wet Header Pipeline (Wet Header), through which Mich Con transports gas produced from various gas-bearing underground formations, including a Devonian age shale formation that underlies much of northern Michigan and takes its name from an outcropping in Antrim County. Numerous pipelines and assorted laterals currently feed Antrim gas into the Wet Header.

The Wet Header, which was constructed by Mich Con pursuant to the Commission's October 22, 1971 order in Cases Nos. U-3933 and U-3935, extends approximately 191 miles across Michigan's northern lower peninsula. Originally, it carried gas that was frequently saturated with liquid hydrocarbons, such as propane, butane, and pentane. Accordingly, contemporaneous with the construction of the Wet Header, SWEPI and Amoco¹ built processing plants near Kalkaska to remove liquids from the gas carried on the Wet Header.

¹Amoco's interest was eventually transferred to SWEPI.

In 1988, pursuant to the November 12, 1987 order in Case No. U-8616, the Wet Header was opened to transporters other than Mich Con and Consumers [Power Company, now Consumers Energy Company]. The Wet Header became the leading means of moving Antrim gas to market due to its location, capacity, and reasonable transportation rates.

Due in large part to the availability of tax credits, the number of Antrim gas wells has increased to a point where the production of Antrim gas is constrained by the lack of available capacity on existing pipelines to deliver additional gas to downstream customers without curtailments, which causes gas to be “shut-in.”⁴

The introduction of large volumes of Antrim gas also caused an operational concern. Antrim gas contains relatively high concentrations of carbon dioxide (CO₂), ranging from 6% to 12% by volume, but almost no natural gas liquids. In the presence of water, high levels of CO₂ may lead to the creation of carbonic acid, which can damage pipelines and storage field wells and piping.

When Antrim gas was first introduced into the Wet Header, the overall concentration of CO₂ in the pipeline was minimal because the small amount of Antrim gas was substantially diluted by the much larger volumes of non-Antrim gas. However, as non-Antrim wells began to deplete and as more Antrim wells came on-line, concerns developed regarding the potential for corrosion caused by high CO₂ levels.⁵

⁴Being “shut-in” means that, despite the fact that a well has been drilled and is capable of producing gas, the producer has no way to transport this gas to market. Shutting in a well may result in a deterioration of its future production capability.

⁵Nearly all interstate pipeline systems require a CO₂ concentration of 2% or less. By the end of 1989, the CO₂ concentration on the Wet Header had surpassed that threshold.

Order dated March 29, 1995, Case No. U-10547, at 3-5 & nn.4-5 (other footnote omitted).

As authorized in Case No. U-10547, Mich Con constructed the AEP to provide a parallel transportation system for Antrim gas. The AEP facilities have three major components: (1) the 10 inch outer diameter (O.D.) North Charlton Pipeline, which is 8.6 miles long and terminates at South Chester, (2) the 16 inch O.D. Kalkaska Tie Line, which runs 44.7 miles from South Chester

to Kalkaska, parallel to the eastern segment of the 20 inch O.D. pipeline then known as the Wet Header (or Eastern Wet Header to distinguish it from the Wet Header segment approaching Kalkaska from the other direction), and (3) the 30 inch O.D., 11 mile Kalkaska Woolfolk Loop downstream from Kalkaska, which duplicates part of a 30 inch Mich Con pipeline proceeding from the outlet of the SWEPI Kalkaska Processing Plant. As provided in the AEP design, Antrim gas would undergo treatment to remove CO₂ at plants located at South Chester, before being delivered to the Header connecting South Chester with Kalkaska.

Before the AEP facilities became operational in November 1995, Mich Con transferred them to its newly formed subsidiary, MichCon Gathering. However, MichCon Gathering does not have any employees, and Mich Con personnel actually conduct AEP operations.

It is a somewhat curious feature of the development of the Header system that the primary use of the AEP's main component, the 16 inch Kalkaska Tie Line, is not to transport Antrim gas. Anticipating larger flows of Antrim gas that requires CO₂ removal at South Chester, Mich Con converted the 20 inch Eastern Wet Header into the Dry Header and used the 16 inch Tie Line, now known as the Wet Header, as the primary pipeline for declining volumes of Niagaran production. Because dry Antrim gas does not require treatment to remove liquids, the converted 20 inch pipeline was disconnected from the inlet of the Kalkaska Processing Plant and bypassed it. However, a small amount of Antrim gas continues to flow commingled with wet gas on the 16 inch Wet Header, and some non-Antrim wet gas also flows on the 20 inch Dry Header. To a large extent, this can be largely explained by the limitations of a preexisting gathering system that "traps" both Antrim and Niagaran production onto laterals tied to only one of the Headers. However, the respondents have also blended Antrim gas on the 16 inch Wet Header to relieve capacity constraints on the 20 inch Dry Header.

Even though it does not hold title to the Wet Header, Mich Con provides the transportation service for non-Antrim gas and collects the Wet Header tariff rates. MichCon Gathering, which owns the Wet Header, provides transportation for Antrim gas at the approved AEP contract rate of 9¢ per Mcf. This relationship between the two affiliates applies regardless of which route or pipeline the gas actually travels. Moreover, the cost of service for Antrim transportation in both Case No. U-10547 and this case includes the cost of the 16 inch Wet Header as part of the AEP and excludes the cost of the older 20 inch Dry Header. The apparent rationale is that the cost of service recovered by the AEP rate is computed as an increment to the cost of providing transportation service for non-Antrim gas over preexisting Mich Con facilities. By the time of the decision to construct a second Header for Antrim gas, shippers of non-Antrim gas were benefitting from relatively low transportation rates recovering the costs of a mostly depreciated pipeline that was more than 20 years old. To preserve the non-Antrim shippers' interests in maintaining their access to low-cost transportation, it was understood that the operation of the AEP would not shift costs to, or otherwise adversely affect, the Wet Header rate.

The March 29, 1995 order in Case No. U-10547 withheld initial authorization for the Kalkaska Woolfolk Loop and approved an AEP rate of 7½¢ per Mcf, with a conditional 1½¢ increase to recover the costs of the Kalkaska Woolfolk Loop if it were to be approved later. An order issued on September 7, 1995 in Case No. U-10547 granted the additional authorization for the Loop and increased the AEP rate to 9¢ per Mcf.

The methodology used to compute the rate in Case No. U-10547 assumed a levelized recovery of costs over the first ten years of the AEP's operation. It adopted projections of the AEP's volumetric throughput and cost of service for the ten-year period to calculate a fixed rate that would produce, in present value terms, revenues equal to the costs over the entire period. The

parties have generally concurred in the levelized rate methodology for purposes of this case, but they are using only the last five years of the original ten-year period.

Retroactive Relief

The first round of exceptions that the parties filed on June 21, 2000 addresses the ALJ's ruling in the partial PFD that dealt with the issue of retroactive rate relief.

The complainants assert that the AEP transportation rate of 9¢ per Mcf established in Case No. U-10547 has proven to be excessive, producing overearnings of at least \$21 million during the first five years of the AEP's operation. The complainants ask that the overearnings either be refunded to them or used to reduce rates prospectively. They deny that either approach would be a form of the retroactive ratemaking that the Court prohibited in Michigan Bell Telephone Co v Public Service Commission, 315 Mich 533; 24 NW2d 200 (1946).

The complainants argue that the Michigan Bell decision acknowledges that the prohibition against retroactive ratemaking does not apply when a statute provides express authority for a retroactive rate adjustment or authorizes the adjustment by necessary implication. The complainants say that a transportation rate for an intrastate pipeline is subject to Public Act 9 of 1929, as amended, MCL 483.101 et seq.; MSA 22.1311 et seq., (Act 9) and that Section 10 of Act 9, MCL 483.110; MSA 22.1320, expressly requires a rate to be reasonable in order to be lawful. Therefore, they continue, Act 9 by implication requires the Commission to redress an unreasonable rate with a refund. They say that reasonableness must be determined with reference to the cost of service and that the AEP rate was never reasonable because various assumptions used to compute it in Case No. U-10547 were not valid. In other words, they claim, MichCon Gathering chose not to incur some of the costs projected in the rate, so that the AEP generated profits far in excess of

the authorized rate of return. The complainants further distinguish Michigan Bell on the ground that the case did not arise under Act 9.

The complainants characterize the orders in Case No. U-10547 as a non-final decision that authorized an interim rate subject to true-up for actual costs. They say that the rate methodology in Case No. U-10547 used a levelized ten-year period to recover the projected cost of service, but that the AEP's first four years of operation produced revenues that, in present value terms, recovered the entire ten years' cost of service. They say that levelized ratemaking necessitates a true-up. They contend that their position is analogous to deferred cost accounting, which permits the amortization of a past extraordinary expenditure over a future period. They argue that fairness and equity justify an exception to the retroactive ratemaking doctrine.

In reply, the respondents contend that the rule against retroactive ratemaking, as set forth in Michigan Bell, is a well established principle of law and is fully applicable to Act 9, which does not contain any provisions that would authorize an exception. They say that the Commission approved the current AEP rate of 9¢ per Mcf as lawful and reasonable in Case No. U-10547 and that no one appealed the orders, which became final. They state that reliance on projections is an inherent part of ratemaking, that actual revenues and costs can vary from those projected at any given point in time, and that the doctrine of retroactive ratemaking forecloses retroactive adjustments in exactly those circumstances. They argue that there is no basis in Michigan law to carve out exceptions based on equitable circumstances. They dismiss the complainants' analogy to the amortization of extraordinary expenditures by noting that the Commission must grant advance authorization to use deferred cost accounting.

The decision in Michigan Bell states that the Commission may exercise "only such power relative to fixing the rates or earnings of the telephone company as are by statute expressly or by

necessary implication vested in it.” 315 Mich 547. Thus, the rule prohibiting retroactive ratemaking “is grounded on [the Court’s] interpretation of the Commission’s statutory ratemaking authority” and is a corollary of the principle that an administrative agency’s authority to take an action must find its source in a legislative enactment. Order dated December 4, 2000, Cases Nos. U-10138 and U-11743, at 11. The Court in Michigan Bell held that the Commission did not have “either express or implied statutory power to retroactively reduce” the rates of a telephone utility under Public Act 3 of 1939 (Act 3) as it then existed.² 315 Mich 547.

The complainants’ claim that Act 9 authorizes a retroactive rate adjustment is incorrect. Nothing in Act 9 provides express authority or contains words that might confer retroactive authority by implication. Although the complainants rely on the provision in Section 10 that rates must be reasonable,³ authority to set reasonable rates on a prospective basis does not mean that the Commission may make adjustments for past over- or underrecoveries based on actual costs determined with hindsight. The Court in Michigan Bell noted that the telephone rates at issue were subject to the reasonableness standard set forth in MCL 462.22(a); MSA 22.41(a), but it did not equate the reasonableness standard with authority to make retroactive rate adjustments.

Moreover, the Commission’s longstanding interpretation of Act 9, going back at least to the January 18, 1969 order in Case No. U-2895, reaffirms that retroactive ratemaking is not permissi-

²MCL 460.1 et seq.; MSA 22.13(1) et seq. As currently amended, Act 3 excludes telephone providers, which are subject instead to the Michigan Telecommunications Act, MCL 484.2101 et seq.; MSA 22.1469(101) et seq.

³Section 10 does not contain the word “reasonable,” but it cross-references Public Act 106 of 1909, as amended, MCL 460.551 et seq.; MSA 22.151 et seq., which provides for the regulation of electricity transmission and distribution and requires electric rates to be just and reasonable, MCL 460.557; MSA 22.157. See Antrim Resources v Public Service Comm, 179 Mich App 603, 612-14; 446 NW2d 515 (1989).

ble. A concise summary of that order appears in the October 25, 1995 order in Case No. U-10546, at 26:

The Commission's order in Case No. U-2895 also addressed another significant issue. . . . Citing Michigan Bell Telephone Company v Public Service Commission, 315 Mich 533; 24 NW2d 200 (1946), and General Telephone Company v Public Service Commission, 341 Mich 620; 67 NW2d 882 (1954), the Commission held that "in the absence of a specific legislative mandate authorizing retroactive relief, no such authority exists." Order, Case No. U-2895, supra, p. 14. Finding that Act 9 does not authorize the Commission to grant retroactive relief, the Commission concluded that the price reduction requested by the common purchaser could be granted only on a prospective basis.

Although the complainants in this case suggest that a price redetermination for gas received by common purchasers is distinguishable from a pipeline rate case, the text of Act 9 does not support this distinction. The same provisions of Section 10 govern both situations.

In the absence of statutory authority for making a retroactive adjustment under Act 9, the complainants' contention that the orders in Case No. U-10547 set an interim rate subject to true-up also fails. Moreover, the complainants have mischaracterized those orders. Using a levelized rate to recover projected costs over a ten-year period does not require a true-up any more than other rate methodologies that rely on projections of costs and revenues. Nothing in the orders in Case No. U-10547 anticipates a true-up or indicates that the approved rate was meant to be something other than final. Therefore, the Commission finds that the ruling in the partial PFD rejecting those parts of the complaint requesting a retroactive rate adjustment was correct.

In their exception, the respondents argue that the ALJ should have granted a motion to strike excerpts of the complainants' prefiled testimony and exhibits that discuss past financial data or otherwise relate to retroactive ratemaking. Because the record has been completed with the disputed evidence admitted, the matter is moot. Moreover, the Commission agrees with the ALJ

that historical experience can be helpful in providing a factual context for making prospective rate determinations.

Projected AEP Throughput

Developing a forecast of the AEP's throughput is necessary to provide a volumetric basis for computing a transportation rate. The throughput forecast also affects depreciation expense and accumulated depreciation under the unit of production method of depreciation used in both Case No. U-10547 and this case. A working assumption of the AEP forecast is that all of the Antrim reserves capable of being produced on economical terms will flow to market via the AEP, so that the throughput is a function of the Antrim reserves in the area served by the AEP.

The complainants and respondents each presented their own forecasts, which differ as follows for years 2001-05, the last five years of the AEP's ten-year levelized rate period:⁴

	<u>Throughput in million cubic feet (MMcf) per day</u>				
	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>
Complainants	334.3	303.6	277.2	253.7	234.6
Respondents	329.6	300.3	274.1	250.5	229.2

Exs. C-37, R-168. Over the five-year period, the complainants' forecast exceeds the respondents' by about 7 billion cubic feet (Bcf) of Antrim production, and, for an extended period running through the end of 2020, the difference increases to 177 Bcf. Ex. C-37.

The apparent reason for the differences was the methodology used in developing the forecasts. The complainants relied on the SHALEGAS™ computerized model developed by Holditch-Reservoir Technologies (H-RT), a division of Schlumberger Technology Corporation. An H-RT

⁴Although the AEP began operating in November of 1995, a simplifying assumption used in this case is that the last five years of the ten-year period are the calendar years 2001-05.

employee, Joseph Howard Frantz, Jr., testified that the model simulates the properties of shale reservoirs, including Antrim formations. A central premise of Mr. Frantz's analysis is that the trend of production of a shale project ordinarily follows a hyperbolic curve. In other words, a graph of the project would show that after reaching the peak output in relatively short order, the rate of production follows a gradual curve with a low, decreasing rate of decline over a number of years. Mr. Frantz developed individual forecasts for each Antrim project (which typically groups 10 to 20 wells) before cumulating the outcomes of about 300 projects as his AEP forecast.

Frederick W. Metzger, Mich Con's Manager, Reservoir Engineering and Geology, testified that the exponential decline method should be used to forecast Antrim production. This method uses historical production data as a basis for extrapolating a future rate of production as a declining straight line when plotted on a semi-log graph, i.e., the rate at which production declines is constant. In contrast to a hyperbolic curve, an exponential decline implies a higher rate of decline and a shorter productive life. Mr. Frantz and Mr. Metzger agreed that Antrim projects can exhibit exponential rates of decline immediately after reaching their peak output, but they differed regarding whether the exponential decline continues throughout the later years of the project.

Mr. Metzger developed individual forecasts for each of the eight laterals flowing into the AEP. As an economic constraint on the forecast, Mr. Metzger assumed that the production served by each lateral would terminate when the production fell below 20 Mcf per well per day or 5,000 Mcf per lateral per day. On behalf of the complainants, Mr. Frantz adopted a cutoff similar to Mr. Metzger's 20 Mcf per well per day.

The ALJ found the respondents' forecast to be more reasonable. He noted that they used publicly available data that could be verified, while the complainants' SHALEGAS™ model relied on hypothetical characteristics of a typical well. He also noted that the respondents' forecast

developed economic cutoff points that made realistic assumptions regarding the productive life of an Antrim reservoir.

In their exceptions to the final PFD, the complainants argue that Mr. Frantz used the same public data as Mr. Metzger, but that Mr. Frantz developed forecasts for each project, so that his analysis was more specific than Mr. Metzger's forecasts based on laterals. The complainants further argue that the SHALEGAS™ model is commercially available, is a common means of analyzing Antrim formations, and has gained industry acceptance. They contend that Mr. Metzger's forecasts were not independently verifiable, but that they incorporated his subjective judgment to extrapolate an arbitrary rate of decline from the data.

The complainants claim that Mich Con has previously relied on HR-T's performance of SHALEGAS™ analyses of Antrim production, that Mich Con has developed internal forecasts using a hyperbolic trend applied to each project, and that the forecast of Antrim reserves that Mich Con adopted for 1999 exceeded the one it used in this case by 227 Bcf.

The complainants assert that the respondents have failed to provide an economic justification for imposing arbitrary production cutoff points. The complainants say that the existing lateral charge of 7½¢ per Mcf is more than adequate to justify lateral flows as low as 5,000 Mcf per day and that the economics of maintaining low levels of production could be improved by future supply constraints that exert upward pressure on market prices. The complainants say that project operators are adept at cutting costs during the latter phases of production, so that some shale reservoirs in the Appalachian Basin have continued in operation for 50 to 100 years.

The complainants maintain that a hyperbolic curve best describes an Antrim production trend. They say that focusing on a short period of exponential decline immediately after the peak may obscure the longer term hyperbolic trend. They suggest that Mr. Metzger's approach based on

laterals is imprecise and can obscure individual characteristics of several projects started at different times.

The respondents argue that Mr. Metzger's forecasting methodology is superior to SHALEGAS™ because he did not rely on predetermined production curve overlays or proprietary software algorithms. In essence, the respondents claim, SHALEGAS™ forces the data to fit the contours of a hypothetical well's production patterns. The respondents suggest that HR-T did not design SHALEGAS™ to be Antrim specific and did not use actual Antrim production data in developing the model. They claim that the model makes an arbitrary assumption that all production trends will fit into one of eight possible type curves, only six of which Mr. Frantz applied in this case.

The respondents say that the industry routinely uses exponential decline curves in developing forecasts. They contend that Mich Con's past use of other forecasting methodologies is irrelevant to the accuracy of the forecast they are providing in this case. They contend that the claim that a previous Mich Con forecast exceeds the one in this case by 227 Bcf draws an inappropriate comparison between the current forecast and an outdated one that the complainants adjusted by subtracting actual 1999 production data from the previous year's study.

Forecasting future production is inherently subject to some imprecision, and both of the forecasts presented in this case are to be commended for grounding their analyses in actual data to the extent it was available. Both methodologies also require non-verifiable judgment by the person applying it, who must make basic assumptions regarding future production trends. Notwithstanding Mr. Frantz's and Mr. Metzger's points of disagreement, the outcomes of their forecasts are not that far apart over a five-year timeframe, although they differ by more thereafter.

Having considered the evidence presented by both expert witnesses, the Commission is persuaded that Mr. Frantz's forecast on behalf of the complainants is more reasonable. The complainants have substantiated, without serious dispute, that the SHALEGAS™ model has gained a measure of industry acceptance in the context of shale reservoirs. Although the respondents complain that the model is not Antrim- or Michigan-specific, they do not explain how Antrim formations are different from other shale formations or how their own approach corrects any deficiency in this regard. The Commission also finds merit in Mr. Frantz's application of his forecasting methodology to each of 300 projects, which is more specific than the respondents' analysis based on the production associated with each of 8 laterals. Moreover, Mr. Frantz testified that Mich Con has used methodologies similar to his own in the past, and Mich Con did not deny this.

Appendix A to this order is a computation of the AEP rate that the Commission is approving in this order. The approved rate is equal to the fixed amount (in cents) per volume of throughput that provides for the levelized recovery of the AEP's projected cost of service over the five-year period 2001-05. It incorporates the Commission's determinations regarding the throughput forecast as well as the other issues that affect the rate computation.

Goose Creek Compressor

Prior to the beginning of AEP operation in November 1995, an increasing trend in Antrim production volumes delivered to the Header system caused the operating pressure at the South Chester CO₂ treatment plants to increase and impaired the plants' capability for eliminating CO₂ from the gas stream. This came to light when the respondents discovered that CMS Antrim Gas Company (CMS), the owner and operator of the treatment plants, was diverting untreated gas

around the plant inlet directly to the 20 inch Header in order to reduce the pressure within its facilities.⁵ MichCon Gathering decided to resolve this situation by installing 2,400 horsepower of downstream compression at the Goose Creek interconnection of the Dry Header, which is about midway between South Chester and Kalkaska.

To explain the operating conditions that caused this situation, the respondents note that the design of their facilities requires them to observe certain operating pressure constraints in order to move gas in sufficient quantities and to enable the CMS CO₂ treatment facilities to function properly. They explain that the maximum operating pressure at the South Chester plant outlet is 1,030 pounds per square inch gauge (psig), that the maximum allowable operating pressure of the plants themselves is 1,070 psig, and that CMS personnel had represented that the 40 psig difference in pressure would be adequate to permit the plants to treat the gas. According to the respondents, this turned out to be incorrect: as the outlet pressure approached 1,030 psig, the plants lost treating capability. They say that adding compression at Goose Creek resolved the issue by lowering the outlet pressure by 30 psig while continuing to meet downstream minimum pressure requirements.

In addition to relieving the pressure constraint, the respondents say that the installation of compression at Goose Creek had the beneficial effect of reducing pressure further upstream, thereby permitting the producers to reduce their own costs for field compression facilities and compressor fuel. The respondents say that the compressor also increased the Dry Header's transportation capacity and enabled MichCon Gathering to divert more Antrim gas from the Wet to

⁵There were three CO₂ treatment plants located at South Chester in November 1995, but CMS later added several more. Ex. R-99. Under the CO₂ treating contract that Mich Con signed with CMS, treated gas must have a CO₂ content of 1% or less. Tr. 586.

the Dry Header, leaving only the trapped Antrim production lacking a connection to the Dry Header to continue flowing on the Wet Header. According to the respondents, this produces cost savings because even dry gas incurs processing fees for liquids removal at Kalkaska, if it moves on the Wet Header.

MichCon Gathering incurred \$5.5 million in capital expenditures to construct the Goose Creek Compressor Station, which became operational in May 1996.⁶ Ex. R-150. Because Mich Con had not previously included the Goose Creek Compressor in its AEP proposal in Case No. U-10547, the original AEP rate did not provide for the recovery of the costs related to Goose Creek. In this case, MichCon Gathering proposes to include Goose Creek in the AEP rate base and to recover its costs in the rate.

The ALJ found that the Goose Creek Compressor was a reasonable means of relieving pressure constraints that had prevented the South Chester CO₂ treatment plants from operating at their full capability. He stated that the complainants had failed to demonstrate that any of their suggested alternatives were feasible. He also found that the resulting shift of more Antrim production from the Wet to the Dry Header removes more CO₂ from the gas stream and avoids the unnecessary cost of treating dry gas at Kalkaska. He therefore recommended that MichCon Gathering recover the costs of the Goose Creek Compressor.

In seeking to exclude the Goose Creek Compressor from the rate, the complainants assert that the reduction in CO₂ treating capability is attributable to plants and facilities that CMS owns and operates. They say that Mich Con signed a contract with CMS for the CO₂ treatment, that it is

⁶Beginning in August 1994, Mich Con had a temporary arrangement with ANR Pipeline Company to offload some of its gas at South Chester. This arrangement provided relief for the pressure situation prior to the Goose Creek in-service date. Tr. 388-89; Ex. R-114.

CMS's obligation to fix its own plants, and that the costs of resolving the situation may not be recovered from MichCon Gathering's transportation customers. Noting that the contract makes Mich Con liable to pay demand charges to CMS without regard to actual volumes of gas being treated, the complainants suggest that the respondents may have installed the compressor to protect Mich Con's financial interests. They argue that the separation of operations into two affiliates should insulate the AEP's shippers from the cost of maintaining the CO₂ treatment process, as it is MichCon Gathering that transports Antrim gas and collects the AEP rate, but it is Mich Con that owns the Dry Header and signed the contract with CMS.

The complainants contend that there is no operating constraint that would have justified installing the Goose Creek Compressor. They say that the data points on a graph of pressure readings and plant output in Exhibit R-114 show random fluctuations that do not support a trend. They add that the daily pressure readings at the CO₂ plant inlet and outlet in Exhibit R-148 also show normal fluctuations above and below 1,030 psig and that the exhibit indicates that CO₂ plant outages in the first half of 1994 resulted from numerous unrelated operational failures. The complainants claim that the construction of a second CO₂ treatment plant in 1994 and two more plants prior to the Goose Creek Compressor's in-service date corrected any pressure situation attributable to that timeframe. They say that there is no correlation between the operating pressure at South Chester and excessive CO₂ readings in downstream gas.

The complainants question why the additional transportation capacity provided by the new 16 inch Kalkaska Tie Line, now known as the Wet Header, did not relieve any pressure constraint that might have previously existed on the 20 inch line. They contend that the Wet Header is capable of transporting Antrim gas when blended with Niagaran gas.

The complainants suggest that, by 2002, Antrim production will decline to the point that the added compression will be unnecessary and that, by 2003, total Antrim and Niagaran production will be less than 1994 throughput. Under these circumstances, they assert, MichCon Gathering should not have sought a permanent solution to relieve the pressure and ensure an acceptable CO₂ content. As temporary solutions, they suggest that MichCon Gathering could have blended more Antrim gas on the Wet Header or contracted with ANR Pipeline Company (ANR) for additional capacity.

The respondents contend that their primary reason for installing the Goose Creek Compressor was to provide a permanent solution to high operating pressures that inhibited the CO₂ removal process at South Chester. They say that Exhibits R-114 and R-148 document numerous incidents of high pressure and show a correlation between increased operating pressure and loss of CO₂ treating capability in 1994. They say that the additional CO₂ treatment plants installed throughout this period increased the treating capacity, but had no effect on line pressure.

The respondents say that the construction of the 16 inch Wet Header parallel to the 20 inch pipeline did not relieve the operating pressure at South Chester, but that the design of both lines relies on the assumption that there would be 1,030 psig of operating pressure at the South Chester outlet. They say that shifting too much untreated Antrim gas onto the Wet Header would create the operational hazard that the AEP sought to eliminate—CO₂-induced corrosion. The respondents say that, without the Goose Creek Compressor, the extreme pressure situation would have persisted through 2004. They characterize the complainants' reliance on expected future declines in Antrim production as hoping that the problem will take care of itself.

The respondents dismiss the suggestion that they should have attempted to shift the responsibility for loss of CO₂ treating capability to CMS, as the operator of the plants. They say that the

contract with CMS is ambiguous as to whether CMS has an obligation to treat gas when the pressure would exceed the internal operating limits it observes. They add that disputing the matter would have resulted in protracted litigation at a time when an operational solution was necessary to avoid curtailing the transportation of the Antrim production. They contend that it is speculative to say that Mich Con could have been held legally responsible for the demand charges under the circumstances and that it may have been able to meet its contractual minimum delivery obligations to the CO₂ treatment plants even if the high pressure conditions had forced it to curtail some of the AEP capacity.

The respondents' evidence relating to the necessity for installing the Goose Creek Compressor supports a finding that the compressor was reasonable and that its costs should be recovered through the AEP rate. The evidence identifies the problem that the compressor resolved in operational terms and explains how the pressure constraint adversely affected the transportation of Antrim production within acceptable CO₂ limits. As the respondents have noted, providing a means of Antrim transportation that would meet the CO₂ restrictions was a fundamental purpose of the AEP, and the CO₂ content of Antrim gas presented a hazard that could not be ignored if the AEP and Header system were to function properly. The ownership of AEP facilities by one affiliate, and not another, does not resolve the need to secure an adequate CO₂ treatment capability. Nor does it matter, with respect to operational concerns, that it was Mich Con, and not MichCon Gathering, that signed the CO₂ treatment contract with CMS.

The complainants' attempts to show that the operating pressure was an illusory or exaggerated problem are conjectural and lack a basis in the design and operation of the pipeline. For example, the complainants suggest, but fail to show, that the pressure readings approaching or exceeding 1,030 psig at the South Chester outlet were routine and uneventful, that more Antrim gas could

have been blended with Niagaran gas on the Wet Header, or that more CO₂ could have been tolerated on the Wet or Dry Header. None of their alternatives for dealing with the problem at less cost are demonstrably feasible from an engineering standpoint.

Although the complainants have suggested that Mich Con should have compelled CMS to accept legal responsibility for restoring the CO₂ plants' treatment capability, they do not point to any basis in the contract that would lend support to this view. It was the respondents' judgment that installing the Goose Creek Compressor was a more efficient and time-saving solution than commencing a dispute resolution process with CMS. In view of the apparent success in maintaining continuous access to downstream markets, the Commission is not persuaded to find this judgment unreasonable.

The Commission is also not persuaded that the motivation for installing the Goose Creek Compressor was to serve Mich Con's financial interests at the expense of the economical operation of the AEP. The respondents' explanation of the operational role of the compressor is adequate to dispel this argument. As the respondents have noted, the compressor also enhanced the Dry Header's transportation capacity and provided other benefits within the AEP system, including a significant reduction in the SWEPI processing costs that Antrim gas incurs at Kalkaska when it moves on the Wet Header. Exhibit R-147 indicates that the processing costs to be saved during 2001-05 will exceed by far the Goose Creek Compressor's cost of service for the same period. Moreover, it is unlikely that the respondents would have built the compressor and operated it since 1996 without seeking cost recovery (until this case) if it were in fact superfluous to the proper operation of the AEP.

The suggestion that the respondents should have adopted temporal measures to deal with the pressure situation is also conjectural. It is not clear when an expected decline in Antrim produc-

tion would reduce the operating pressure within limits acceptable to the CMS CO₂ treatment plants.⁷ In any event, without the addition of the Goose Creek compression, the excess pressure situation would have persisted for at least six years, even under the complainants' scenario in which throughput falls to 1994 levels as early as 2002.

In a separate exception, the complainants object to the property taxes related to the Goose Creek Compressor that the respondents have included in the AEP cost of service. This exception is derivative of the issue of whether the decision to install the compressor was reasonable. Because the Commission has answered this issue in the affirmative, it also rejects the exception relating to property tax effects.

Elsewhere in their exceptions, the complainants argue that Section 9 of Act 9, MCL 483.109; MSA 22.1319, required MichCon Gathering to obtain the Commission's approval in advance of constructing and operating the Goose Creek Compressor. The complainants claim that, in the absence of such approval, the respondents may not seek to recover the costs in a complaint case. However, Section 9 has not been construed to prevent a pipeline operator from installing compression equipment on an existing line. The modifications made at Goose Creek were not so material as to require approval in advance under Section 9.

The complainants also argue that the respondents have not met their burden of proof to justify the reasonableness of adding the cost of a new facility to an existing rate. The complainants say that even though they have the burden of proving that the existing rate is unreasonable in light of the costs it recovers, the respondents have the burden with respect to new costs that they seek to

⁷As previously noted in conjunction with the forecast of Antrim throughput, the parties have disputed the rate of production decline, with the complainants taking the position that the decline will be gradual and long-lasting and the respondents projecting a steeper rate of decline.

add to rates. However, the Commission's determination to include the cost of the Goose Creek Compressor in the AEP rate is based on the respondents' showing regarding its reasonableness, which is sufficient to meet their burden of supporting the cost recovery of the compressor.

Depreciation

The March 29, 1995 order in Case No. U-10547, at 58-59, directed Mich Con to depreciate AEP assets in accordance with the unit of production method. Under this method, the AEP's depreciable investment is divided by the projected volumetric throughput over the facilities' productive life to calculate a rate of depreciation per unit of throughput. Depreciation expense is recognized by applying the unit rate to actual throughput. In Case No. U-10547, the unit rate used to compute the depreciation expense reflected in the AEP rate was \$0.03161 per Mcf. Tr. 746.

Since Case No. U-10547, MichCon Gathering has made periodic adjustments to the unit of production rate by recalculating the rate using different forecasts of the AEP throughput. One change in forecasts prolonged the AEP's productive life from 20 to 40 years. Tr. 245-46. The effect was to increase the AEP's projected throughput. As the throughput projections increased, the unit rate decreased, and the AEP's accounting reserve for accumulated depreciation grew correspondingly more slowly. In this case, the respondents project future depreciation expense at a unit rate of \$0.0253 per Mcf. Ex. R-123.

The complainants and the Staff claimed that those depreciation practices are contrary to the methodology approved in Case No. U-10547. The complainants characterized the orders in Case No. U-10547 as approving depreciation at a constant rate of \$0.03161 per Mcf, which could be changed only by Commission order. According to the Staff, the depreciation practices reflected in the company's books have understated the AEP's reserve account for accumulated depreciation,

which in turn caused the rate base to be overstated. The complainants and the Staff proposed to restate accumulated depreciation to reflect depreciation through the end of 2000 at the original unit rate of \$0.03161 per Mcf. The complainants further proposed a prospective unit rate for depreciation of \$0.0125 per Mcf, Ex. C-83, and the Staff proposed \$0.01925 per Mcf, Ex. S-178.⁸

The ALJ adopted the Staff's position regarding the unit rate and accumulated depreciation balance to be used in setting rates. He stated that a premise of the AEP rate approved in Case No. U-10547 was that MichCon Gathering would incur depreciation in a fixed amount per unit, but that the respondents modified their depreciation practices without Commission authorization. In his view, MichCon Gathering has already recovered \$0.03161 per Mcf of depreciation expense as part of the 9¢ per Mcf rate it has charged to date.

In their exceptions, the respondents argue that the other parties and the ALJ have misconstrued the orders in Case No. U-10547 as they relate to depreciation. The respondents contend that their depreciation practices have been entirely consistent with the unit of production method, which requires the unit rate to be adjusted annually to account for changes in the forecast of reserves and productive life. They suggest that variances between projected and actual depreciation expense can be expected in a ratemaking context and are not different from variations in other items of the cost of service used to set the rate. As an example, they make reference to the actual levels of operation and maintenance (O&M) expense, which they say have greatly exceeded the \$100,000 annual allowance used to set the AEP rate in Case No. U-10547. They contend that the Commission may not retroactively modify the depreciation method approved in Case No. U-10547 and that

⁸Notwithstanding the similarities of the positions advanced by the complainants and the Staff regarding depreciation, their projected unit rates differ due to other assumptions relating to the throughput forecast and Goose Creek.

the proposal of other parties to restate accelerated depreciation for past depreciation expense would be retroactive ratemaking. They note that the rate adjustment invalidated in Michigan Bell Telephone Co v Public Service Commission, 315 Mich 533; 24 NW2d 200 (1946), had its basis in a Commission finding that the utility had previously recorded excessive depreciation charges.

In reply, the complainants observe that the difference between projected depreciation at a rate of \$0.03161 per Mcf, as recovered in the AEP transportation rate, and depreciation expense amounting to \$0.02033 per Mcf, as recorded in MichCon Gathering's books, totals at least \$6.8 million. According to the complainants, the respondents are attempting to recover the \$6.8 million twice, once through revenues already collected and a second time by setting the rate to collect it as a future depreciation expense.

The complainants dispute the respondents' contention that the Commission approved a depreciation method without fixing a unit rate in Case No. U-10547. The complainants argue that the depreciation rate was implicit in the approval of the pipeline transportation rate. They point to the March 29, 1995 order in Case No. U-10547, which stated that Mich Con's application "requested authority to establish a new depreciation rate." This is also evident, they say, from Staff witness David J. Berquist's recommendation in that case to fix the unit rate and revise it only after five years had passed. Ex. R-129, at 3. The complainants also say that the periodic revisions mentioned by Mr. Berquist were not to be implemented by the company on a unilateral basis, but were to require Commission approval.

The complainants contend that the depreciation issue is unrelated to the principles discussed in Michigan Bell. They say that their approach would not compel MichCon Gathering to return

excessive revenues it has already collected, but rather it would make a correction for the company's failure to conform its accounting records to the depreciation rate prescribed in Case No. U-10547.

The Staff says that the manner in which MichCon Gathering has recorded depreciation was questionable and manipulative. The Staff states that the company increased the Antrim reserves' productive life from 20 to 40 years immediately after the Commission approved the AEP rate in Case No. U-10547. Although the Staff says that the unit of production method could allow some change in the unit rate from year to year, it asserts that the respondents have provided no explanation to justify an abrupt change that dramatically reduced the depreciation expense. The Staff says that the Commission should order the respondents not to modify the unit rate of depreciation to be approved in this case.

The Staff argues that, unlike depreciation, the allowance for O&M expense in Case No. U-10547 was designed to recover only the AEP's incremental (as opposed to fully allocated) cost and that irregularities in depreciation practices are much harder for other parties to detect. The Staff says that MichCon Gathering has the option to apply for a rate increase whenever it believes that its current rate is not recovering its costs.

The Commission finds that the Staff's position regarding the appropriate accounting for depreciation is reasonable and should be adopted. The company's accounting practices since Case No. U-10547 have ignored basic assumptions underlying the Commission's authorization of depreciation practices. The Commission did not foresee that the respondents would revise the forecasts of the AEP's throughput and productive life in order to push the unit rate of depreciation lower. The Commission agrees with the complainants and the Staff that those depreciation practices are improper and have the effect of distorting the book value of the AEP's net plant in

rate base. For ratemaking purposes, the Commission adopts the Staff's proposals to restate accumulated depreciation balances and to record future depreciation at a unit rate in accordance with the methodology used in Exhibit S-178. The Commission further orders the respondents to apply this unit rate without subsequent revision unless they obtain Commission approval to modify the depreciation methodology or unit rate.

The Commission rejects the argument that the complainants' and the Staff's position on depreciation is a form of retroactive ratemaking. This order does not attempt to recapture past earnings that the company lawfully collected under the rate approved in Case No. U-10547. Unlike the Michigan Bell decision, the Commission is not ordering a refund on the basis of a finding that the past rate was excessive. Instead, the determination in this case is that the respondents have misapplied the depreciation methodology authorized in Case No. U-10547 and that the appropriate remedy is to make a reasonable restatement of those account balances as they were affected by the improper depreciation practices. Moreover, the Commission finds that the account balances presently reflected in MichCon Gathering's books are not reasonable, even if they can be deemed to comply with accounting standards as a technical matter. It is a long-standing principle that the company's accounting treatment does not dictate the Commission's ratemaking decisions. November 16, 1999 order, Case No. U-11636, at 36; December 7, 1989 order, Cases Nos. U-8678, U-8924, and U-9197, at 14-15; August 4, 1987 order, Case No. U-8681, at 25-26; August 4, 1987 order, Case No. U-8680, at 25.

In their exceptions, the complainants propose two further modifications to the Staff's computation of accumulated depreciation. First, the complainants say that the Staff ignored actual throughput for 1995 and consequently understated the accumulation of depreciation in that year by \$154,400. The Commission agrees that this adjustment is appropriate.

Second, the complainants say that the Staff should have reduced the book value of the Goose Creek Compressor to reflect past depreciation beginning with its in-service date in 1996. The Commission does not agree. In Case No. U-10547, the computation of the unit rate of depreciation used an estimate of AEP capital expenditures. For purposes of this case, a “going forward” computation of the depreciation to be expensed over the final five years of the ten-year rate period has been updated for the actual capital expenditures incurred to construct the AEP. This approach reflects net plant as the book value of actual gross plant, including Goose Creek investment, reduced for prior accumulations of depreciation expense. The complainants’ suggestion to reduce further the Goose Creek investment for depreciation during 1996-2000 would be inconsistent with the treatment of other plant assets, which does not require a retroactive restatement of accumulated depreciation balances to reflect differences between projected and actual capital expenditures.

Appendix B to this order applies the depreciation methodology in Exhibit S-178 with the other determinations in this order (including the throughput forecast) to compute a unit rate of depreciation of \$0.01666 per Mcf. The Commission adopts this unit rate for purposes of computing the AEP transportation rate to be approved in this order (as set forth in Appendix A). As noted, MichCon Gathering must apply this unit rate without change when recording future depreciation, unless it obtains prior authorization from the Commission to modify the depreciation methodology or unit rate.

In their exceptions, the complainants propose one further adjustment affecting rate base. They say that the rate base in the final PFD, which purports to adopt the Staff’s position, increases the amount proposed by the Staff by about \$7,000 in 2001 without explanation. Mich Con responds that, even if there is a discrepancy, the difference would not survive the rounding of the numbers used to compute the transportation rate.

The difference in rate base between the Staff’s computation and the final PFD is minimal. Furthermore, it can be explained by the respondents’ acceptance of an adjustment making a slight reduction to the volumes of Antrim gas transported over the Wet Header in 2000, which reduced the throughput used to calculate AEP depreciation for that year. See respondents’ initial brief, at 39-40 & n.38, which compares the respondents’ Exhibit R-135 with the Staff’s Exhibit S-178.

Cost of Capital

The parties stipulated to the cost of capital. Tr. 84-85. The stipulated cost of capital is as follows:

	<u>Capital Structure</u>	<u>Rate of Return</u>	<u>Weighted Average Cost of Capital</u> (A x B)
	(A)	(B)	
Debt	47%	6.97%	3.28%
Equity	53%	11.65%	+ <u>6.17%</u>
			<u>9.45%</u>

The Commission finds that the stipulated cost of capital is reasonable for purposes of the AEP rate computation. The amount shown above is on a post-tax basis and is the equivalent of the pretax cost of capital of 13.04% for 2001⁹ in Appendix A.

⁹The pretax cost of capital decreases slightly from year to year due to anticipated reductions in the Michigan single business tax.

O&M Expense

The respondents projected their allowance for O&M expense by escalating \$1,738,000¹⁰ of actual O&M expense incurred in 1999 by an annual inflation factor of 2.45%. With one adjustment, the ALJ accepted the respondents' O&M expense projections. The adjustment was to disallow \$423,000 (in 1999 dollars¹¹) for corporate cost allocations, which represent charges for direct and common costs incurred on behalf of MichCon Gathering and other affiliates within the holding structure of MCN Energy Group, Inc. (MCN). The ALJ stated that the respondents had not demonstrated that the cost allocation methodology was appropriate or that the costs in question were not already being recovered in Mich Con's base rates.

In their exceptions, the respondents argue that corporate allocations are necessary costs of maintaining a separate subsidiary. They categorize the \$423,000 in disputed costs as follows: \$157,700 of direct charges, \$213,300 of indirect charges, and \$52,000 in MichCon Pipeline allocations.¹² They explain that the direct charges are compensation for services provided to MichCon Gathering by holding company personnel and include such functions as corporate planning and development, internal audit, tax preparation, and legal and financial services. They explain that the indirect charges recover common costs that cannot be attributed to a specific subsidiary, relate to such functions as accounting, executive office operations, human resources,

¹⁰As set forth in Exhibit R-153, the 1999 O&M expense includes \$456,000 relating to company use and lost and unaccounted for gas that the respondents subsequently agreed to remove from O&M expense. This order discusses the circumstances of this adjustment in relation to the retainage issue.

¹¹Unless otherwise indicated, dollar amounts of O&M expense in this discussion refer to 1999 dollars before escalation.

¹²MichCon Pipeline, one of the named respondents, is MichCon Gathering's immediate parent company.

tax, and legal and financial services, and are determined in accordance with the generally accepted Massachusetts formula. They explain the MichCon Pipeline allocations as the costs incurred for joint billings of pipeline customers for services provided by several affiliates.

In their exceptions, the respondents argue that the direct charges and MichCon Pipeline allocations represent incremental costs, in the sense that they would not have been incurred if the AEP operation had not been transferred to a subsidiary separate from Mich Con's utility operation. They claim that not allocating the costs would subsidize the Dry Header with Mich Con's revenues. They say that it is erroneous to assume that Mich Con's rates already recover the costs as part of the utility's cost of service, given that neither the AEP nor MichCon Gathering were in existence on October 28, 1993, when the Commission issued its order authorizing Mich Con's current base rates in Cases Nos. U-10149 and U-10150 (Case No. U-10150 et al.). Moreover, they say, the orders in Case No. U-10547 did not provide for the recovery of costs allocated to a separate subsidiary because the decision to form MichCon Gathering had not then been taken.

In reply, the complainants say that the respondents failed to explain how they performed the cost allocations, so that there is no basis in the record to determine whether the allocations were proper or actually relate to the AEP. The complainants say that there is no indication in Case No. U-10150 et al. that the Commission endorsed the Massachusetts formula, even if it could be verified that the respondents are actually using the formula at the present. The complainants argue that Mich Con's rates already recover the costs at issue, so that allocating them to the AEP rate would produce a double recovery. They claim that, in the absence of a demonstration as to how the methodology works, it cannot be determined whether the allocations are truly incremental to other costs incurred by or on behalf of Mich Con and other subsidiaries and affiliates. They add that the sequence in time in which MCN formed the affiliates is irrelevant, but that the real

question is whether the costs had been incurred prior to the AEP, even if the respondents now choose to allocate them to a different legal entity.

The Staff also opposes the cost allocations. It says that establishing Mich Con Gathering as a subsidiary created a new cost center for allocating direct and indirect costs, but that it cannot tell whether the respondents have made the allocations properly. The Staff says that the respondents have failed to identify and distinguish between costs being recovered in Mich Con's present rates and those they propose to recover in the AEP rate.

The Commission adopts the ALJ's finding to disallow the corporate allowances from O&M expense. The record does not provide an adequate basis to review the mechanics of the methodology used to allocate the costs among MCN's various affiliates. Although the respondents emphasize their reliance on the Massachusetts formula, they do not explain how the methodology works or show that the cost allocations it assigned to the AEP are reasonable. The October 28, 1993 order in Case No. U-10150 et al. does not lend support to the formula, but instead the Commission noted shortcomings in the allocation practices used in those cases and adopted a significant reduction to the cost allocations that Mich Con had proposed to recover in its base rates. Order at 58-62.

The lack of documentation supporting the respondents' allocations makes it unclear whether the costs are in fact incremental to costs being recovered in Mich Con's base rates. In Case No. U-10547, the AEP transportation rate was calculated to recover the pipeline's estimated cost of service over a levelized ten-year period, and the allowance for annual O&M expense of \$100,000 was projected as an amount that would be incremental to the costs already being incurred in Mich Con's utility operation. In this case, the Commission seeks to maintain consistency with the original rate assumptions in providing for the recovery of the AEP's levelized cost of service

for the last five years. The respondents' presentation regarding O&M expense provides no assurance that they are being consistent with the rate assumptions used in Case No. U-10547.

In Exhibit R-153, the respondents propose to recover additional types of O&M expense, including \$239,000 for the Goose Creek Compressor, \$112,000 of costs related to pipeline operation, and \$508,000 of administrative expense. In their exceptions, the complainants assert that the ALJ failed to address further O&M disallowances that they had proposed in Exhibit C-84. In that exhibit, the complainants' witness Richard Metz analyzed each line item in Exhibit R-153 and proposed a series of adjustments. For example, Mr. Metz found that \$74,000 incurred for property insurance in 1999 was a lump sum payment that provided coverage for several years. He adjusted the annual amount to approximately \$19,000. Tr. 200-01. Mr. Metz further identified two cost items amounting to \$29,000 that represented the amortization of one-time expenditures and, in his view, should not have been escalated for inflation.

The complainants reiterate their arguments that the amounts proposed for O&M expense (in addition to the cost allocations) are not incremental costs and are being recovered in Mich Con's rates. The complainants observe that, except for \$112,000 of pipeline-related costs, the total O&M expense that the respondents are proposing is not comparable to the \$100,000 of incremental O&M expense estimated in Case No. U-10547. The complainants also oppose any Goose Creek O&M expense for the same reasons that they opposed the inclusion of the compressor in rate base.

In reply, the respondents argue that the \$100,000 allowance for O&M expense in Case No. U-10547 was a conservative estimate and that operating experience has proven that actual expenses are much higher. The respondents claim that the suggestion that their O&M expense is

not incremental in nature is speculation and has no basis in the cost estimate they used in Case No. U-10547.

The Commission finds that the O&M expense component related to the Goose Creek Compressor (except for compressor fuel¹³) should be recovered through the AEP rate for the reasons it cited in finding that the compressor should be included in the AEP rate base. As indicated by Mr. Metz, the O&M expense allowance of \$112,000 for pipeline-related costs is reasonable. The Commission further finds that reducing the administrative component of O&M expense (including property insurance) from \$508,000 to \$374,000 is reasonable in light of Mr. Metz's analysis of the individual line items. See Ex. C-84, at 3. The Commission is not persuaded by the argument that it should disallow the O&M expense in its entirety on the ground that none of it is incremental. It is reasonable to infer that the operation of the AEP through a separate affiliate would incur some expense on an incremental basis. Moreover, the Commission does not agree that some costs should be immune from escalation simply because they are an amortization expense. Even if that is true for particular transactions, those types of expenses are likely to recur over time and would be susceptible to inflationary influences.

In light of these findings, the approved allowance for O&M expense in 2001 is \$725,000 in 1999 dollars before escalation at 2.45% annually.

Gas-in-kind Retainage

Pursuant to its contracts with AEP customers, MichCon Gathering currently retains 0.5% of the gas delivered by the shippers as compensation for company use and lost and unaccounted for gas. Instead of determining the projected revenue and cost effects of retainages (as part of O&M

¹³See supra note 10.

expense), the ALJ accepted the respondents' suggestion to exclude retainages from the AEP cost of service and reduce the retainage percentage to 0.17%. In Exhibit R-157, the respondents based their proposed retainage on the Dry Header's average volumes of lost and unaccounted for gas during 1996-99 and the average volumes of company use gas (i.e., fuel for the Goose Creek Compressor) during 1998-99.

In their exceptions, the complainants propose a retainage of 0.06% if they prevail on their claim that Goose Creek costs, including compressor fuel, should be excluded from the AEP rate, or 0.12% if compressor costs are recoverable. They reiterate their argument that the Goose Creek Compressor was unreasonable. They also argue that the retention percentage should have been computed by dividing historical company use and lost and unaccounted for gas volumes by total volumes delivered to the AEP for the same historical period, and not by projected volumes for future periods, as computed in Exhibit R-157.

Again, the Commission rejects the contention that costs related to Goose Creek should be disallowed. However, the Commission agrees with the complainants that it is appropriate to determine retainages on the basis of historical percentages of volumes attributed to company use and lost and unaccounted for gas. Therefore, the Commission directs MichCon Gathering to revise its retainage percentage to 0.12% and to take any steps necessary as a matter of contract administration with its shippers to implement this change.

Wet Header Charges and SWEPI Processing and KIF Fees

As previously explained, some Antrim gas continues to move on the Wet Header, even after the installation of the Goose Creek Compressor, and Mich Con charges MichCon Gathering its tariff transportation rate of 2.2¢ per Mcf for that gas. Because the Wet Header connects with

SWEPI's Kalkaska Processing Plant, the Antrim volumes on the Wet Header also incur SWEPI processing and Kalkaska Inlet Facility (KIF) fees, even though the Kalkaska plant is designed to extract liquids from wet gas, not dry Antrim gas. MichCon Gathering charges shippers a uniform AEP rate for Antrim gas, regardless of which Header the gas uses on its way to market. In this case, the respondents propose to include MichCon Gathering's payment of Wet Header tariff charges and Kalkaska processing and KIF fees in the AEP cost of service, so that those charges and fees are recovered in the AEP transportation rate paid by all Antrim shippers.

The ALJ agreed with the respondents that the Wet Header charges and SWEPI fees should be recovered in the AEP rate.

In their exceptions, the complainants oppose cost recovery of the Wet Header charges and SWEPI processing and KIF fees. They argue that there is no need to treat Antrim gas at the Kalkaska plant and question why MichCon Gathering should assume an obligation to pay fees to SWEPI under a processing contract signed by Mich Con. They say that MichCon Gathering has already attained the cost savings from shifting more Antrim gas from the 16 inch Wet Header to the 20 inch Dry Header through the construction of the Goose Creek Compressor and additional Antrim laterals, even as they question the need for the compressor or the laterals.

The Commission finds that this exception should be rejected. Although the complainants question MichCon Gathering's obligation to pay SWEPI processing and KIF fees on Antrim

volumes using the Wet Header, they point to nothing in the longstanding contractual relationship between Mich Con and SWEPI that would provide a defense to the fees.¹⁴ The marked reduction in Antrim gas now flowing on the Wet Header is reflected in the projected Wet Header volumes used to compute the AEP rate. The reduction does benefit the complainants by minimizing the Wet Header charges and SWEPI fees included in the AEP cost of service. According to the respondents, the only Antrim gas that now incurs the charges are those volumes that remain trapped on the Wet Header.

Although the complainants attempt to interject prudence issues related to Goose Creek, the Commission has already found Goose Creek compression-related costs to be recoverable in the AEP rate. Exhibit R-147, a cost/benefit analysis of the Goose Creek Compressor, indicates that anticipated cost savings resulting from shifting more Antrim production from the Wet to the Dry Header was a significant factor in undertaking the installation of the compressor. As discussed below, the Commission is finding in this order that the decision to construct the two Antrim laterals was also reasonable. It is thus reasonable to include the Wet Header charges and SWEPI fees to be incurred for the reduced volumes of Antrim gas in the AEP cost of service.

SWEPI Keep Whole Charges

Mich Con entered into a 1971 processing contract with SWEPI to treat gas at Kalkaska. Ex. C-145. The processing contract assigns SWEPI both the exclusive right and obligation to

¹⁴As discussed later in this order, a recurring theme of the complainants is that the AEP rate charged by MichCon Gathering cannot recover costs resulting from Mich Con transactions to which Mich Con Gathering was not a party. However, this does not change the fact that AEP operation caused the charges to be incurred. Separate affiliate status could be a defense if SWEPI were to sue MichCon Gathering for payment, but it does not resolve the issue of whether the costs are assignable to the AEP's cost of service.

extract the liquids from gas flowing on the Wet Header. By the early 1990s (prior to the AEP), the Wet Header was receiving increasing volumes of Antrim production that created a capacity constraint. To relieve the constraint, Mich Con proposed to bypass some of the gas (both Niagaran and Antrim) around the Kalkaska plants, but SWEPI objected and asserted its contractual right to treat the gas. To settle their differences, Mich Con and SWEPI negotiated a Keep Whole Agreement dated May 5, 1993. Ex. C-143. The Keep Whole Agreement provides that Mich Con will compensate SWEPI for the processing fees and the economic value of selling extracted liquids that SWEPI would otherwise lose when Mich Con diverts gas around the Kalkaska plants. The agreement also acknowledges that Mich Con has the right to bypass Antrim gas around the plants without paying compensation.

After the AEP became operational, some Niagaran production continued to flow on the 30 inch former Wet Header, which, after being converted to the Dry Header, bypassed the Kalkaska processing plants. The respondents acknowledge that they owe compensation to SWEPI under the Keep Whole Agreement for those volumes. To reduce those obligations, the respondents have since constructed five additional Niagaran laterals to divert more Niagaran gas to the 16 inch Wet Header (as discussed below). For the remaining wet volumes that the respondents expect to move on the Dry Header during 2001-05, they proposed to include Keep Whole payments to SWEPI amounting to 36¢ per Mcf in the AEP's cost of service.

The ALJ found that the Keep Whole compensation should be included in the AEP's cost of service, stating that those payments are an economic consequence of the respondents' decision to construct and operate the AEP. He further found that the respondents had appropriately estimated the Keep Whole charges at 36¢ per Mcf by relying on SWEPI billings covering 1996-99. The

complainants had estimated Keep Whole charges of 18¢ per Mcf on the basis of a more recent bill received from SWEPI in November 2000.

In their exceptions, the complainants renew their objections to the SWEPI Keep Whole charges. They argue that Mich Con, and not MichCon Gathering, was the legal entity that incurred the Keep Whole charges and that the AEP, which belongs to MichCon Gathering, should be shielded from Mich Con's costs. The complainants say that Mich Con, as the entity filing the application to construct the AEP in Case No. U-10547, is responsible for any costs resulting from its decision to construct the AEP.

The complainants argue that the omission of Keep Whole charges from the initial cost of service in Case No. U-10547 suggests that Mich Con did not believe those costs to be valid or related to the AEP and acts as a waiver of any right of recovery. The complainants observe that Mich Con is actively disputing the billings with SWEPI and has never conceded the amount of liability. The complainants also suggest that the respondents failed to provide adequate information regarding the non-Antrim Dry Header volumes that would incur the Keep Whole charges in the future.

The complainants further contend that the Keep Whole charges should be estimated at 18¢ per Mcf, which reflects SWEPI's most recent billing of the charges. The complainants urge that it is appropriate to use the most recent information available because the charges vary with the market price of the liquid hydrocarbons that SWEPI extracts and sells.

The respondents reply that excluding the Keep Whole charges from the AEP cost of service would ignore the causal relationship between those charges and the AEP operation. They add that MichCon Gathering did not exist at the time of Case No. U-10547, that omitting the charges in that case lowered the initial AEP rate, and that Mich Con did not have adequate information to estimate

the charges at that time. The respondents claim that the obligation to pay the charges is undisputed and that it has already paid SWEPI \$1 million toward its liability.

In its reply, SWEPI argues that incurring some Keep Whole charges is the most cost efficient means of developing an alternative transportation system for Antrim gas and that, but for the AEP, the charges would not have been incurred. It contends that including the charges in the AEP cost of service is consistent with the principle that the AEP should not adversely affect the rate paid by non-Antrim producers to transport their gas on the Wet Header system.

SWEPI argues that the charges are reasonable and that the complainants are asserting overly technical details to obscure the underlying principles of cost causation and allocation. SWEPI says that, for ratemaking purposes, which affiliate holds title to which facility is irrelevant, but that the issue is to identify the assets and costs that are attributable to Antrim transportation. SWEPI also suggests that, regardless of MichCon Gathering's role in operating the AEP, Mich Con retains the ultimate responsibility for transporting Antrim gas.

The Commission finds that it would not be reasonable to disallow the Keep Whole charges on the theory that they are Mich Con's contractual responsibility and therefore cannot affect MichCon Gathering's cost of providing AEP service. As stated in the March 29, 1995 order in Case No. U-10547, at 50-52, the Commission granted Mich Con discretion to establish a separate ownership structure for the AEP in order to facilitate its efforts to secure non-recourse financing and to separate the AEP's accounting, operation, and management functions from Mich Con's utility operation. The formation of MichCon Gathering did not insulate AEP shippers from costs legitimately incurred to provide them service, even if the entity with the formal obligation to pay the charges was another affiliate. At the time that the Commission authorized the AEP in Case No. U-10547, MichCon Gathering was not in existence, and it can be presumed that, upon its

formation, it assumed the rights and responsibilities previously granted in the name of Mich Con with respect to the AEP. Nothing in the Commission's decision in Case No. U-10547 suggests that Mich Con, acting either on behalf of itself or any future successor in interest, was waiving any right to seek recovery of reasonable costs that might arise in future cases.

Incurring some Keep Whole charges is a reasonable means of resolving operational constraints caused by the commingling of Antrim production with other kinds of gas. The reason that the Dry Header continues to accommodate some non-Antrim volumes is the respondents' determination that it is more economical to incur some Keep Whole charges than to undertake the construction of facilities necessary to separate all Antrim and non-Antrim gas. The complainants have not demonstrated that there are more cost efficient alternatives. Moreover, using the AEP rate to recover the Keep Whole charges associated with residual flows of non-Antrim gas is consistent with the principle observed in Case No. U-10547 in establishing the initial AEP rate: that the additional costs of constructing a parallel system for transporting Antrim gas to market should not adversely affect the Wet Header transportation rate paid by non-Antrim shippers.

The complainants have also argued that estimating Keep Whole charges at 36¢ per Mcf is excessive. It should be noted that the amount of the charges is a matter of ongoing dispute between Mich Con and SWEPI and that SWEPI has issued several bills in the course of their negotiations. One factor contributing to the difficulty in projecting future charges is the lack of explanation as to how the parties believe the charges should be computed under the framework set forth by the Keep Whole Agreement. Exhibit C-175, a copy of an updated bill issued by SWEPI in November 2000 covering the period November 1995 through June 2000, provides no detail other than dollar amounts of charges for each calendar month.

To compute their estimate of 36¢ per Mcf, the respondents used total Keep Whole charges billed in June 1997 of \$2.1 million covering the period November 1995 through April 1997 and divided the total by 5.8 Bcf of non-Antrim gas. Using the more recent SWEPI billing submitted as Exhibit C-175, the complainants computed their estimate of 18¢ per Mcf by dividing the Keep Whole charges for calendar year 1999 by the non-Antrim volumes reported for the same year in Exhibit C-158. Using Exhibit C-175 to perform a similar computation for the entirety of 1996-99, the respondents estimated the charges at 34.1¢ per Mcf, respondents' reply brief, App. B, which they say is reasonably close to the estimate of 36¢ per Mcf that the ALJ adopted.

The Commission is not inclined to accept at face value an estimate of a controverted amount based on an outdated bill, particularly if better information is available. The Commission finds that the complainants' proposed estimate of 18¢ per Mcf is more reasonable under the circumstances and should be used for ratemaking purposes in this case. It finds merit in the complainants' argument that it is appropriate to use more recent information in computing the estimate.

Additional Laterals

After the AEP became operational in November 1995, Mich Con constructed several additional laterals to the Header system. The purpose of these laterals was to segregate more of the Niagaran and Antrim production on the Wet and Dry Headers, respectively.

Two of the additional laterals connected Antrim wells with the Dry Header.¹⁵ In addition, Mich Con made arrangements with a producer, Ward Lake Energy, to have another Antrim lateral constructed. The third Antrim lateral, known as Ward Lake Lateral 93, was to be transferred to

¹⁵The Commission issued orders granting Act 9 authorization for the two Antrim laterals on May 11, 1998 in Case No. U-11624 and June 26, 1998 in Case No. U-11681.

Mich Con for consideration of \$90,000 when complete in September 2000.¹⁶ The Antrim laterals avoid Wet Header charges and SWEPI processing and KIF fees that Antrim gas would otherwise incur if it were to continue to flow on the Wet Header. The respondents also indicated that accumulating more Antrim gas on the Dry Header enhances the capability of the system to accommodate gas with a high CO₂ content.

During 1998 and 1999, Mich Con also constructed five additional laterals to gather Niagaran production and redirect it from the Dry to the Wet Header.¹⁷ The respondents said that the savings realized by avoiding the SWEPI Keep Whole payments justified the cost of those laterals.

Mich Con holds title to the additional Antrim and Niagaran laterals, but MichCon Gathering compensates Mich Con for their cost of service. The respondents propose to recover those costs through the AEP rate. This recovery would be cumulative to the revenues that Mich Con collects by charging shippers 7½¢ per Mcf for using the lateral system.

The ALJ agreed with the respondents that the cost of the additional laterals should be recovered through the AEP rate. He reasoned that those laterals are an integral part of the AEP operation and serve to improve its efficiency. He found that the Antrim laterals reduce the SWEPI processing fees and Wet Header charges, that the Niagaran laterals minimize exposure to the SWEPI Keep Whole charges, and that both types of laterals improve the CO₂ treating capability.

In their exceptions, the complainants reiterate that costs incurred by Mich Con cannot be recovered by MichCon Gathering, which is a separate affiliate. The complainants say that

¹⁶The Commission approved the Ward Lake Lateral 93 in the August 31, 2000 order in Case No. U-12416.

¹⁷The Commission granted Act 9 authorization for the five Niagaran laterals on May 11, 1998 in Case No. U-11623, June 26, 1998 in Cases Nos. U-11679 and U-11680, September 23, 1998 in Case No. U-11774, and November 16, 1999 in Case No. U-12141.

disallowing the Niagaran lateral costs is appropriate because Mich Con, not the AEP shippers, receives the benefit in the form of reduced Keep Whole charges. The complainants contend that any operational or financial hardships resulting from trapped Antrim gas being blended with Niagaran gas are the result of decisions that Mich Con made when it designed the AEP. The complainants also question why it is appropriate to make any provision for the lateral costs, given that Mich Con already collects a lateral charge of 7½¢ per Mcf.

The complainants further argue that the respondents failed to meet their burden of proving that the laterals are reasonable. The complainants assert that the ex parte orders authorizing the laterals do not speak to whether the costs are reasonable. They say that the respondents did not attempt to quantify any of the purported cost savings related to the Antrim laterals. They claim that the actual expenditures to construct the Niagaran laterals overran Mich Con's cost estimates by 42% and exceeded the expected savings. According to the complainants, Mich Con conceded that, even without the laterals, it had the physical capability to cross the flow of gas between the Dry and Wet Headers and that some laterals had dual feed valves connecting to both Headers. The complainants note that Mich Con did not construct the laterals until some time after it constructed the AEP and SWEPI issued the first Keep Whole billing. By the time that the laterals went into service beginning in 1998, the complainants say, the respondents' forecasts showed declining volumes of both Niagaran and Antrim production.

With respect to the claim that the laterals enhanced the system's CO₂ treating capability, the complainants suggest that any need in this regard should have ended once CMS completed five CO₂ treatment plants at South Chester. If, however, that premise has any validity, the complainants suggest that the Commission reallocate 10% of the cost of the Niagaran laterals to CMS.

In reply, the respondents argue that the costs that MichCon Gathering reimburses to Mich Con for the laterals are reasonable and benefit the AEP's operation and shippers by reducing other charges and enhancing the CO₂ treating capability. They observe that the Commission issued orders approving each lateral. They explain that the cross-over capabilities that the complainants claimed were in place prior to the laterals refer to valves that diverted Antrim gas treated at South Chester from the plant outlet to the Wet Header, but that those valves became inoperative once the Goose Creek Compressor entered into service and increased the Dry Header's capacity.

The respondents say that the Commission approved Mich Con's lateral charge of 7½¢ per Mcf in the October 28, 1993 order in Case No. U-10150 et al. They explain that the charge does not recover the cost of the additional laterals that Mich Con has since constructed to provide more separation of Antrim and Niagaran gas, which distinguishes those laterals from the laterals that predate the AEP.

SWEPI also supports cost recovery of the laterals. It says that the laterals are an integral part of the AEP and that the savings more than offset the costs. SWEPI suggests that the laterals restore to Niagaran shippers the capability they had to transport their gas on the Wet Header prior to the AEP.

Some of the observations made in conjunction with the SWEPI Keep Whole charges also apply to the laterals. Just as MichCon Gathering's affiliate status does not automatically insulate it from the cost responsibility for the Keep Whole charges incurred under a contract that Mich Con signed with SWEPI, Mich Con's ownership of the laterals does not necessarily foreclose the costs from being recovered in the AEP rate. In both cases, the important question is whether the costs are reasonable and are attributable to the AEP operation.

As stated in relation to the Keep Whole charges, a working assumption of the AEP is that the rate should absorb the additional costs of constructing and operating a parallel transportation system for Antrim gas and that none of those costs should be shifted to the Wet Header's non-Antrim customers. This principle also applies to the laterals that Mich Con constructed to improve the efficiency of the AEP. Those laterals would not have been necessary but for the construction of the AEP to transport Antrim gas, as the laterals previously in place provided a means of access for both Niagaran and Antrim production to the Wet Header. Moreover, the lateral charge of $7\frac{1}{2}\text{¢}$ per Mcf does not affect the cost recovery of the additional laterals built to facilitate AEP operation, but it recovers the costs incurred for the lateral system that was functioning prior to the AEP.

The analysis used to determine whether to build the laterals is a cost trade-off against incurring the charges owed to SWEPI and the Wet Header transportation charges. The Commission's finding that charges incurred due to the blending of wet and dry gas on the Header system can be recovered when appropriate also disposes of the complainants' argument that the costs of laterals built to avoid those charges are unrelated to the AEP. Furthermore, the record does not support a finding that the costs were inappropriate or excessive. That there may have been cost overruns does not necessarily mean that some or all of the costs were imprudent.

Although the complainants argue that the costs were unreasonable in light of the circumstances, much of what they claim is conjecture. For instance, the complainants claim that the laterals duplicated a preexisting cross-over capability between the Wet and Dry Headers, but they do not say how this capability worked. The respondents explained that the capability formerly existed at South Chester and enabled dry gas to be combined with wet gas when entering the Wet Header. The complainants do not explain how, prior to the construction of the additional laterals,

the wet and dry gas could have been kept separate in the gathering lines and laterals shared by Antrim and Niagaran wells before flowing onto the Header system.

The complainants' alternative proposal to reduce Niagaran lateral costs by 10% as a means of recognizing a benefit conferred upon CMS is arbitrary and without justification. Improving the separation of wet and dry gas does increase the capability to process Antrim gas and helps to ensure an acceptable CO₂ content on the Header system. However, it is unclear how this enhancement benefits CMS's operation of the South Chester CO₂ treatment plants.

ANR Contract Capacity

Since 1994, Mich Con has held a contractual entitlement to ANR pipeline capacity that provides for the receipt of gas at South Chester and Charlton and delivery at Kalkaska. Although the ANR contract expires at the end of 2001, Mich Con intends to renew it. The respondents propose to include the estimated annual demand charge for the contract of \$400,000 in the AEP rate. They claim that the ANR capacity enhances the reliability of the AEP by providing backup transportation in the event of a Dry Header outage or other constraint caused by a loss of compression or unexpectedly high deliveries to the Dry Header. They add that the ANR capacity gives them the flexibility to offload gas with a high CO₂ content.

The ALJ recommended including the cost of the ANR contract in the AEP cost of service. He accepted the respondents' claim that the contract capacity improves reliability by providing an alternative means of transporting gas when compressors fail or CO₂ treatment plants undergo outages. He said that the ANR capacity was in fact used as backup in July, August, and November of 1999 and avoided temporary shutdowns of the Dry Header.

In their exceptions, the complainants claim that the respondents have exaggerated the risks that the ANR contract mitigates. The complainants observe that the Dry Header has never had an outage. They say that the constraints experienced in the past related to facilities operated by CMS or SWEPI and that the contract addresses risks that are the responsibility of third parties. Even then, the complainants say, the few incidents of mechanical failure were short-lived, and the actual volumes that flowed on the ANR pipeline were insignificant. The complainants do not foresee a need for the incremental ANR capacity in light of expected declines in future Antrim production. They claim that non-renewal of the contract would not necessarily foreclose access to the ANR pipeline if an unexpected need arose, but that the pipeline could be used on an interruptible basis or the producers could acquire their own capacity from ANR directly. They say that the ANR contract with Mich Con is anticompetitive.

The complainants argue that the contract's real purpose is to protect Mich Con's financial interests by minimizing its exposure to pay demand charges for gas that the CMS South Chester plants do not actually treat. The complainants suggest that it is unlikely that all five of CMS's CO₂ treatment plants would break down at once. They say that it is not clear in any event that the ANR pipeline can accommodate untreated gas with excessive CO₂ and that, even if it could, the untreated gas could not move past Kalkaska. As an alternative to renewing the contract, the complainants claim that untreated gas could be blended with other gas at South Chester or further downstream while being transported on the Dry Header.

The complainants also rely on a cost/risk analysis that indicates that the time value of deferring sales of gas affected by a transportation outage would justify the cost of the ANR contract only if an outage lasts longer than 92 days. They argue that even if the market price of gas should rise to \$10.00 per Mcf, it would be necessary for an outage to last 47 days to justify the cost. Although

federal tax credits for Antrim gas could affect this analysis, the complainants note that the credits expire at the end of 2002.

The respondents contend that some AEP facilities have undergone outages and that the ability to use ANR capacity saved the Dry Header from a complete shutdown. They say that contractually reserving a majority of the ANR pipeline capacity does not inhibit competition because Mich Con does not control all of the capacity.

The Commission finds that the complainants' exception relating to the ANR contract costs should be rejected. The respondents have presented valid operational reasons for securing backup transportation capacity from ANR. Although the complainants object to the cost, they are unable to demonstrate that the operational reasons for maintaining the backup capacity are invalid. The record shows that the reliability and continuity of service provided to date could not have been maintained without the capacity. If a pipeline outage were to occur without backup capacity, attributing its causation to some other party's facilities is not likely to be meaningful to shippers facing the consequences of a curtailment. An outage would harm the producers, shippers, end-users, and all others who depend upon the AEP as a means of reliable transportation.

Receipt Point Meters and Facilities

Receipt points refer to the property, metering equipment, and related facilities that provide the interconnections between the pipeline and the lines gathering and delivering gas from production areas. In the October 28, 1993 order in Case No. U-10150 et al. at 45-46, the Commission made an adjustment to remove expenses associated with the receipt points on the Wet Header (as it existed prior to the AEP) from the O&M expense used to compute the Wet Header rate. This

finding recognized that Mich Con had been recovering receipt point expenses through a separate fee of \$600 per meter per month.

The complainants and the Staff proposed to include the receipt points' costs and revenues in the AEP cost of service. As computed by the Staff in Exhibit S-183, this adjustment produces net revenues of more than \$600,000 for each of the remaining five years of the levelized period. The ALJ adopted the Staff's adjustment, finding that the receipt points are an integral part of the operation of the AEP.

In their exceptions, the respondents argue that the ALJ's recommendation is inconsistent with the approach previously authorized in Cases Nos. U-10150 et al. and U-10547. They argue that Mich Con has historically managed its receipt points as a single, self-contained program funded by a monthly fee of \$600, as provided in the contracts with the producers. The respondents distinguish the receipt point revenues and expenses from other costs at issue in this case, in that the receipt points preceded the AEP and their expenses are not incremental to costs incurred prior to the AEP.

In reply, the Staff claims that Mich Con established the \$600 monthly fee at a time when it was approximately equal to the costs it recovered. When the AEP came into being, the Staff says, Mich Con transferred ownership of the receipt point meters connected to the Dry Header to MichCon Gathering, and the fees being charged for the receipt points now overrecover the costs by an excessive amount.

The complainants support the Staff's position. They argue that the respondents misconstrue the order in Case No. U-10150 et al., which does not address the propriety of excluding the revenue and cost effects of the receipt points from the pipeline's cost of service. The complainants say that the order in Case No. U-10547 does not discuss receipt points at all. They argue that

receipt points cannot be distinguished from any of the other costs that the respondents are now seeking to insert in the AEP rate for the first time, e.g., the Goose Creek Compressor.

The Commission adopts the ALJ's recommendation regarding the appropriate treatment of the receipt point net revenues. The receipt points belong to MichCon Gathering, are physically connected to the pipeline, and are integral to the AEP's facilities and operation. The respondents have provided nothing grounded in the operational characteristics of the AEP to find otherwise, and it is difficult to conceive how the AEP could perform its functions without receipt points. Thus, there is no reason to exclude the net revenues that MichCon Gathering realizes from receipt points.

The prior orders cited by the respondents do not dictate the treatment of receipt points. In Case No. U-10150 et al., the Commission reduced Wet Header O&M expense out of a recognition that Mich Con was recovering and accounting for the receipt point expenses separately. The Commission did not approve the \$600 monthly fee, but it acknowledged only that Mich Con was collecting it. In Case No. U-10547, the orders do not address receipt points as a contested issue. However, even if today's order could be regarded as a departure from a prior authorized practice, the change in treatment is appropriate. It would not be reasonable to acquiesce in the continued collection of the receipt point fee without regard to its current costs simply because that treatment may have been regarded as appropriate in the past.

Miscellaneous Fees

The complainants proposed to reduce the AEP cost of service to reflect the revenues that MichCon Gathering collects through various fees, as indicated in records that came to light during discovery. As shown in Exhibit C-89, there are three categories of fee revenues: miscellaneous

revenues (including billings for contractual services), imbalance revenues based on prior month imbalances, and liquids revenues received from SWEPI. In addition, the complainants included interest income of \$394,000 per year, which is the average interest revenue recorded in MichCon Gathering's books during 1996-99.

The ALJ rejected an adjustment for miscellaneous fees and revenues. He found that the complainants had not shown that the various revenues were appropriately related to the AEP.

The complainants take exception to the ALJ's recommendation not to credit the miscellaneous fees and revenues. They argue that, by identifying the revenues and proposing an adjustment, they raised the issue and shifted the burden to the respondents to show that the revenues are in fact unrelated to the AEP operation. The complainants reiterate arguments (made in conjunction with the Goose Creek Compressor and other issues) regarding the ALJ's improper allocation of the burden of proof to them. They argue that the burden should shift to the party with exclusive access to the information necessary to resolve the issues. They claim that they were dependent upon the respondents' discovery responses to identify the revenues and present an adjustment based on them. The complainants say that the respondents have failed to deny the revenues or demonstrate that they are unrelated to the AEP.

The respondents argue that the complainants have the burden of proof with respect to the claims they make and that they have failed to establish an adequate factual foundation to meet that burden. The respondents say that the complainants did not raise the fee adjustment until their rebuttal testimony, depriving the respondents of an opportunity to respond in their rebuttal testimony. The respondents note that interest revenues appear in MichCon Gathering's 1998 income statement filed with the Staff, a copy of which the complainants introduced into the record as Exhibit C-74. They also claim that it is illogical to project interest on the basis of a historical

average if the Commission does reduce the AEP rate in this case. With respect to the miscellaneous revenues, the respondents explain that MichCon Gathering engages in other activities that are unrelated to the AEP. They question how MichCon Gathering could earn liquids revenues from SWEPI, given that the processing charges paid to SWEPI include a credit for the liquids.

As provided in R 460.17515, the complainants generally have the burden of proof with respect to matters constituting the basis of the complaint, which, in this case, means the appropriate rate to be charged prospectively. The complainants can meet the burden of going forward (or production) on issues affecting the rate by presenting a prima facie case demonstrating that the cost of service supports a lower rate, as they did by presenting evidence of miscellaneous revenues that were not otherwise reflected in the cost of service. July 9, 1987 order, Case No. U-8020-R at 16-17; see also December 7, 1989 order, Cases Nos. U-8678 et al. at 11. Unlike the burden of going forward, the ultimate burden of persuasion does not shift once a prima facie case is presented.¹⁸ The Commission reviews the evidence as a whole, as it relates to the issue, and makes its finding accordingly. See order, Case No. U-8020-R at 16-17.

These principles do not permit the respondents to rely on the complainants' lack of complete information regarding all details of the revenues to defeat the proposed adjustment. This is particularly true when the information necessary to supply missing details is within the exclusive control of the respondents and can only be obtained by the complainants, if at all, through discovery. An adverse inference may be drawn against a party that fails to produce evidence within its control. Grossheim v Associated Truck Lines, Inc., 181 Mich App 712, 715; 450 NW2d 40 (1989). Although it is not completely clear how the revenue items shown in Exhibit C-89 relate

¹⁸For a comprehensive explanation of how the burdens of going forward and persuasion relate to the burden of proof, see Kar v Hogan, 399 Mich 529, 539-40; 251 NW2d 77 (1976).

to the AEP, the respondents, who maintain internal records of MichCon Gathering's revenues, did not attempt to supply the missing context. Moreover, the respondents could have offered to provide the information as surrebuttal testimony, but they did not. Under the circumstances, it is fair to infer that the revenues in question did relate to the AEP and do reduce its reasonable cost of service.

However, the interest revenues present a somewhat different situation. As the respondents note, MichCon Gathering's reported interest was available to the complainants at the time that they filed their initial testimony. Because the record does not provide a reasonable basis for allocating the interest between AEP and non-AEP activities, the Commission will exclude the interest from the miscellaneous revenues adjustment proposed by the complainants.

Complainants' Motions to Strike

In their exceptions, the complainants argue that the ALJ should have granted their motions to strike testimony of the respondents' witnesses. Although the exceptions do not repeat in detail the reasons for the motions to strike, the testimony in question relates to several items of cost that the complainants had opposed as unrelated to the AEP's cost of service. This exception is moot in light of the findings in this order resolving the disputed issues. Moreover, it is not sufficient to claim that testimony is irrelevant because it seeks to recover additional costs that were not included in the rate approved in Case No. U-10547 or that the complainants opposed on other grounds.

Conclusion

As set forth in the computation in Appendix A, this order approves a prospective AEP rate of \$0.05104 per Mcf. As stipulated by the parties, the approved rate will become effective two calendar months prior to the date of this order.

The Commission FINDS that:

- a. Jurisdiction is pursuant to 1929 PA 9, as amended, MCL 483.101 et seq.; MSA 22.1311 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; MSA 22.1 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; MSA 22.13(1) et seq.; 1969 PA 165, as amended, MCL 483.151 et seq.; MSA 22.1332(1) et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; MSA 3.560(101) et seq.; and the Commission's Rules of Practice and Procedure, as amended, 1992 AACRS, R 460.17101 et seq.
- b. The request for retroactive rate relief stated in the complaint should be denied.
- c. An AEP transportation rate of \$0.05104 per Mcf, as set forth in Appendix A to this order, is reasonable and should be approved.
- d. The gas-in-kind retainage should be 0.12% of gas delivered by shippers to the AEP.
- e. MichCon Gathering should depreciate AEP facilities at a unit of production rate of \$0.01666 per Mcf, as set forth in Appendix B to this order.

THEREFORE, IT IS ORDERED that:

- A. The request for retroactive rate relief stated in the complaint is denied.
- B. MichCon Gathering Company is authorized to charge \$0.05104 per thousand cubic feet for the transportation of Antrim gas delivered to the Header system, effective two calendar months prior to the date of this order.
- C. The retainage percentage for Antrim gas is revised to 0.12%, effective two calendar months prior to the date of this order.

D. MichCon Gathering Company shall depreciate the Antrim Expansion Project assets at a unit of production rate of \$0.01666 per thousand cubic feet, until otherwise ordered by the Commission.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26; MSA 22.45.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ Laura Chappelle
Chairman

(S E A L)

/s/ David A. Svanda
Commissioner

/s/ Robert B. Nelson
Commissioner

By its action of July 11, 2001.

/s/ Dorothy Wideman
Its Executive Secretary

D. MichCon Gathering Company shall depreciate the Antrim Expansion Project assets at a unit of production rate of \$0.01666 per thousand cubic feet, until otherwise ordered by the Commission.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26; MSA 22.45.

MICHIGAN PUBLIC SERVICE COMMISSION

Chairman

Commissioner

Commissioner

By its action of July 11, 2001.

Its Executive Secretary

In the matter of the complaint of)
DOMINION MIDWEST ENERGY, INC.,)
DOMINION RESERVES, INC., MILLER ENERGY,)
INC., MUSKEGON DEVELOPMENT COMPANY,)
and **QUICKSILVER RESOURCES, INC.,** against)
MICHIGAN CONSOLIDATED GAS COMPANY,)
MICHCON GATHERING COMPANY, and)
MICHCON PIPELINE COMPANY.)
_____)

Case No. U-12342

Suggested Minute:

“Adopt and issue order dated July 11, 2001 granting relief on a complaint filed by Dominion Midwest Energy, Inc., and other producers of Antrim gas against MichCon Gathering Company and other affiliated companies and revising the transportation rate charged for Antrim gas from \$0.09 per Mcf to \$0.05104 per Mcf, as set forth in the order.”