

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. : Case No.
2000 Electric Operations : PU-399-01-186
Annual Report :

TRANSCRIPT OF
HEARING
VOLUME II

Taken At
State Capitol
Public Service Commission
Bismarck, North Dakota
February 26, 2002

BEFORE ALLEN C. HOBERG
-- PROCEDURAL HEARING OFFICER --

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25

A P P E A R A N C E S

COMMISSIONERS PRESENT:

COMMISSIONER SUSAN E. WEFALD
COMMISSIONER LEO M. REINBOLD
COMMISSIONER TONY CLARK

MR. WILLIAM W. BINEK
Public Service Commission
State Capitol
600 East Boulevard Avenue
Bismarck, North Dakota 58505-0480

FOR THE COMMISSION STAFF.

MR. WILLIAM P. PEARCE of
Pearce & Durick
Attorneys at Law
314 East Thayer Avenue
P.O. Box 400
Bismarck, North Dakota 58502-0400

-- and --

MR. DOUGLAS W. SCHULZ of
Montana-Dakota Utilities Co.
Attorney at Law
400 North Fourth Street
Bismarck, North Dakota 58502-4092

FOR MONTANA-DAKOTA
UTILITIES CO.

MR. PATRICK FAHN
Public Service Commission
State Capitol
600 East Boulevard Avenue
Bismarck, North Dakota 58505-0480

COMMISSION ADVISOR.

1	C O N T E N T S	
2		Page No.
3	Opening comments	271
	Motion to dismiss by Mr. Pearce	485
4	Resistance to above motion by Mr. Binek	486
	Discussion regarding proposed findings of	
5	fact, conclusions of law and order	486
	Closing comments by the Commissioners	489
6	-----	
7		
	CERTIFICATE OF COURT REPORTER	491
8	-----	
9		
	WITNESSES:	
10		
	Roger J. Schiffman	
11		
	Direct examination by Mr. Pearce	272
12	Cross-examination by Mr. Binek	306
	Examination by Mr. Fahn	318
13	Examination by Commissioner Wefald	323
	Examination by Commissioner Reinbold	337
14	Examination by Commissioner Clark	340
	Redirect examination by Mr. Pearce	341
15	Recross-examination by Mr. Binek	343
	Redirect examination by Mr. Pearce	345
16		
	Terry L. Blinsky	
17		
	Direct examination by Mr. Pearce	346
18	Cross-examination by Mr. Binek	358
	Examination by Commissioner Wefald	364
19	Redirect examination by Mr. Pearce	365
20		
	Douglass A. Mahowald	
21		
	Direct examination by Mr. Pearce	369
	Cross-examination by Mr. Binek	375
22	Examination by Mr. Fahn	382
	Examination by Commissioner Wefald	384
23	Examination by Commissioner Reinbold	391
	Examination by Commissioner Clark	392
24	Further examination by Commissioner	
	Wefald	394
25	Redirect examination by Mr. Pearce	394
	Recross-examination by Mr. Binek	396

1	C O N T E N T S (Continued)				
2	Douglass A. Mahowald (Continued)				
3	Further examination by Commissioner				
4	Wefald			400	
5	Richard A. Espeland				
6	Direct examination by Mr. Pearce			407	
7	Cross-examination by Mr. Binek			417	
8	Examination by Mr. Fahn			425	
9	Examination by Commissioner Clark			426	
10	Examination by Commissioner Wefald			428	
11	Recross-examination by Mr. Binek			429	
12	Donald R. Ball				
13	Direct examination by Mr. Pearce			430	
14	Cross-examination by Mr. Binek			442	
15	Examination by Commissioner Wefald			446	
16	Examination by Commissioner Clark			449	
17	Redirect examination by Mr. Pearce			452	
18	Recross-examination by Mr. Binek			460	
19	Further examination by Commissioner				
20	Wefald			468	
21	Further examination by Commissioner				
22	Clark			471	
23	Redirect examination by Mr. Pearce			474	
24	Rita A. Mulkern				
25	Direct examination by Mr. Pearce			475	
26	Cross-examination by Mr. Binek			479	
27	Examination by Commissioner Wefald			480	
28	-----				
29	EXHIBITS:				
30	No.	Description	M	O	R
31	15	Table 1, Completed and Sited			
32		New Power Plants in MAPP	271	302	302
33	-----				
34					
35					

1 (The following proceedings were had and
2 made of record herein, commencing at 8:33 a.m.,
3 Tuesday, the 26th day of February, 2002:)

4 (Exhibit 15 was marked for
5 identification.)

6 MR. HOBERG: It's February 26th in the
7 year 2002. This is the second day in the hearing
8 of the matter of the North Dakota Public Service
9 Commission Staff complaint regarding Montana-Dakota
10 Utility Company and its year 2000 electric
11 operations annual report.

12 Yesterday we completed the presentation of
13 the state's case, the PSC staff's case, and we were
14 on the -- we completed the second witness of MDU's
15 case, about to take the third witness.

16 Are there any preliminary matters we need
17 to discuss before we go into the evidentiary
18 portion of the hearing again? Commissioners, any
19 preliminary matters that you have?

20 COMMISSIONER REINBOLD: Nothing.

21 MR. HOBERG: Mr. Binek?

22 MR. BINEK: Nothing I'm aware of.

23 MR. HOBERG: Mr. Pearce?

24 MR. PEARCE: No.

25 MR. HOBERG: Would you call your next

1 witness, please.

2 MR. PEARCE: I call Roger Joseph
3 Schiffman.

4 MR. HOBERG: Okay. For the benefit of Mr.
5 Schiffman and all the other witnesses who will be
6 testifying today, I'll give the admonition I'm
7 required to give by law, and that is that the
8 maximum penalty for perjury in this state is a
9 Class C Felony, punishable by a maximum 5 years
10 imprisonment, \$5,000 fine, or both.

11 (Witness sworn.)

12 MR. HOBERG: Thank you. Mr. Pearce,
13 please.

14 ROGER J. SCHIFFMAN,
15 having been first duly sworn, was examined and
16 testified as follows:

17 DIRECT EXAMINATION

18 BY MR. PEARCE:

19 Q. Would you please state your name, your
20 business address and your position?

21 A. Yes. My name is Roger Joseph Schiffman.
22 My business address is 3100 Zinfandel Drive, Suite
23 600, Rancho Cordova, California, 95760. I'm a
24 principal consultant in the Energy and Water
25 Practice of Navigant Consulting, Incorporated.

1 Q. Would you please describe NCI's business
2 and your role and responsibilities?

3 A. NCI's a national management consulting
4 firm specializing in the energy industry. The
5 Energy and Water Practice provides services to all
6 segments of the restructured energy industry and is
7 a leading provider of planning and engineering
8 services to the water industry.

9 MR. HOBERG: Excuse me, Mr. Schiffman.
10 Could you maybe move the mike in front of you a
11 little bit? I'm having a little trouble hearing
12 you over here.

13 THE WITNESS: Sure. Our existing energy
14 sector client base includes most of the largest
15 utilities in the United States, most of the
16 independent power producers, and a number of
17 municipal utilities. NCI is active in all North
18 American electricity markets.

19 Within NCI, I manage a group that focuses
20 on electricity market assessment and analysis. My
21 first exhibit lists my detailed experience. One of
22 the key services provided by my group centers on
23 wholesale electricity market price forecasts
24 derived using detailed computer simulation models.

25 Within the last four years I have prepared

1 forecasts of electricity market prices in all North
2 American regional markets, including the
3 Mid-Continent Area Power Pool. These forecasts
4 have been used by consulting clients for several
5 purposes, including supply portfolio planning and
6 procurement, contract evaluation, asset valuation,
7 and feasibility analysis.

8 A number of the forecasts have also been
9 used to support revenue projections underlying
10 project financing deals for new merchant power
11 plants.

12 Within the last year I have also been
13 heavily involved in NCI's engagement with the
14 California Department of Water Resources in that
15 agency's efforts to structure a portfolio of power
16 supply contracts and to obtain a targeted 13
17 billion dollars in new financing. Preparation of
18 detailed forecasts requires constant attention to
19 supply and demand fundamentals in each of the North
20 American market regions, in addition to careful
21 evaluation of regulatory and market developments.

22 Q. Would you please describe your
23 professional experience before joining NCI?

24 A. From 1998 through March 2000 I was
25 employed as a senior consultant by Henwood Energy

1 Services. My duties at HESI were similar to those
2 at NCI and included electricity market assessment,
3 electricity market price forecasting, generating
4 assets valuation, gathering market analysis and
5 intelligence, and completing a variety of financial
6 and cost evaluation projects for consulting
7 clients.

8 From 1990 through '98 I was employed as a
9 financial analyst at the Public Service Commission
10 of Wisconsin. My job responsibilities included
11 policy development and analysis, economic and cost
12 analysis, evaluation of competitively bid power
13 supply proposals, integrated resource planning,
14 advising the Wisconsin Commission on rate of return
15 and capital structure, and conducting specialized
16 studies concerning public utility finance,
17 economics and regulatory policy.

18 Q. Would you please describe your educational
19 background?

20 A. I earned a Bachelor of business
21 administration in finance, investment and banking
22 from the University of Wisconsin-Madison in 1988.
23 From 1988 through 1990 I engaged in graduate
24 studies in finance also at the University of
25 Wisconsin-Madison.

1 Q. And on whose behalf are you testifying
2 this morning?

3 A. I am testifying on behalf of
4 Montana-Dakota Utilities, a division of MDU
5 Resources Group, Incorporated.

6 Q. What is the purpose of your testimony?

7 A. I will address wholesale bulk power market
8 conditions over the past several years as well as
9 the outlook for 2000 and more specifically the
10 impact of those conditions on the level and
11 profitability of Montana-Dakota's off-system sales.
12 While many of these conditions are common across
13 the United States, I will also address the
14 conditions in the market that Montana-Dakota sells
15 into, which is the MAPP region.

16 Q. And what are your conclusions?

17 A. Staff witness, Mike Diller, proposes that
18 the level of off-system sales margins experienced
19 in 2000 be reflected in rates that will be in
20 effect in 2002 and beyond. However, 2001 was
21 hardly a normal or average year in any respect, and
22 conditions in both natural gas and electricity
23 wholesale markets changed in very significant ways
24 throughout the year. As in all competitive
25 markets, the fundamental demand and supply

1 conditions explained the 2000 to 2001 experience
2 and define the outlook for 2002.

3 Q. What are the primary determining factors
4 of Montana-Dakota's off-system sales revenues?

5 A. In simple terms, Montana-Dakota's margins
6 from off-system sales are determined by the level
7 or quantity of sales and the profit margin, which
8 is revenue minus cost, that it's able to obtain
9 from each sale.

10 The opportunity to make off-system sales
11 is created by the gap between the price of
12 purchases and sales opportunities in the spot
13 market in Montana-Dakota's cost of powering its own
14 generating units, which are primarily coal fired.

15 Spot market prices in the MAPP region
16 where Montana-Dakota operates can vary
17 substantially with the price of natural gas and
18 with the fuel efficiency of units on the margin.
19 For Montana-Dakota to make a profitable sale the
20 gap, or profit margin, must be sufficient to offset
21 incremental operating costs and to provide adequate
22 incentive to increase production levels and to
23 compensate for any risk associated with the
24 transaction. Thus, the profit margin is the
25 primary determinant of the quantity of off-system

1 sales that Montana-Dakota is able to make in a
2 given period.

3 The margins that Montana-Dakota is able to
4 obtain are determined by the size of this fuel cost
5 differential as well as fundamental demand and
6 supply conditions that affect the markets that
7 Montana-Dakota is able to reach. Demand and supply
8 conditions are important because the so-called
9 spark spread, the difference between wholesale
10 electricity and natural gas prices, will vary in
11 response to changing demand and supply conditions.

12 Q. What markets does Montana-Dakota sell
13 into?

14 A. Montana-Dakota sells primarily into Upper
15 Midwest wholesale markets in the MAPP, MAIN and
16 Southwest Power Pool regions. The northern MAPP
17 region where Montana-Dakota's generators are
18 located can be characterized as a relatively low-
19 cost market. Trade patterns in the Upper Midwest
20 are such that energy tends to flow from the
21 northern and western MAPP region toward higher cost
22 markets in eastern MAPP, MAIN and SPP.

23 MAPP power markets are sometimes impacted
24 by transmission constraints which limit export
25 opportunities, particularly the amount of energy

1 that can flow simultaneously in the easterly
2 direction toward the Wisconsin Upper Michigan
3 Systems subregion of MAIN, and in the southerly
4 direction toward the St. Louis area.

5 Q. What factors do you consider important
6 when comparing wholesale power market conditions
7 from year to year?

8 A. Wholesale power markets operate in a
9 competitive landscape where numerous influences
10 combine to create changes in the market
11 environment. Weather, fuel prices, economic
12 growth, generation mix, and the supply demand
13 balance all play important roles in defining trends
14 in the broader wholesale power markets.

15 Indeed, these are all important
16 quantitative inputs in the complex computer models
17 many companies use to forecast power pricing and
18 are critical factors in real-time market
19 operations.

20 Q. How have fundamental market conditions
21 evolved in North America power markets over recent
22 years?

23 A. U.S. wholesale power markets have
24 undergone significant evolution in recent years in
25 response to deregulation policies implemented in a

1 number of states and in response to continued
2 efforts by the Federal Energy Regulatory Commission
3 to establish fair and open transmission access.
4 The extent of market reforms has varied by region.

5 During this period of transition toward
6 competitive markets, wholesale electricity prices
7 have exhibited considerable volatility. The levels
8 of price volatility have also varied by region and
9 have sometimes resulted primarily from rapidly
10 changing supply and demand conditions.

11 In some circumstances the levels of
12 volatility witnessed in regional markets have also
13 been due to the temporal exercise of market power
14 by suppliers or due to institutional inefficiencies
15 in organizations and market rules meant to regulate
16 market operations in a particular region.

17 Q. Would you please expand on the experience
18 of price volatility in the Midwest region?

19 A. During the summer of 1998 and 1999
20 significant price volatility was first seen in
21 Midwest power markets. Several fundamental supply
22 conditions contributed to the price volatility seen
23 in that period. In the early to mid 1990s
24 development of new generating supply had lagged in
25 many Midwest markets as the future role of

1 investor-owned utilities in the generation market
2 became uncertain with the advance of deregulation.

3 With uncertainty over which entities would
4 be responsible for serving native load customers
5 and significant risks of stranded cost exposure in
6 the face of declining demand levels, utility
7 companies and their investors became reluctant to
8 make large investments in new capital-intensive
9 power plants. As such, demand growth during that
10 period outpaced growth in the supply base in many
11 regions.

12 Beginning in late 1997, several nuclear
13 plants in the Upper Midwest region faced extended
14 outages to repair cracks that surfaced in steam
15 generators. At the same time the Nuclear Energy
16 Regulatory Commission began a rigorous review of
17 its safety regulations governing nuclear plant
18 operation.

19 The combination of physical repairs and
20 more stringent safety regulations resulted in
21 extended outages of an unprecedented amount of
22 Midwest nuclear capacity during the summer of 1998
23 and 1999.

24 Those supply conditions were further
25 exacerbated when similar concerns with safety

1 compliance forced several nuclear plants in
2 Ontario, Canada, into extended outage. That net
3 result was critical supply shortages in the Upper
4 Midwest during that period with over 7,000
5 megawatts of nuclear capacity out of service in the
6 Midwest and an additional 5,000 megawatts of
7 nuclear capacity out of service in Ontario.

8 Those outages led to significant price
9 volatility during the summer months. At their
10 peak, reported wholesale power prices reached \$1250
11 per megawatt-hour in July 1998 and \$1426 per
12 megawatt-hour in July 1999 in the MAPP region.

13 With return to service of the nuclear
14 capacity in the MAIN and ECAR regions and
15 additional generating supply coming into Midwest
16 prices -- or into Midwest markets, price volatility
17 returned to more normal levels during 2000.

18 Q. What fundamental market conditions
19 occurred during 2001 that indicate it was an
20 abnormal year?

21 A. As discussed by Mr. Blinsky, Mr. Wilkinson
22 and Mr. Gaske, the key factor underlying
23 electricity market dynamics in 2001 concerned the
24 unprecedented increase in natural gas price
25 witnessed during the last quarter of 2000 and the

1 first two quarters of 2001. During that period,
2 high natural gas prices resulted in significantly
3 increased spot market electricity prices throughout
4 the United States. That pattern is illustrated in
5 Mr. Wilkinson's Exhibit PLW-1.

6 Within the MAPP region natural gas fuel
7 generators have been playing an increasingly
8 prominent role in establishing spot market clearing
9 prices. This pattern occurs because a significant
10 portion of new entry in MAPP has been fueled by
11 natural gas, and those new resources operate as
12 intermediate and peaking resources. Gas-fired
13 generators in MAPP now occupy an expanding segment
14 of the supply curve that represent the marginal
15 resource with increasing frequency.

16 The correlation between MAPP electricity
17 and natural gas prices has been increasing in
18 recent years due to this factor and will continue
19 to strengthen as gas-fired resources represent an
20 expanding portion of generating supply.

21 In addition to the run-up in natural gas
22 prices seen in late 2000 and the first half of
23 2001, the supply crisis in western U.S. power
24 markets, and particularly in California, also
25 played an important role in electricity price

1 discovery in other U.S. markets.

2 While the power systems in the eastern and
3 midwest U.S. operate asynchronously to those in the
4 western U.S., the level of sustained abnormal
5 prices seen in California had an impact on price
6 discovery in all domestic power markets. The
7 extent of the crisis that arose in California was
8 beyond anyone's expectations and drew significant
9 attention throughout the world.

10 From a risk management perspective, market
11 participants in all market regions were required to
12 reevaluate their hedging strategies in response to
13 the magnitude of prices and reliability
14 difficulties seen in California. The financial
15 distress faced by the California investor-owned
16 utilities were also factors that far exceeded prior
17 expectations.

18 The supply crisis reached a level so
19 serious that the State of California was required
20 to step in and assume the role of spot market
21 broker and financier. Absent that step, frequent
22 and sustained blackout periods would have occurred
23 during the first half of 2001 and perhaps
24 throughout the year. A crisis of that magnitude
25 was clearly an abnormal event.

1 Q. What steps did energy market participants
2 take in response to increased natural gas price
3 levels and in response to market uncertainties
4 created by the supply crisis in California?

5 A. Market participants that faced significant
6 price risk in electricity and natural gas spot
7 markets early in 2001 took actions to mitigate a
8 portion of that risk on a going-forward basis. In
9 the short-term, risk mitigation measures involved
10 entering into short-term or intermediate-term
11 bilateral contracts designed to create improved
12 price certainty and to hedge against extreme upside
13 price volatility. This type of hedging activity
14 was a rational response to extreme uncertainties in
15 both natural gas and electricity markets.

16 Because of the level of volatility seen in
17 both natural gas and power markets during late 2000
18 and early 2001, the risk premiums underlying such
19 hedging arrangements were quite high by historical
20 standards.

21 A concrete example of the hedging activity
22 I am describing is illustrated in Mr. Blinsky's
23 surrebuttal testimony and has direct relevance to
24 projecting the margin on Montana-Dakota's
25 off-system sales.

1 As described in Mr. Blinsky's testimony,
2 Montana-Dakota entered into a sales agreement in
3 March of 2001 which locked in summer electricity
4 prices and sales revenue based on the prices of
5 futures contracts in place at that time. When spot
6 market natural gas and electricity prices declined
7 during the last half of the year, Montana-Dakota
8 enjoyed a higher profit margin based on its
9 contracting position than it would have earned
10 selling power directly at spot market prize.

11 Under current market conditions
12 contracting opportunities such as that enjoyed by
13 Montana-Dakota are no longer available because the
14 premium between contract and spot market prices is
15 substantially smaller.

16 Q. What impact have these fundamental energy
17 market conditions had on market prices in late 2000
18 and 2001?

19 A. The price spikes we observed recently in
20 the winter of 2000-2001 were clearly an anomaly.
21 In fact, winter peak wholesale power prices have
22 historically varied between 25 and \$35 per
23 megawatt-hour and had only ever reached around \$40
24 per megawatt-hour in the winter of 1999-2000.

25 With higher natural gas prices and greater

1 market uncertainty, wholesale power prices in MAPP
2 reached \$142 per megawatt-hour during the on-peak
3 period of December 12, 2000. This level was, in
4 fact, higher than the previous and following summer
5 peaks of \$120 per megawatt-hour reached in August
6 2000 and August 2001, respectively.

7 Off-peak pricing also increased during the
8 winter of 2000 to 2001, reaching slightly more than
9 \$47 per megawatt-hour for the first time in recent
10 history. Normally, off-peak pricing in MAPP runs
11 between 10 and \$15 per megawatt-hour.

12 Since natural gas resources are really
13 marginal in the MAPP region during off-peak
14 periods, this level of off-peak prices suggests
15 significant risk premiums being priced into
16 wholesale electricity prices. Exhibit RJS-2
17 illustrates daily spot market electricity prices in
18 the MAPP region for the period beginning January
19 1996 through February 2002.

20 Q. How have the electricity price levels seen
21 in late 2000 and the first half of 2001 impacted
22 the margin earned on off-system sales by
23 Montana-Dakota during that period?

24 A. With continued coal price stability, the
25 run-up in natural gas prices and risk premiums

1 priced into short-term and intermediate-term
2 bilateral transactions resulted in abnormally high
3 profit margins for coal-fired generators throughout
4 the first months of 2001.

5 That pattern can be seen in Exhibit RJS-3,
6 where daily coal-based and natural gas-based spark
7 spreads were plotted for the period January 1996
8 through February 2002. Exhibit RJS-4 plots the
9 spark spread data on a monthly basis for the same
10 period, while Exhibit RJS-5 plots the same monthly
11 spark spread data for just the period January 2000
12 through February 2002.

13 The spark spread represents the margin
14 above fuel costs achievable by operation of a given
15 power plant. In estimating the spark spread, we
16 have assumed market heat rates of 7,000 Btus per
17 kilowatt-hour for gas-fired generation and 12,000
18 Btus per kilowatt-hour for coal-fired generators.

19 The coal-based spark spread measure
20 provides a representation of the margin that
21 Montana-Dakota could be expected to earn on
22 off-system sales but does not net out additional
23 costs attributed to nonfuel operations and
24 maintenance. As shown in Exhibit RJS-4 and Exhibit
25 RJS-5, the coal-based spark spread departs

1 significantly from the natural gas-based spark
2 spread during the period of high natural gas prices
3 experienced in the fourth quarter of 2000 and in
4 the first half of 2001.

5 During the last half of 2001 and the first
6 two months of 2002 when natural gas prices returned
7 to equilibrium levels, the two spark spread
8 measures returned to their normal historical
9 pattern and tracked each other closely.

10 The abnormal departure of coal-based and
11 natural gas-based spark spreads illustrated in
12 Exhibit RJS-5 directly corresponds with the period
13 of abnormally high margins and off-system sales
14 enjoyed by Montana-Dakota during 2001. As shown in
15 this exhibit, coal- and natural gas-based spark
16 spreads track each other very closely throughout
17 the second half of 2001.

18 Q. Are current natural gas and electricity
19 market fundamentals such that you would expect
20 repeated electricity price spikes and continued
21 abnormally high profit levels on Montana-Dakota's
22 off-system sales?

23 A. No. Market fundamentals for 2002 and
24 subsequent near-term years suggest a period of
25 improved stability in wholesale power markets. As

1 discussed by Mr. Blinsky, Mr. Wilkinson and Mr.
2 Gaske, natural gas prices have returned to more
3 normal levels, and the current outlook is for
4 natural gas price stability.

5 In wholesale electricity markets, a
6 combination of new supply coming on-line, reduced
7 demand from target and conservation programs, and
8 institutional market reforms have contributed to
9 price stability again in the western U.S. market.
10 That stability has been bolstered by a return to
11 normal or perhaps wet-year hydro conditions in the
12 western U.S. and by the increased use of bilateral
13 contracts entered into to hedge against upward
14 price volatility.

15 In Midwest power markets supply expansion
16 is also expected to improve supply demand margins
17 and to contribute to electricity price stability.
18 Exhibit RJS-6 lists estimated historical and 2002
19 projected reserve margin levels in the MAPP, MAIN
20 and SPP market regions. As shown, reserve levels
21 reached their floor during 1999 and 2000 and are
22 projected to continue their rebound during 2002.

23 This combination of factors points to
24 lower and more stable wholesale electricity prices
25 in the MAPP region for 2002 compared to the price

1 and volatility levels seen over the last four years
2 and particularly during the first half of 2001.

3 As discussed by Mr. Blinsky, this
4 expectation of reduced-price volatility is
5 reflected in current market expectations and prices
6 of NYMEX futures contracts for on-peak power
7 delivered into the energy hub. Buyers and sellers
8 in futures markets place great weight on their
9 fundamental supply and demand issues.

10 Q. Given your expectation of likely 2002
11 wholesale power market conditions in the Midwest
12 region, do you believe Montana-Dakota will enjoy
13 profit margins on off-system sales that are
14 comparable to the levels earned during 2001?

15 A. No. With lower and more stable natural
16 gas and electricity prices, profit margins on
17 off-system sales will be correspondingly lower.
18 Reduced price volatility will result in lower risk
19 premiums being priced into wholesale market
20 transactions.

21 In addition, as supply expands and supply
22 demand balances improve, Montana-Dakota will face
23 greater competition for off-system sales. With
24 lagging electricity sales due to the current
25 economic downturn, that competition will only be

1 greater and Montana-Dakota might face reduced
2 volumes of off-system sales, in addition to lower
3 profit margins on those sales.

4 As discussed above, natural gas and
5 electricity price volatility created the increased
6 margins for Montana-Dakota in the winter of 2000-
7 2001 because Montana-Dakota retained its relatively
8 flat cost structure relative to natural gas-burning
9 competitors. With more stable prices going
10 forward, the margins available in off-system sales
11 will be lower.

12 In summary market conditions toward the
13 end of 2001 are significantly more representative
14 of what can be expected in 2002 and for the
15 foreseeable future.

16 Q. Do you believe that the approach used by
17 Mr. Blinsky for forecasting margin on off-system
18 sales is reasonable?

19 A. Yes. I believe Mr. Blinsky uses a
20 reasonable approach. Forecasting energy market
21 prices is always a difficult exercise, and using
22 the prices of currently traded futures contracts is
23 a reasonable way to assess current market
24 expectations of spot market prices that will
25 prevail during the relevant months of 2002.

1 Q. Showing you what's been marked as Exhibit
2 9, Mr. Schiffman, would you identify what that is
3 and explain what it shows?

4 A. Yes. Given some of the -- some of the
5 questions that have been raised about the NYMEX
6 futures contracts and the role that they play in
7 forecasting forward prices, we also took a look at
8 alternative sources of forward electricity prices,
9 which came from the Intercontinental Exchange,
10 which is an exchange that's been in place for maybe
11 two years and records bilateral transactions and
12 bid-and-offer prices between entities in the power
13 markets.

14 We put this in as an alternative look at
15 what the forward curve is like. Exhibit 9 lists
16 the prices from the Intercontinental Exchange as of
17 February 16th, 2002. You'll see that the prices
18 are roughly comparable, maybe slightly lower than
19 what was listed in Mr. Blinsky's exhibit from the
20 February 16th NYMEX futures contracts quotes.
21 These are both for delivery at the Cinergy hub, and
22 as I understand it, Mr. Blinsky will be presenting
23 an updated view of the off-system sales margins
24 based on this curve, as well, for the Commission's
25 consideration.

1 Q. Would you for purposes of clarification
2 just remind us what's meant by the Cinergy trading
3 hub?

4 A. That's -- Cinergy is located in the Ohio,
5 Indiana region. It's one of the places that
6 participants in the electricity markets have chosen
7 to price their transactions against as sort of an
8 index, and so the prices here are for delivery at
9 that location.

10 Q. And that's a widely used reference in the
11 industry, isn't it?

12 A. Yes.

13 Q. Did you prepare Exhibit 9, Mr. Schiffman?

14 A. Yes.

15 Q. And to the best of your information and
16 belief, are the data in Exhibit 9 true and correct?

17 A. Yes, they are.

18 MR. PEARCE: I will offer Exhibit 9.

19 MR. HOBERG: Any objection, Mr. Binek?

20 MR. BINEK: No objection.

21 MR. HOBERG: Okay. Exhibit 9 is admitted.

22 Q. (MR. PEARCE CONTINUING) Mr. Schiffman,
23 I've handed you also Exhibit 11, which is already
24 in evidence, and Exhibit 13 and Exhibit 15.
25 Exhibit 11 is the NERC report that's been admitted

1 into evidence, I believe it's a two-page report.
2 Exhibit 13 is a longer MAPP report that we will be
3 having you testify to, and Exhibit 15 is an
4 additional -- several additional schedules that
5 were not included in your prefiled direct
6 testimony. Would you comment on --

7 MR. HOBERG: Do you mean his surrebuttal?
8 I don't think he had direct, did he?

9 MR. PEARCE: I'm sorry. I called it
10 direct. Surrebuttal, yes.

11 Q. (MR. PEARCE CONTINUING) Would you -- the
12 exhibits -- well, all of these exhibits relate, I
13 believe, to generation and generation capacity in
14 the MAPP region. Would you comment on these
15 exhibits and discuss what they show, if you would?

16 A. Yeah. I prepared these exhibits in
17 response to Exhibit 11, which had provided a little
18 bit of confusion for me because of the amounts of
19 new capacity that they have listed in there as
20 likely to come into the MAPP market in the 2001 to
21 2010 time frame.

22 They're indicating in Exhibit 11 that
23 there will be an additional 5,108 megawatts of
24 capacity during that period, from 2001 through
25 2010, and this again was a report from the North

1 American Electric Reliability Council.

2 Exhibit 13 is a different report that's
3 published by MAPP itself, and the focus of it is on
4 transmission planning, and they've got a list of
5 projects, new generating projects under development
6 in the MAPP region. Within that report --

7 MR. BINEK: Your Honor?

8 MR. HOBERG: Yes.

9 MR. BINEK: I don't have a copy of Exhibit
10 13.

11 MR. PEARCE: Oh, I'm sorry. I thought I
12 had furnished them.

13 MR. HOBERG: I thought he had, too.

14 MR. PEARCE: Does the Commission have 13?

15 MR. HOBERG: No, I don't think they do.

16 COMMISSIONER REINBOLD: Do we want them?

17 MR. PEARCE: It doesn't talk about
18 recession. Well, maybe it does indirectly.

19 MR. HOBERG: This is Exhibit 13.

20 MR. PEARCE: 13.

21 Q. (MR. PEARCE CONTINUING) Would you go
22 ahead?

23 A. Yeah. Beginning -- it's at table 2.4
24 beginning on page 14. They go through quite an
25 extensive list of new power plants that have either

1 entered the MAPP market or that are under
2 development in the MAPP market as of the date of
3 this -- of the preparation of that report, which
4 was November 30th of 2001.

5 What I've done in Exhibit 15 is identified
6 the plants that are just in the MAPP region because
7 in the report itself there are some that also
8 targeted for MAIN, and I've tried to -- to then add
9 those up and reconcile the differences in capacity,
10 because the amount of capacity that is shown in
11 Exhibit 13 is significantly higher than the amount
12 of new capacity that's shown in Exhibit 11 by --
13 it's roughly twice the amount by the 2010 time
14 frame, and most of it occurs in the early time
15 frame.

16 What appears to be going on is just that
17 the reliability councils themselves have been
18 having a lot of difficulty with their reliability
19 assessments in the last four or five years as the
20 markets have evolved and the planning
21 responsibility for new generation has become less
22 clear.

23 I think if you looked at these reports
24 maybe three or four years ago, they would show huge
25 capacity surpluses when the utilities were

1 following kind of their traditional history of
2 putting in plant resources to meet in MAPP, for
3 example, the 15 percent reserve margin target.

4 That created kind of a disconnect because
5 they would put the resources into the reliability
6 reports, but they weren't taking any active steps
7 to actually procure the new supply. So the reports
8 would keep coming out showing adequate resources,
9 but there was no generation under development,
10 which is part of what led to some of the supply
11 crises we had in the late 1990s.

12 So then through time, the utilities
13 stopped basically putting in resources unless they
14 were under development, and most of the new
15 projects that were coming in were either being
16 developed as merchant power plants or were being
17 developed without a purchase contract connection
18 with the IOU, so it wasn't clear who was
19 responsible and how much capacity was coming in.

20 So the reliability councils in recent
21 years have been having a lot of difficulty
22 struggling with the issue of how much new capacity
23 to include in their reliability assessments.

24 The reconciliation of these two reports,
25 it seems to be, that the MAPP region itself has a

1 list of generators that are under development, some
2 of which have come into the market, some of which
3 have -- have been going through permitting and
4 planning and siting and have sites identified, and
5 they're including a greater amount of new capacity
6 in, for example, their transmission planning report
7 than what NERC is including as new capacity in
8 their reliability assessment.

9 If you look at Exhibit 15 on, I guess,
10 table one, page three, if you look over to the far
11 right side, you'll see at 2005 there's 6500
12 megawatts of new capacity listed in the MAPP report
13 as likely to come into the markets by 2005, and
14 that's a greater amount than the whole period
15 listed in the NERC report.

16 The difference is kind of illustrated --
17 or the amounts of capacity in the MAPP report are
18 listed on what I've labeled as Exhibit RJS-10,
19 figure 1, where it shows graphically the three
20 different categories of new power plants that MAPP
21 has identified and the amounts completed and
22 unsited, which are the first two bars in the chart.
23 You'll see that it's about 6,000 megawatts by 2005,
24 and that looks like about 7,000 megawatts by 2010
25 if you don't include the unsited generation. If

1 you include the unsited generation, it's in excess
2 of 10,000 megawatts by 2010.

3 The last -- the last schedule in Exhibit
4 15 compares the forecast to demand in the most
5 recent MAPP EI-411 report. It lists in the second
6 column the change in demand that's projected, and
7 then it lists side-by-side projected changes in new
8 generation that are listed in again Exhibit 13 and
9 indicates in there that the generation additions
10 are projected to outstrip the demand growth.

11 So I put this in really just for the
12 Commissioners' information, to illustrate that
13 there seems to be some uncertainty. I think
14 Commissioner Wefald yesterday was concerned that we
15 were headed for supply deficits, which whether or
16 not that's true, I don't personally believe it's
17 true because, you know, the MAPP region has pretty
18 stringent penalties for not hitting their reserve
19 targets. The utilities are actively developing new
20 projects.

21 There's some uncertainty, I guess, about
22 how many of the new projects that are at some stage
23 of development are actually likely to come into the
24 market, and these two reports seem to take quite a
25 different view of that, you know, which is somewhat

1 odd given that they come out of primarily the same
2 entities or organizations.

3 The other point I would make is, you know,
4 there's a fair amount of capacity in these
5 schedules also that's listed as unsited. If you
6 look at what I've labeled -- again in Exhibit 15,
7 what I've labeled inside of that as Exhibit RJS-9,
8 this is the source of capacity that's listed as not
9 being sited in the MAPP transmission planning
10 report. Normally that type of capacity would not
11 be counted. People would look at it as, well, they
12 haven't really identified a site so we won't pay
13 any attention to it.

14 The reason in this instance that I would
15 pay some attention to it is you'll see that there's
16 a number -- the ones listed in here as various RFPs
17 by Xcel are essentially capacity that NSP is
18 scheduled to go out and procure through its regular
19 RFP process and bidding process that's been
20 approved by the Minnesota Commission, and so I
21 think a number -- or an amount of that capacity is
22 likely to be real capacity. It's just that they
23 haven't identified who the winning birds are at
24 this stage.

25 Q. Mr. Schiffman, did you prepare Exhibit 15?

1 A. Yes, I did.

2 Q. And to the best of your information and
3 belief are the data in that exhibit true and
4 correct?

5 A. Yes.

6 Q. And Exhibit 13 you took from a regular
7 printed material in the normal course of MAPP
8 business; is that right?

9 A. Yes. I just downloaded that report from
10 the MAPP web site.

11 MR. PEARCE: I'll offer Exhibits 13 and
12 15.

13 MR. BINEK: No objection.

14 MR. HOBERG: Exhibits 13 and 15 are
15 admitted.

16 Q. (MR. PEARCE CONTINUING) Finally, Mr.
17 Schiffman, would you elaborate somewhat on the
18 correlation between electricity and natural gas
19 prices in the MAPP market?

20 A. Yes. The -- there's been a number of
21 questions raised about the relationship between
22 electricity prices and natural gas prices I guess
23 in power markets in general and in the MAPP region
24 in particular. The -- maybe the primary idea to
25 take away from that discussion is that the

1 correlation between power prices and gas prices is
2 increasing in MAPP.

3 The reason for that is that there was not
4 a significant portion of gas-fired generation in
5 the MAPP market, say, four, five years ago. It was
6 basically with the additional capacity additions,
7 the portion of resources that burn natural gas or
8 are fueled by natural gas has been increasing in
9 the last four, five years and will increase through
10 time, at least with the current outlook, because
11 all of the new generation that's coming into the
12 market is gas-fired.

13 Similarly, a lot of the wholesale prices
14 that are seen in MAPP and are experienced by
15 Montana-Dakota in their off-system sales
16 opportunities are influenced by the supply
17 characteristics and the demand characteristics in
18 other markets, particularly the markets that occur
19 in northern Indiana -- or northern Illinois, in
20 Wisconsin, in the St. Louis area, and the supply
21 characteristics in those regions historically have
22 been more influenced by natural gas, particularly
23 in the Illinois and Ohio and Indiana regions
24 because there's always been a greater portion of
25 gas-fired capacity that is in those markets and

1 that in turn influences those markets from power
2 plants in the southeast United States.

3 Similarly, to MAPP only more drastically,
4 there's been a lot of gas-fired capacity that's
5 come into the MAIN region in the Chicago area and
6 northern Illinois area and into the ECAR region in
7 recent years.

8 So basically through time in recent years
9 the correlation has been increasing, and in future
10 periods it will increase even more drastically.

11 The other thing that's tricky about it,
12 though, is the correlation is basically very high
13 at times when gas-fired resources are setting the
14 marginal price, and by setting the marginal price
15 that just means that the people that are bidding at
16 a given hour for -- to sell their output and where
17 they're finding buyers in that hour, they tend to
18 be using similar technologies, so that most of the
19 resources will be gas-fired in a particular hour
20 primarily during the on-peak periods. In off-peak
21 periods gases are rarely marginal so there's not
22 much correlation in the MAPP prices between coal
23 and natural gas.

24 But then the other element is that the
25 correlation isn't just a constant. It varies by

1 season. So in the winter months and in the summer
2 months the correlation of electricity prices and
3 natural gas prices will be much higher just because
4 there's a greater reliance on the gas-fired
5 resources as demand levels are higher.

6 Q. Finally, Mr. Schiffman, turning back to
7 Exhibit 9 for a moment, which was your table on the
8 NYMEX and Intercontinental Exchange prices, showing
9 the differences, based on the last column in that
10 exhibit, your difference between the two prices,
11 would you anticipate that a projection of futures
12 prices using the Intercontinental Exchange figures
13 would come to about the same result that Mr.
14 Blinsky reached using the NYMEX futures?

15 A. Yes. I think it would be roughly the
16 same, and as I indicated, I think Mr. Blinsky has
17 an update of that for the Commission's
18 consideration.

19 MR. PEARCE: Thank you. That's all I
20 have.

21 MR. HOBERG: Thank you, Mr. Pearce. Just
22 for the record, Mr. Schiffman's surrebuttal
23 testimony is found in Exhibit 7, and it's Docket
24 No. 61 in the PSC docket. Mr. Binek, do you have
25 any questions of Mr. Schiffman, please?

1 MR. BINEK: Yes.

2 CROSS-EXAMINATION

3 BY MR. BINEK:

4 Q. Mr. Schiffman, on page nine of your
5 testimony you mentioned the peak wholesale power
6 price of \$1250 per megawatt-hour in July of 1998.
7 How long did that -- did that peak price exist?

8 A. Just for a few hours, and as I understand,
9 the liquidity or volumes that were traded at those
10 price levels were quite small.

11 Q. And the \$1426 per megawatt-hour in July
12 1999, how long did that peak wholesale power price
13 last?

14 A. Similarly. The prices were very spiky in
15 those periods and they weren't at sustained, high
16 levels.

17 Q. Do you have any average price for peak
18 power purchases for, say, the month of July 1998
19 and the month of July 1999?

20 A. I have that data. I don't know that I
21 have it immediately at my fingertips. I could get
22 that for you.

23 MR. BINEK: I think that would be helpful.

24 MR. HOBERG: Can you provide that as a
25 delayed exhibit, Mr. Pearce?

1 MR. PEARCE: Yes.

2 MR. HOBERG: Just mark it as perhaps what,
3 RJS number -- what would it be, 10?

4 MR. PEARCE: I think we're at 11.

5 MR. HOBERG: 11 for his?

6 MR. PEARCE: His last page on 15 I think
7 was 10.

8 MR. HOBERG: Okay.

9 THE WITNESS: I'm sorry. Just so I'm
10 clear, you want monthly prices for just that period
11 or for what period?

12 Q. (MR. BINEK CONTINUING) Well, those are
13 two that you referred to in your testimony, so I'd
14 like those. Also on page 12 of your testimony you
15 reference \$142 megawatt-hour during the on-peak
16 period of December 12, 2000. Probably that -- the
17 average for that month might be helpful, too.

18 MR. HOBERG: Okay. That would be -- it
19 would be RJS-12. You had 11 on your Exhibit 15.

20 MR. PEARCE: That's right.

21 THE WITNESS: All right. Thank you. Yes.
22 I can provide that.

23 Q. (MR. BINEK CONTINUING) Okay. Then also
24 on page 12 you talk about a \$47 per megawatt-hour
25 for -- that was reached the first time in recent

1 history for off-peak pricing in the winter of
2 2000-2001. When was that \$47 per megawatt-hour
3 reached? Was that an average you're talking about
4 or just a one peak-time period?

5 A. I believe that was a one time, but I don't
6 recall the frequency. Again, I could make that
7 data available.

8 Q. Okay. I'd appreciate that.

9 MR. HOBERG: Do you want to just make that
10 all part of the one exhibit?

11 THE WITNESS: Yes.

12 MR. HOBERG: Okay.

13 Q. (MR. BINEK CONTINUING) In your testimony
14 you had listed several factors that affect the
15 wholesale market environment. On page nine and
16 also on this recent discussion you talked about the
17 natural gas pricing, and on page nine, line eight,
18 you talked about this unprecedented increase in
19 natural gas pricing during the last quarter of
20 2000, the first quarter of 2001 as being a key
21 factor underlying electric market dynamics in 2001,
22 and you point out also on page nine that within the
23 MAPP region natural gas generators have been
24 playing an increasingly prominent role in
25 establishing spot market clearing prices.

1 That's correct, isn't it?

2 A. Yes.

3 Q. And just in your conversation -- or the
4 discussions you had after reading your surrebuttal
5 testimony, you've emphasized the fact of all of
6 this generation that's coming on-line in MAPP, and
7 that generation for the most part is all natural
8 gas, isn't it?

9 A. Yes, it is.

10 Q. That isn't -- isn't the fact that we're
11 going to be having this increased demand for
12 natural gas generation being created by all of this
13 new generation, not just in MAPP, but isn't that
14 also true throughout the country, that the new
15 generation coming on-line for the most part it's
16 gas fired?

17 A. Yes, most of the generation is gas-fired
18 that's coming on-line in the U.S.

19 Q. And isn't it also true that all of this
20 gas-fired generation is going to put an upward
21 pressure on natural gas prices and demand for
22 natural gas?

23 A. Well, relative -- I mean, all else fixed,
24 yes, that's true. I mean, the idea or the fact
25 that there's been a lot of electricity generation

1 coming in as gas-fired and likely to come in as
2 gas-fired has been well-known for several years,
3 though. So it's also reflected in the market
4 expectations, say, for natural gas and is reflected
5 in the fundamental price forecasts that people come
6 up with for predicting natural gas prices going
7 forward.

8 Q. And right now we're in a period of
9 relatively low prices of natural gas; isn't that
10 correct?

11 A. I would characterize it more as normal in
12 terms of long-term history.

13 Q. Okay. When prices are normal or at a
14 lower level, doesn't that also generally affect
15 drilling activity?

16 A. I think I would defer to Mr. Wilkinson on
17 that.

18 Q. Okay. And he talked about that yesterday.
19 On page 15 of your testimony you talked about the
20 2002 market outlook. Your 2002 market outlook is
21 based on projections, expectations and assumptions;
22 isn't that correct?

23 A. Well, yes. It's based on -- based on
24 looking at all of the market fundamentals that are
25 in play and based on those fundamentals making an

1 assessment of what would we expect to see in the
2 electricity markets during the coming months.

3 Q. And you've stated that the current outlook
4 is for natural gas price stability. That may or
5 may not happen; is that correct?

6 A. Yes, that's correct.

7 Q. You state -- and I'm not sure what page it
8 is. It's toward the end of your testimony -- that
9 price stability in the western U.S. market has been
10 bolstered by a return to normal or perhaps wet
11 hydro conditions in the western U.S. Isn't it true
12 that reservoir levels are very low due to the
13 drought that has persisted in the West for quite a
14 long period of time?

15 A. Well, last year was quite a dry year,
16 particularly in the Pacific Northwest. In the
17 current winter we don't have the full story yet,
18 but the first three months were actually 150
19 percent of normal in terms of -- in terms of
20 precipitation, and then it's been closer to normal
21 or perhaps a little dryer even in the recent
22 months, so that we don't have the full story, but I
23 think we'll be at least normal-type conditions, is
24 what's currently being projected for hydro in the
25 West.

1 Q. What -- what area of the West has this
2 excess precipitation?

3 A. Northern California has had quite high
4 snowpacks, and the Pacific Northwest as well, as I
5 understand, has had significant rainfall this year,
6 particularly in the early months.

7 Q. How about the Northern Rockies?

8 A. I don't know about the Northern Rockies.

9 Q. Are you aware of WAPA's projections about
10 cutbacks in the amount of hydroelectricity that
11 will be generated due to expected low -- or lower
12 flows out of the Rockies?

13 A. I'm not aware of that. What I'm referring
14 to here when I say western U.S. is primarily the
15 California and the Pacific Northwest prices. Those
16 are really not materially influenced by WAPA hydro
17 conditions. They're influenced by what we see in
18 northern California and what we see in Oregon and
19 Washington and then up into British Columbia.

20 Q. Do you know how much hydroelectric --
21 electricity capacity there is in the Missouri
22 system?

23 A. I haven't looked at that number. No.

24 Q. Are you aware of the fact, for instance,
25 the water levels in Lake Sakakawea, which is the

1 lake behind the Garrison Reservoir, in North
2 Dakota?

3 A. No. I have not reviewed hydro conditions
4 in the Missouri region or the Missouri River Basin.

5 Q. On page four of your testimony, beginning
6 at line four, you state that staff witness Diller
7 proposes that the level of off-system sales margins
8 experienced in 2001 basically were not normal or
9 average. Were you present in the hearing room when
10 Mr. Diller made his proposal to settle the resale
11 issue by using an average of sales margins during
12 the past three years for purposes of establishing
13 rates in this proceeding?

14 A. Yes, I was present.

15 Q. What is your -- your response or your
16 reaction to Mr. Diller's proposal?

17 A. Reaction in what sense?

18 Q. Well, I guess just that -- how do you feel
19 about his proposal?

20 A. Well, I believe that using the last three
21 years would likely still result in an overestimate
22 because of the price volatility seen, you know,
23 again in 2001 because of the increased gas prices
24 and the increased risk premiums as discussed in my
25 testimony and seen in the two previous years, or

1 particularly, I guess, you would pick up 1999
2 because of the volatility seen there that was left
3 over from the nuclear capacity outages.

4 So relative to what I would project going
5 forward in 2002, I would expect that it would still
6 result in an overestimate.

7 Q. Won't MAPP's increasing reliance on
8 natural gas cause electric energy prices to
9 increase compared to historical levels?

10 A. Not compared to what we've seen recently
11 in the historical prices because, again, the other
12 fundamental supply and demand conditions basically
13 are such that with the additional supply, with the
14 lower natural gas prices, my expectation is that
15 prices in 2002 will be lower than what we've seen
16 due to those other volatility characteristics in
17 recent years.

18 As indicated in Mr. Blinsky's testimony or
19 if you look at the two forward price series in
20 Exhibit 9, those are reflective of supply and
21 demand expectations in the market for 2002, which
22 includes the forecast of how much generation will
23 be gas-fired, how much of that will be marginal,
24 how much -- you know, what will the demand levels
25 be, what do people expect as -- does the market

1 expect as the natural gas prices. So this reflects
2 an expectation of those factors. The forward
3 prices already take into account the idea that
4 there's going to be more gas-fired generation.

5 Q. Your comparison, as I understood it, is to
6 reach recent historical prices, the very high
7 prices that have been talked about here.

8 A. Right.

9 Q. When you look at more average prices, then
10 isn't this reliance on natural gas going to cause
11 electric energy prices to increase?

12 A. All else fixed, an increased proportion of
13 gas capacity would be expected to cause an increase
14 in price. Now that'll depend on the mix of gas
15 capacity. You know, I would indicate still that
16 MAPP is primarily a coal-based market. It's not --
17 we haven't grown to the point in terms of gas
18 supply -- gas-fired generation supply, that MAPP is
19 dominated by gas. We expect it to be the marginal
20 resource maybe 50, 60, up to 70 percent of the time
21 on-peak and hardly of off-peak. So all else fixed,
22 the answer to your question is yes.

23 Q. Isn't gas a more expensive fuel than
24 lignite burned in mine-mouth plants?

25 A. Yes. Gas is more expensive, but the heat

1 rate -- you know, it depends on the gas technology
2 we're bringing in, as well. If it's a simple-cycle
3 unit, they've got a heat rate that's comparable to
4 the coal units, maybe slightly less, and so then
5 clearly there's a cost advantage. If you look at
6 combined cycle technologies, they see higher fuel
7 costs, but then they have improvements in thermal
8 efficiency, so the proportional increase in
9 production cost is smaller.

10 Q. I think you said you're from California?

11 A. Yes.

12 Q. How far ahead of time were you able to
13 predict the problems in California?

14 COMMISSIONER REINBOLD: The earthquake?

15 Q. (MR. BINEK CONTINUING) The energy
16 problem.

17 MR. HOBERG: Which problem, Mr. Binek?

18 COMMISSIONER REINBOLD: Not the
19 earthquake?

20 MR. BINEK: No.

21 COMMISSIONER REINBOLD: Excuse me.

22 THE WITNESS: When you say "the problems,"
23 could you be more specific.

24 Q. (MR. BINEK CONTINUING) Well, the whole
25 energy shortage that occurred in California the

1 last several months, all the brownouts, rolling
2 blackouts.

3 A. Right. We were -- say, in the summer of
4 2001 we were predicting prices that were spiking up
5 because the supply still was lagging in 2001-2002.
6 So we were predicting prices in the maybe \$200 per
7 megawatt-hour region at the spike in August in
8 California.

9 We weren't predicting anything near the
10 magnitude of what actually happened, and partly
11 what happened in California was just natural gas
12 prices. We're talking about average gas prices
13 here of five dollars and spiking at ten. Well,
14 they were at least twice that level in California
15 last year. We hit a spike of \$50 per MMBtu for
16 natural gas prices. You know, there were some
17 generators that saw, because of a shortage of nox
18 emissions credits, an additional \$100 per megawatt-
19 hour for nox credits.

20 So some of the impacts out there were
21 based on just pure fundamentals, the same as what's
22 been seen here in MAPP, and then some became, you
23 know, just a function of the breakdown of the
24 markets and of exercise of market power by
25 suppliers, and then near the end by the financial

1 distress faced by the IOU so that no one was
2 willing to sell into the market.

3 MR. BINEK: Looking at your final
4 statement in your testimony, I agree with the
5 portion of your statement that you make on page 17
6 where you say that forecasting energy market prices
7 is always a difficult exercise. No further
8 questions.

9 MR. HOBERG: Thank you, Mr. Binek. Mr.
10 Fahn, did you have any questions of Mr. Schiffman?

11 MR. FAHN: Yes.

12 EXAMINATION

13 BY MR. FAHN:

14 Q. Earlier I heard testimony about -- I mean,
15 a lot of the information that we have on the
16 effects of gas pricing and energy demand seem to be
17 a regional general view of things, and then I heard
18 a few questions about -- well, about snowpack and
19 snowpack in different areas of the country, and I'm
20 wondering if it would be -- if it would be
21 necessary -- if it is necessary or if it would be
22 important for the Commission to know more about the
23 demand for electricity or the areas where MDU is
24 selling this electricity. Rather than a regional
25 look, should we be getting into more detail so that

1 we can determine exactly spot -- like the spot
2 market type of look so we can determine for sure
3 what the impact would be in the future for MDU and
4 sales for resale?

5 A. I'm not sure I understand your question
6 completely. You mean in terms of focus on spot
7 markets closer to MDU like North Dakota?

8 Q. Focus on the markets -- maybe we should be
9 looking at the areas that purchased energy from MDU
10 in those sales for resale and looking at those
11 markets specifically to determine the future demand
12 for MDU's sales for resale.

13 A. Well, I believe that the -- you can't look
14 at those markets in isolation or at just the
15 entities that, per se, MDU is selling to. I mean,
16 Mr. Blinsky can probably describe in greater detail
17 and I can in terms of who are the actual parties on
18 the other sides of the transactions, but the
19 dynamics of the markets and -- I mean, the dynamics
20 of all of the power markets and all of the gas
21 markets is that they're connected, so that what
22 happens in -- you know, the reason we take regional
23 looks is because it's all of the regional supply
24 and demand conditions that result in what does the
25 price end up at in a given hour.

1 You know, the historical pattern in MAPP
2 markets has been -- they're lower cost because of
3 the lower cost of lignite coal and the closeness to
4 the Powder River Basin coal in Montana and Wyoming,
5 and they've had, you know, a greater amount of
6 particularly energy, sometimes capacity, but
7 particularly energy.

8 And Montana-Dakota sells into an energy
9 market. They're not long on capacity. As we've
10 talked about, they've been barely meeting the 15
11 percent requirement for MAPP, but they've got a lot
12 of coal-based generation so they're able to sell in
13 a lot of hours, and basically the trade patterns
14 have been that the energy that's available at lower
15 cost in particularly the northern and western MAPP
16 region basically ends up going towards some of the
17 higher demand or greater industrial production
18 regions, which are in northern Illinois and in the
19 St. Louis area and in Wisconsin.

20 It may be that Montana-Dakota is selling
21 to entities that are right next-door. I mean, I
22 would imagine a lot of their sales are to NSP, but
23 NSP's in a position where they're sitting kind of
24 right on the cost of one of the prime transmission
25 constraints that affects how much energy can flow

1 from the western MAPP region into these other
2 markets.

3 And so we could look at just what's going
4 in North Dakota, but the reality is that the price
5 is going to filter up from these other markets and
6 get brokered through somebody like NSP, and the
7 supply and demand fundamentals in those other
8 markets are what's going to ultimately determine,
9 you know, the greatest portion of the price, and
10 the only times that that won't be true is when the
11 transmission constraints are binding.

12 So, say, there's only -- say you can only
13 move 2,000 megawatts total of energy from MAPP
14 into, you know, either the Chicago or St. Louis
15 area and basically you hit a transmission limit.
16 Well, what will happen then is you'll see a
17 separation in the markets during that type of a
18 period so that you'll see higher prices in those
19 markets, in the Chicago markets and the St. Louis
20 markets and you'll see lower prices in MAPP because
21 they can't get the lower price generation out of
22 the region.

23 Q. I guess I was thinking that if there are
24 certain areas in the region that MDU sells to that
25 are controlling the price, that are affecting the

1 price to a greater degree, perhaps the Commission
2 should know the supply-and-demand situations in
3 those areas and maybe that would give them a better
4 picture of how, you know, the price for MDU's sales
5 for resale would be affected, and I guess the
6 question is -- what I've heard so far is that
7 you're thinking that it might not be beneficial for
8 the Commission to get into that much detail.

9 I guess I'll ask just one more time about
10 specific -- you did mention that specific areas
11 could control price, and so with that in mind, do
12 you think it would be beneficial for the Commission
13 to study specific areas?

14 A. I'm not sure the -- I mean, I'm not sure,
15 first of all, what areas you have in mind, but my
16 own view would be that if you want to look at, you
17 know, reasonable projection of a spot market-type
18 price, that it will take into account something
19 that's broader than, say, an individual utility
20 system or a small geographic area, because even if
21 somebody is long in supply and looks like they
22 don't need it, if somebody in an adjacent market
23 does, you know, they're able to basically broker
24 between the two.

25 So they'll take a spread on the

1 transaction and they'll move the power through
2 their system. You know, similarly if they're
3 short, you know, they'll buy from wherever.

4 But, I mean, the way the market works is
5 everybody that -- I mean, they try to use the most
6 efficient resources to meet demand, and there's
7 transactions back and forth to do that so you get
8 to the same point in terms of the clearing price,
9 and again, the only time that that doesn't happen
10 or wouldn't be expected to happen would be when
11 transmission constraints would preclude the
12 transactions.

13 MR. FAHN: Okay. Thank you.

14 MR. HOBERG: Thank you, Mr. Fahn.

15 Commissioner Wefald, did you have any questions?

16 COMMISSIONER WEFALD: I have a couple.

17 EXAMINATION

18 BY COMMISSIONER WEFALD:

19 Q. Would you explain this chart? That is --
20 this is -- I don't know the exhibit number because
21 it's not marked on mine.

22 MR. HOBERG: What's it say -- is it RJS-7?

23 COMMISSIONER WEFALD: It says Table 1.

24 THE WITNESS: It's Exhibit 9.

25 MR. HOBERG: 9.

1 Q. (COMMISSIONER WEFALD CONTINUING) Could
2 you explain Exhibit 9 to me? I know the NYMEX
3 futures strip. That's showing in March 2002 would
4 be -- 21.10 would be what the price would be for
5 the -- on the futures market for electricity on
6 that date.

7 A. Right.

8 Q. Is that the date that that price was
9 offered?

10 A. March 2002 would be the delivery period,
11 so that would be for electricity delivered -- you
12 know, in that example, for electricity delivered
13 under the terms of the future contract for the
14 month of March. So that's like an average on-peak
15 price for March. I think it's what, 730 megawatt-
16 hours during the month or something like that under
17 the terms of the futures contract.

18 Q. Okay. So when would -- that could have
19 been offered any time previous to March 2002; is
20 that correct? So, for example, if you were
21 purchasing electricity today from March 2002 and I
22 wanted to -- I would enter into a futures contract
23 for \$21.10 for March 2002?

24 A. Right. And then that's the price you
25 would pay for delivery of that energy in March.

1 Q. Okay. And then the Intercontinental
2 Exchange forward price is another market that I
3 could negotiate with for delivery at that time?

4 A. Right, exactly. And it's a similar
5 product in terms of its on-peak energy for delivery
6 in March.

7 Q. And these are all forward looking. Is
8 there any -- you know, Commissioner Clark asked
9 yesterday about what actual prices are for the
10 electricity in the past compared to what the
11 futures prices were. You haven't done any study
12 overnight to show that?

13 A. You mean in terms of --

14 Q. Historically, how accurate the futures
15 prices were to the actual price of electricity if
16 you needed to buy it on the open market on that
17 date?

18 A. No. I haven't completed a study to show
19 that. No.

20 Q. Okay. Thank you. All right. And you
21 mentioned about this projected demand, and in your
22 testimony you said something about Xcel. Can you
23 show me where it tells -- shows something about
24 Xcel in your chart? This is RJS-8.

25 MR. HOBERG: Exhibit 15.

1 Q. (COMMISSIONER WEFALD CONTINUING) Exhibit
2 15.

3 A. Yeah. In the MAPP report that I referred
4 to, which is Exhibit 13, they list -- or they
5 categorize the capacity that's under development
6 going to three different categories. One was the
7 capacity or was the project completed and is in the
8 market.

9 Q. And where is that? Where are you showing
10 finding that on here, in Exhibit 15? Is it in
11 Exhibit 15?

12 A. Yeah. In Exhibit 15 what I've done in,
13 say, the first page, which is RJS-8, is I've left
14 out the category -- I've left out one of the three
15 categories that they include. So what I put in
16 here is basically what would be viewed as the most
17 certain capacity, which is something that's either
18 already come into the market or something which is
19 currently being developed as a site identified and
20 they're actively in the permitting and financing
21 stages and in some cases have proceeded to
22 construction. In the report -- that's listed
23 either as completed or as sited in the MAPP report.
24 Then there's another category of capacity in the
25 MAPP report that's listed as unsited. So somebody

1 has identified that they're --

2 Q. So, wait. I need to have a little help
3 here. So up to 2001 that's the completed
4 megawatts. That's through Winterset, is that
5 right, Winterset, Iowa?

6 A. Yes. That's right.

7 Q. That's what's completed?

8 A. Right. And if you look over to the column
9 entitled cumulative and it says completed
10 megawatts --

11 Q. 1,774?

12 A. Right, exactly. And then after that is
13 the -- is the capacity that is identified and which
14 they list as having been sited but not completed.
15 So presumably the stuff that's identified in 2001
16 in that category, you know, it was under
17 construction but hadn't yet come on-line at the
18 time that they had gathered all the data for this
19 report.

20 Q. All right. And then you mentioned
21 something about Xcel?

22 A. Yes. Well, then there's a third category.
23 So if add up, say, at the bottom of what I've
24 listed as Exhibit RJS-8, by 2010, for example, the
25 very last number in the table is 7,614 megawatts.

1 So that's the amount of capacity if you add up all
2 of the projects that's either come into the market
3 or which has been listed and identified as under
4 development but hasn't actually come into the
5 market yet.

6 Then in addition to the capacity that's
7 identified there, so in addition to these specific
8 projects if you look at the next table, which is
9 entitled RJS-9, there's another category of
10 capacity that's identified in the report, which is
11 characterized in there as unsited. So this is
12 capacity that someone has said we're going to
13 procure, we're going to develop, but they haven't
14 said we're going to do it by building this
15 generating plant at this site.

16 Q. I was curious about your comments about
17 Xcel because at a meeting that the Commission held
18 about --

19 MR. HOBERG: Could somebody get the door
20 over there, please? Thank you.

21 Q. (COMMISSIONER WEFALD CONTINUING) A
22 meeting we had about two weeks ago, a periodic
23 information exchange meeting with Otter Tail, they
24 were giving us information about how there's a
25 proposed -- proposal to build a coal-fired -- coal

1 conversion to natural gas power plant in northern
2 Minnesota, and they're trying to convince the
3 legislature that they should mandate that all 3,000
4 megawatts would be purchased by Xcel.

5 So you said you thought that Xcel had
6 already made a determination of where they would be
7 getting their electricity. It doesn't sound like
8 they have from that because they're still --
9 they're still considering mandating that Xcel would
10 have to purchase 3,000 megawatts from this plant.

11 A. Right. The point I was trying to make is
12 I understand Xcel, or as I have known them, NSP's
13 supply procurement program, there's been a
14 competitive bidding proceeding that's been
15 partially mandated, partially approved by the
16 Minnesota Commission in conjunction also with an
17 integrated resource planning proceeding that
18 they're still subject to, and what they do in that
19 is they identify a schedule for we need this much
20 capacity, you know, in this time frame and we think
21 that it's going to be -- you know, say 500
22 megawatts of it is going to be intermediate-type
23 capacity and 200 megawatts is peaking-type
24 capacity, and then they go out regularly with RFPs
25 to try to procure that capacity under that

1 schedule.

2 That process was set up basically because
3 NSP at the time was trying to develop its own
4 projects, and a lot of independent power producers
5 were also interested in developing projects, and so
6 the process was put in place to try to create a
7 fair way for the utility portion of NSP to select
8 the right projects, the best projects for the
9 ratepayers.

10 Q. I understand the process.

11 A. Right. And as I understand it, they're
12 still -- the numbers that are listed in Exhibit
13 RJS-9, wherever it says in the categories entitled
14 "name," where it says "Various RFPs by Xcel," those
15 capacity requirements -- you know, NSP has
16 submitted to MAPP a schedule of we will be
17 responsible for this much capacity under this
18 schedule.

19 Q. But my understanding is that that's why
20 there's a lot of these power plant developments.
21 Even MDU, as you know, is considering building a
22 power plant.

23 A. Right.

24 Q. Why would they be building a power plant
25 if there's an excess of power shown right in these

1 numbers? If you're telling us that these numbers
2 show that there's -- not an excess of demand, but
3 an excess of capacity and there isn't any need for
4 additional power in the next few years, why would
5 Montana-Dakota Utilities be thinking about building
6 a power plant in North Dakota? Why would Otter
7 Tail be thinking of building a power plant in South
8 Dakota? Why would Great Plains be thinking of
9 building a power plant in several locations in the
10 Upper Midwest, and they're all hoping to sell to
11 Xcel or to someone else that power and they're
12 planning, and then this other project was being
13 considered up in northern Minnesota to add 3,000
14 megawatts because they want to share in this need
15 for additional demand that they see, and -- how do
16 you explain that if this -- these numbers show that
17 there isn't any needed demand in the MAPP region?

18 A. No. That's why I broke out separately
19 the -- say in the first part of this table the
20 cumulative and completed because, you're right,
21 they're likely -- if you add up all of this
22 capacity and say you get to the 10,000 megawatts by
23 2010, you know, there's going to be duplication
24 between this category unsited and sited because
25 some of the projects are being developed at least

1 in anticipation or hope that they'll sell power
2 supply contracts to existing LBCs in the MAPP
3 region.

4 I wouldn't characterize MAPP as a region
5 where I would expect large excess supply because
6 it's not the type of market that is that attractive
7 to merchant plant developers just to come in and
8 sell in the spot market. I mean, they're coming in
9 in this region primarily either to sell capacity to
10 hit the 15 percent reserve requirement that's
11 needed on peak, or they're developing capacity, you
12 know, largely with the hope of signing off-take
13 contracts with the LBCs.

14 Q. And in the meantime, though, as this NERC
15 study shows, that until those plants come on-line
16 with base-load power, there could be some
17 uncertainty in the market; would you agree with
18 that or not?

19 A. Some uncertainty in terms of the supply
20 demand balance?

21 Q. Yes.

22 A. In the next couple years I guess I don't
23 see that much uncertainty just because the -- you
24 know, the projects that are forecasted to come in
25 in that time frame have either come into the market

1 or they're under construction. Once they start
2 construction, they don't typically stop regardless
3 of market conditions.

4 Q. I understand that, but some of them are
5 going to take five to seven years to build.

6 A. If it's a coal plant.

7 Q. Yeah.

8 A. Yeah, sure. But I --

9 Q. That's what we're thinking of in the Upper
10 Midwest.

11 A. Yes. I think they'll make that decision
12 based on, you know, if -- I mean, I think that
13 people weren't considering too much coal until the
14 gas price spikes that we've seen in the last year,
15 year-and-a-half, and, you know, whether they
16 actually develop a coal plant or not will depend
17 upon how market conditions evolve over the next
18 couple of years.

19 I mean, there are always a lot of
20 uncertainties about what supply is going to come
21 in. What we've seen -- and MAPP is a region again
22 where I wouldn't expect a lot of excess. You know,
23 one of the -- one of the sort of oddities of
24 deregulation in some of the markets that have been
25 more developed, say in the Northeast, in

1 California, in -- even in the MAIN and ECAR region,
2 is that once they deregulate the markets, there's
3 actually been a glut of capacity under development,
4 or in Texas, for example.

5 Q. Well, they just went to deregulation in
6 January.

7 A. In Texas.

8 Q. Right.

9 A. Right. But the merchant plant development
10 started about three years ago. So they'll actually
11 be in -- it's like in the markets where
12 deregulation has been imminent --

13 Q. But we're not in that market, are we, here
14 in the Upper Midwest?

15 A. No. You're not in that market here, but
16 it does permeate, as I was indicating before.

17 Q. But they're not selling into Texas, MDU
18 isn't.

19 A. I'm not talking -- I understand that, but
20 they are selling into like Illinois, into the MAIN
21 markets.

22 Q. MAIN right now -- my understanding is that
23 there's a deficiency in the MAIN as far as
24 capacity?

25 A. A deficiency in MAIN?

1 Q. Capacity in MAIN.

2 A. That's not my understanding in terms of
3 2002 or 2003. There's been a lot of capacity
4 that's --

5 Q. Then how come it says --

6 A. -- come into the market.

7 MR. HOBERG: Commissioner Wefald, I think
8 you need to let him finish.

9 COMMISSIONER WEFALD: Okay.

10 MR. HOBERG: She's going to have trouble
11 taking the testimony if you don't let him finish.

12 Q. (COMMISSIONER WEFALD CONTINUING) All
13 right. Go ahead.

14 A. I mean, the larger point I'm trying to
15 make is that in a lot of the markets there's been a
16 lot of capacity that's come in when there's been,
17 you know, expected profit opportunities, and that
18 has -- in the 2002 through, say, 2005 time frame is
19 when most of that capacity is projected and will
20 come into the markets because it's under
21 construction currently. A lot of it hasn't come
22 in. It just started in MAIN, say, some of the
23 peaking units and some of the combined cycle units
24 came in in 2000-2001, and then there's an
25 acceleration that will be happening in, say, the

1 New England markets, in some of the ECAR markets
2 and some of the SERK markets in the next two to
3 three years, and then on the development side, you
4 know, you could forecast in a lot of regions where
5 there's been a lot of deregulation, you know, big
6 capacity surpluses in, say, the 2004 through 6, 7
7 time frame, and that's not a condition in MAPP that
8 you would forecast right now.

9 Q. If we were to be thinking only in terms of
10 the next, let's say, not 15 years but the next 3
11 years, is that a time of potential shortages or --
12 in MAIN and MAPP?

13 A. My own view is I think MAPP will be
14 primarily in balance over that time frame, and I
15 think in MAIN they'll see some of the -- they'll
16 see some of the influences of surpluses that are
17 coming into some of the New England markets, and
18 within MAIN itself, and so I would expect probably
19 some excesses or slight excesses in terms of the
20 price discovery, the influence of some slight
21 excesses in the MAIN region.

22 Q. Okay. I guess I'm curious about that
23 because in this NERC report on page 44, the one
24 that's labeled Exhibit 11, it says the ability to
25 import power may be severely limited in the near

1 term because of the lack of external resource
2 availability.

3 A. Yeah. Again, that NERC report -- I guess
4 I'm curious about it myself because it seems to
5 have taken a pessimistic view in terms of the
6 projects under development in a number of the
7 regions.

8 COMMISSIONER WEFALD: Thank you. That's
9 all I have. Thank you very much.

10 MR. HOBERG: Thank you, Commissioner
11 Wefald. Commissioner Reinbold, please.

12 COMMISSIONER REINBOLD: Couple questions,
13 Mr. Schiffman.

14 EXAMINATION

15 BY COMMISSIONER REINBOLD:

16 Q. First, let me compliment you and the other
17 witnesses' well-coordinated presentation here,
18 past, present and future, as I look at the array of
19 testimony givers here. Congratulations.

20 A. Thank you.

21 Q. When is the plant going to run on natural
22 gas?

23 A. I'm not an expert on that.

24 Q. Oh, okay. We don't -- is there anyone
25 else that you could ask?

1 A. Probably Mr. Fox.

2 Q. I worry a little bit at the rate natural
3 gas is being consumed, but nobody seems to have an
4 answer. When we talk about people in California
5 learning from their mistakes, do you talk about the
6 governor's office maybe, legislature?

7 A. Pretty much everybody in the whole market.

8 Q. Utility?

9 A. Yeah. It's pretty widespread.

10 Q. Regulators?

11 A. Yes.

12 Q. Everyone -- all of the above?

13 A. Yes.

14 Q. Okay. I've been accused of and
15 complimented for brevity in my questions in
16 proceedings, and I'm going to embark here upon the
17 mother of all brevities, and you're my subject.
18 Would you turn to page 16 of your testimony, your
19 direct testimony? There's a paragraph and a word
20 there that strikes me. It starts on line 7. Would
21 you read that question, the question given by
22 counsel?

23 A. I'm sorry. It was page 16?

24 Q. Page 16.

25 A. And line 7.

1 Q. Line 7, starting with "given."

2 A. It says, "Given your expectation of likely
3 2002 wholesale power market conditions in the
4 Midwest region, do you believe Montana-Dakota will
5 enjoy profit margins on off-system sales that are
6 comparable to the levels earned during 2001?"

7 Q. And your answer to that was no --

8 A. Right.

9 Q. -- and you elaborated further?

10 A. Right.

11 Q. But starting with the word "given" and
12 ending with a period after no, would you -- if that
13 paragraph and that answer was absorbed, believed
14 and adopted by this Commission, then we're pretty
15 near home, aren't we?

16 A. In terms of the rate case proceeding?

17 Q. Yes, yes, yes.

18 A. Yeah. I think it's one of the more
19 material issues or the most material issue.

20 COMMISSIONER REINBOLD: Okay. That's all
21 I have at this time. Thank you.

22 MR. HOBERG: Thank you, Commissioner
23 Reinbold. Commissioner Clark, please.

24 COMMISSIONER CLARK: Just one.

25

1 EXAMINATION

2 BY COMMISSIONER CLARK:

3 Q. We spent quite a bit of time this morning
4 talking about competitors to coal. Natural gas and
5 hydro are probably the two that we spent the most
6 time on, but I didn't hear much conversation about
7 nuclear, and although it's not a part of MDU's mix,
8 it is probably most notably with NSP in this region
9 here, and that, too, could be something that
10 impacts future markets for MDU coal. Is it safe to
11 characterize nuclear as kind of a wild card in
12 this, depending on what happens with the Yucca
13 Mountains and that whole situation?

14 A. In terms of the availability of nuclear?

15 Q. Well, in terms of the availability of
16 nuclear power, which would then impact export
17 markets for coal power if this nuclear being low-
18 cost form of power were to be jeopardized or kind
19 of threatened to go off-line.

20 A. Yeah. I mean, I think we saw that, you
21 know, again in 1998 and 1999, that if a large
22 portion of it came off-line, that you could have a
23 significant impact. That depends really on the
24 timing of when it came off-line. If it all came
25 off-line right away, it could have a huge impact if

1 because we weren't able to get through the Yucca
2 Mountains or weren't able to do relicensing or
3 didn't want to do steam generator replacement, and
4 we knew about that two or three years in advance,
5 it wouldn't have nearly as material of an impact
6 because people would have time to plan for it and
7 procure replacement supply.

8 COMMISSIONER CLARK: Okay. Thank you.
9 That's all I have.

10 MR. HOBERG: Thank you, Commissioner
11 Clark. Any further questions by commissioners?
12 Mr. Pearce, any further questions?

13 MR. PEARCE: Just one or two really.

14 REDIRECT EXAMINATION

15 BY MR. PEARCE:

16 Q. Commissioner Clark's question brings to
17 mind just a question that -- I think from what
18 you've testified to, the current future prices
19 basically are a result of every relevant factor
20 between nuclear generation and other kinds of
21 capacity, hydro, weather conditions, gas prices,
22 markets, everything; right?

23 A. Yeah. The futures prices and the forward
24 prices are, you know -- they're a culmination of
25 expectations of all the people in the market of

1 what conditions are going to occur, you know, in
2 the -- you know, as we indicated here in the
3 delivery period. So based on what do people think
4 the demand levels are going to be, the fuel price
5 levels, the amounts and types of capacity on-line
6 during that period, what do they think the supply
7 and demand conditions are going to be during that
8 period and based on that what will be the clearing
9 price.

10 Q. And then just one final question. You
11 agreed, I think, there would be some -- or
12 testified there would be some continuous upward
13 pressure on gas as more use is made of gas for
14 generation, but you wouldn't expect gas prices to
15 ever reach -- or in the near future anyway to reach
16 the 2001 levels, would you?

17 A. Well, not in the near future particularly
18 or in 2002. I mean, we're kind of through the
19 winter. So that's the period when you would
20 normally see a spike in natural gas prices. I
21 mean, I think gas prices typically are going to be
22 pretty stable in the spring through summer time
23 frame, and then, you know, there's some uncertainty
24 in terms of what could happen in the fall and
25 winter of next year.

1 MR. PEARCE: Thank you. That's all I
2 have.

3 MR. HOBERG: Thank you, Mr. Pearce. Mr.
4 Binek, anything further?

5 MR. BINEK: Yes, I do have a question.

6 REXCROSS-EXAMINATION

7 BY MR. BINEK:

8 Q. Looking at your Exhibit 15 and listening
9 to the discussion about the expectations and
10 projections concerning the -- the shortages of
11 capacity or the excess capacity of MAPP, and I'm
12 looking through this -- this list, and when you're
13 talking about the capacity that's needed, let's say
14 that the projections are that there will -- that
15 we'll need 10,000 megawatts of capacity by -- by
16 the year 2010. Is that actually 10,000 megawatts
17 of usable capacity that's needed? Is that what
18 they're talking about? And what I'm getting at, I
19 look at the list of projects here and I see at the
20 bottom of page one in Nebraska, GCW Wind Farm, 110
21 megawatts.

22 We all know that the capacity from a wind
23 farm -- if it's 110-megawatt wind farm, the
24 capacity is considerably less than that. That's
25 true of any kind of power plant. They don't -- you

1 know, the capacity is less than the total megawatt
2 capacity of the unit, you know, the efficiency is
3 less than that. So my question is, you know, when
4 I look at this, I'm assuming that the 110 megawatts
5 that's included for this wind farm is the stated
6 capacity of -- or, I mean, the nameplate capacity;
7 is that right?

8 A. I'm not sure exactly when they put this
9 together. They do list it in their report as
10 summer megawatts. So for wind whether they've done
11 some derating to reflect the fact that the wind
12 doesn't tend to blow on-peak, I don't know. For
13 the gas-type units I think that these would be
14 probably pretty accurate in terms of the actual
15 dependable capacity that would be available in the
16 on-peak period, you know, in the summer.

17 You know, they would be -- the gas plants,
18 for example, would be derated by outages and would
19 take a little hit for increased temperature
20 depending upon, you know, whether they used
21 chilling technology or something like that, but I
22 believe these numbers probably reflect that for the
23 gas units, at least that would be my expectation,
24 but I don't know that for certain.

25 Q. Would you agree that NSP's RFPs are a

1 demand, not a supply?

2 A. Yes. In terms of what they publish in the
3 RFPs, it's the need for power and then they go out
4 and contract for that power.

5 MR. BINEK: Okay. Thank you. No further
6 questions.

7 MR. HOBERG: Thank you, Mr. Binek. Mr.
8 Fahn, anything further?

9 MR. FAHN: No.

10 MR. HOBERG: Mr. Pearce?

11 MR. PEARCE: May I have one final?

12 REDIRECT EXAMINATION

13 BY MR. PEARCE:

14 Q. Mr. Schiffman, I've shown you Exhibit 3,
15 starting at the list of factors Mr. Diller
16 testified are relevant to the question of the
17 resale margin. You would agree, would you not,
18 that all those factors are wrapped up in and
19 relevant to the futures prices themselves? I mean,
20 they all form a part of how that futures price
21 would be determined?

22 A. Yes. There's some expectation of each of
23 those factors that would get rolled into the final
24 clearing price that's expected in the futures
25 price.

1 MR. PEARCE: Thank you. That's all I
2 have.

3 MR. HOBERG: Thank you, Mr. Pearce. Any
4 further questions then of Mr. Schiffman? Okay.
5 Thank you, Mr. Schiffman. Let's take a 10-, 12-
6 minute recess here, please.

7 (Recess taken.)

8 MR. HOBERG: Let's go back on the record.
9 Mr. Pearce, are you ready to call your next
10 witness?

11 MR. PEARCE: Yes, I am. I'll call Terry
12 L. Blinsky, please.

13 MR. HOBERG: Mr. Blinsky, I believe you
14 heard the admonition I gave earlier in regard to
15 perjury; is that correct?

16 THE WITNESS: Yes.

17 (Witness sworn.)

18 MR. HOBERG: Thank you. Mr. Pearce,
19 please.

20 TERRY L. BLINSKY,
21 having been first duly sworn, was examined and
22 testified as follows:

23 DIRECT EXAMINATION

24 BY MR. PEARCE:

25 Q. Would you please state your name, business

1 address and position?

2 A. Yes. My name is Terry L. Blinsky. My
3 business address is 400 North Fourth Street,
4 Bismarck, North Dakota, 58501. I am the electric
5 bulk power marketing coordinator for Montana-Dakota
6 Utilities Company, a division of MDU Resources
7 Group, Inc.

8 Q. And you also supplied some direct
9 testimony in this proceeding that's been filed,
10 didn't you?

11 A. Yes.

12 Q. What's the purpose of your surrebuttal
13 testimony today?

14 A. The purpose of my surrebuttal testimony is
15 to address concerns I have with the rebuttal
16 testimony of staff witness Mike Diller as it
17 relates to the area of wholesale sales.

18 Q. What concerns do you have with Mr.
19 Diller's testimony?

20 A. My concerns with his rebuttal testimony
21 relates to his comments on the correlation between
22 gas price and wholesale electric prices, his
23 characterization of off-peak sale margins and the
24 price and his reliance on actual historic levels in
25 light of the known changes and circumstances in the

1 current wholesale market.

2 Q. Would you please describe your concerns
3 regarding the correlation between gas prices and
4 sales for resale margins?

5 A. Yes. At page 9, lines 16 to 24, Mr.
6 Diller discusses this point and concludes that
7 natural gas prices declined throughout 2001 yet
8 sales for resale margins did not decline
9 correspondingly. We know that natural gas prices
10 declined during 2001, and we know that our actual
11 sales for resale margins in 2001 did not decline
12 with the gas price decline. However, Mr. Diller
13 has not recognized the cause for this lack of
14 correlation in 2001.

15 Very simply, the reason that sales for
16 resale margins remained up in 2001 was that
17 Montana-Dakota was successful in entering into a
18 contract with a buyer in March 2001 that covered
19 the summer season of 2001. At the time the
20 contract was executed, prices of gas and
21 electricity were still relatively high and the
22 buyer agreed to pay essentially the futures price
23 that existed at the time the contract was executed.

24 Thus, even though electric prices fell
25 during 2001, as did the gas price, the revenues

1 received by Montana-Dakota were dictated by the
2 contract and the buyer was obligated to pay the
3 contract price rather than the current price at the
4 time of delivery. Absent this contractual
5 arrangement, Montana-Dakota would not have been
6 able to retain the margins it did in 2001.

7 To illustrate this point I have prepared
8 Exhibit No. TLB-4. The exhibit shows the futures
9 prices that existed at the various times for
10 purchase in July and August of 2001. At the time
11 the contract was executed in March 2001, the
12 futures price for July and August was \$126 per
13 megawatt-hour. I'll make a correction in my
14 testimony. Instead of megawatt, it's megawatt-
15 hour.

16 These prices are representative of the
17 prices that the buyer agreed to when the contract
18 was executed. Had the contract not existed,
19 Montana-Dakota may not have been to see power --
20 would -- may have been able to sell power on a
21 month-to-month or day-to-day basis during the
22 summer but at prices current at the time of sale.

23 For example, Montana-Dakota could have
24 sold power in late June at about the July future
25 price that existed at that time, about \$46.75 per

1 megawatt-hour rather than the contract price at
2 142-and-a-half per megawatt-hour. Similarly, such
3 transactions could have occurred in August, as
4 well, but at prices substantially lower than the
5 contract price.

6 In summary, there is a direct correlation
7 between gas price and wholesale power prices, but
8 the correlation was not evident because of the
9 contract provisions that Montana-Dakota had in
10 place in 2001.

11 Q. Does Montana-Dakota have any contracts for
12 the sale of power in place currently or for the
13 upcoming summer season?

14 A. No.

15 Q. What are your concerns with Mr. Diller's
16 characterization of off-peak margins and prices?

17 A. At page 10, lines 20 through 25 of his
18 rebuttal testimony, Mr. Diller states that
19 Montana-Dakota estimates that off-peak sales
20 comprise about 47 percent of the total sales and
21 are priced below the cost of fuel. This statement
22 is not correct.

23 First, the peak and off-peak sale
24 megawatts are not estimates. They represent the
25 actual levels of peak and off-peak sale levels that

1 occurred.

2 Second, the off-peak sales are not priced
3 below fuel cost. Montana-Dakota keeps specific
4 records of peak and off-peak sales for megawatts by
5 time period. However, the fuel costs shown on the
6 exhibit are actual fuel costs on an average basis
7 for the month as Montana-Dakota does not keep a
8 specific record of the actual fuel costs by peak
9 and off-peak periods.

10 When energy is sold in the off-peak
11 periods, it is typically sold from a specific unit
12 and Montana-Dakota knows what the incremental fuel
13 cost of that particular unit is at the time of the
14 sale. It is not our common practice to sell below
15 the incremental fuel cost of the unit.

16 The resulting total margin shown on my
17 Exhibit No. TLB-3 is correct. If specific records
18 had been kept for peak and off-peak fuel costs, we
19 would find that the peak fuel costs would be above
20 the average and the off-peak fuel costs would be
21 below the average. As this information was not
22 available, the actual fuel costs on an average
23 basis were used.

24 Q. Would you please describe your concern
25 with the reliance on historical information in

1 light of the known changes and circumstances in the
2 wholesale market?

3 A. Yes. As I explained in my direct
4 testimony, the wholesale market environment has
5 drastically changed and our opportunities to make
6 higher wholesale sales margins no longer exist.
7 Reliance on the historical actual results in this
8 case will significantly overstate the margins that
9 Montana-Dakota can expect to make in the future.

10 For example, actual January 2002 wholesale
11 sales were 92,964 megawatt-hours and brought a
12 total margin of 622,000. Actual January 2001
13 wholesale sales were 83,940 megawatt-hours with an
14 actual margin of 1,316,000. Even though we sold
15 more megawatt-hours in January 2002, the margin was
16 lower by over 50 percent. This is reflective of
17 the drop in price. Similar results can be seen for
18 February 2002 as compared to February 2001.

19 Q. Have you updated your Exhibit TLB-3 that
20 was part of your direct testimony to reflect
21 changes since the time you've prepared it?

22 A. Yes, I have. The updated information is
23 shown on Exhibit No. TLB-5.

24 Q. Would you please explain that exhibit?

25 A. Yes. The megawatt-hours of sales are the

1 actual volumes sold for the 11-month period ending
2 January 2002 plus an estimate for February 2002
3 based on the actual volumes for the first 14 days
4 doubled to reflect the full month of 28 days.

5 The projected margins shown in the last
6 column represent the actual for January 2002 and
7 the actual level for the first 14 days of February
8 2002 doubled for the full month.

9 The margin for the remaining months was
10 calculated using the Cinergy futures prices for
11 on-peak energy as of February 16, 2002, and
12 off-peak prices which reflect prices currently
13 being obtained for off-peak energy.

14 The resulting total margin that can be
15 expected is 6,429,778. This is about 818,000 less
16 than the expected margin shown on Exhibit No. TLB-3
17 submitted with my direct testimony.

18 The megawatt hours of sales are similar
19 but the prices have fallen since preparation of the
20 initial exhibit. This further demonstrates the
21 fact that prices are not rebounding to the levels
22 seen in the last year. I have shown the February
23 16th, 2002, NYMEX Cinergy energy prices on Exhibit
24 No. TLB-6.

25 Q. Why is it appropriate, in your opinion, to

1 rely on the NYMEX futures prices?

2 A. First, the NYMEX futures price represents
3 the price of actual transactions between willing
4 sellers and willing buyers. Second, the Cinergy
5 hub is a hub nearest Montana-Dakota's service area,
6 MAPP region, and is available to all market
7 participants we typically deal with.

8 These prices are used as a guide by market
9 participants when buying or selling energy. In
10 fact, the current prices that Montana-Dakota has
11 been able to sell on-peak power at very closely
12 align with the March 2002 futures prices.

13 I would also know that a recent offer was
14 made to purchase electricity from Montana-Dakota at
15 \$35 per megawatt hour for July and August 2002,
16 somewhat below the posted future price of 38-and-a-
17 quarter for July and August 2002.

18 Finally, as I described earlier in this
19 testimony, Montana-Dakota was able to obtain a
20 contract for the summer season of 2001 last March
21 that was based on the futures prices in existence
22 at that time.

23 Q. Would you please summarize your position
24 on wholesale sales levels?

25 A. Yes. Montana-Dakota's ability to make

1 wholesale sales at higher prices peaked in 2001 and
2 will not reoccur in the foreseeable future. It was
3 a market anomaly that allowed us to achieve the
4 higher prices. Currently, there is more supply
5 available than in the past and gas prices are down
6 and expected to stay there, which has the effect of
7 lowering prices for electricity as there are a
8 number of gas-fired generators on line and the
9 price differential between coal-fired and gas-fired
10 generation is now much narrower.

11 These factors are also supported by other
12 witnesses in this proceeding. This means we will
13 not be able to achieve prices we saw in the last
14 few years. Based on the latest information
15 available, Montana-Dakota can only expect to
16 achieve wholesale sale margins of 6,429,778 as
17 shown on my Exhibit No. TLB-5.

18 Q. Mr. Blinsky, did you hear Mr. Schiffman's
19 testimony this morning with respect to his Exhibit
20 9 of which I've handed you a copy?

21 A. Yes, I did.

22 Q. And you understand what that exhibit
23 shows?

24 A. Yes, I do.

25 Q. And I've also handed you Exhibit 10. Is

1 that an exhibit prepared by you and under your
2 direction and control?

3 A. Yes.

4 Q. Would you explain what Exhibit 10 shows?

5 A. What Exhibit 10 shows is in my earlier
6 exhibits, No. 5, I based the futures margins for
7 2002 based on the NYMEX future prices, then took a
8 look at the exhibit that Mr. Schiffman had showing
9 the forward prices from the Intercontinental
10 Exchange, and what I did then was to stick those
11 forward prices into the exhibit where I had the
12 futures, and that brought a new estimated margin
13 for 2002 to 6,080,199.

14 Q. In other words, what your -- what exhibit
15 10 shows is a calculation parallel to what your
16 TLB-5 shows but using the figures that Mr.
17 Schiffman testified to with his Exhibit 9?

18 A. That is correct.

19 Q. And the conclusion is within about
20 \$400,000 of the same conclusion that you reached
21 using the NYMEX futures?

22 A. That is correct.

23 Q. And those NYMEX futures you used were as
24 of February 16th. I think you testified that
25 appears to be the same date that appears on Exhibit

1 9 for Mr. Schiffman's figures, is it not?

2 A. That is correct.

3 Q. Those prices correspond with the same
4 date?

5 A. Yes.

6 Q. Does it surprise you that the two methods
7 would reach very nearly the same result?

8 A. No.

9 Q. Is Exhibit 10, to the best of your
10 information and belief that you said you prepared,
11 true and correct?

12 A. Would you restate that?

13 Q. I'm sorry. I didn't state that very well.
14 Are the data contained in Exhibit 10 which you
15 prepared true to the best of your information and
16 belief?

17 A. Yes.

18 MR. PEARCE: I'll offer Exhibit 10.

19 MR. HOBERG: Any objection?

20 MR. BINEK: No.

21 MR. HOBERG: Exhibit 10 is admitted.

22 MR. PEARCE: And I have nothing further.

23 MR. HOBERG: Nothing further, did you say,
24 Mr. Pearce?

25 MR. PEARCE: Right.

1 time?

2 A. Could you restate that, please?

3 Q. Was MDU deficient in MAPP reserves at that
4 time?

5 A. No. Not at the time I made that contract.

6 Q. But during the time of the contract did
7 MDU fall into a deficit position in their -- with
8 their MAPP reserves?

9 A. On capacity, yes.

10 Q. I think you briefly touched on this, but
11 did -- did MDU enter into any futures contracts to
12 sell power in the wholesale market this month?

13 A. No.

14 Q. How about last month?

15 A. When you talk about entering into
16 contracts into the futures, we do not trade
17 futures.

18 Q. Okay. So you haven't done any -- you
19 don't have any outstanding now. You haven't sold
20 any through the futures market?

21 A. No.

22 Q. If MDU believed the wholesale electric
23 market would improve in the next year or two, it
24 would be foolish for MDU to enter into any futures
25 contracts; isn't that true?

1 A. Could you restate that, please?

2 Q. If MDU believed the wholesale electric
3 market would improve, in other words, there would
4 be more margin in the next year or two, it would be
5 foolish for MDU to enter into any futures contracts
6 today; isn't that correct?

7 A. That is correct. At the levels I'm seeing
8 in 2002 looking at the gas price, we have two
9 turbines out there that the cost would be greater
10 than the price that we were quoted. So, therefore,
11 we would not sell it at that point.

12 Q. Were you --

13 MR. HOBERG: Mr. Lein, could you get the
14 door over there, please, shut it?

15 Q. (MR. BINEK CONTINUING) Were you present
16 in the hearing room yesterday when Mr. Diller made
17 his proposal to settle the resale issue by using an
18 average of resale margins during the past three
19 years for the purposes of establishing rates in
20 this proceeding?

21 A. Yes, I was.

22 Q. What is your response to Mr. Diller's
23 proposal?

24 A. I believe if we were to use the three-year
25 average as Mr. Diller has suggested, taking into

1 consideration what happened for those three years
2 would overemphasize what we could mark in the year
3 2000 and forward. In other words, his average is
4 way too high than what we believe looking out into
5 2002 and the future we can make marginwise.

6 Q. You talked about the statement that Mr.
7 Diller made on page ten of his rebuttal testimony.
8 Do you think Mr. Diller is unaware that your
9 schedule was -- uses actual sales levels for 2001?

10 A. I don't have a copy of Mr. Diller's
11 report, if I could look at what you're referring
12 to, please.

13 MR. DILLER: Well, it's the thing that you
14 said I was incorrect on.

15 THE WITNESS: Okay. Which line.

16 MR. DILLER: Line 20.

17 THE WITNESS: Excuse me?

18 MR. DILLER: Line 20 and 21.

19 Q. (MR. BINEK CONTINUING) Would you just
20 read that?

21 A. We're on page 10, line 20.

22 Q. (MR. BINEK CONTINUING) 20 to 25 are the
23 lines that you reference in your testimony as
24 being --

25 A. Okay. You want me to read his starting

1 with "MDU's"?

2 Q. Right.

3 A. "MDU's estimate of 2002 off-system sale
4 margins begins by dividing the total sales into
5 on-peak and off-peak units. MDU estimates that the
6 off-peak sales, sales from 10 until 6 a.m. and all
7 day Sunday, comprise about 47 percent of the total
8 sales and the price below the cost of fuel. Such
9 an assumption results in the net loss contribution
10 of 144,319 for 2002. Staff can understand why on
11 occasion the company might" -- that's it?

12 Q. And my question is: Do you think Mr.
13 Diller is unaware that your schedule uses actual
14 sales levels for 2001?

15 A. I'm still not sure what you're referring
16 to on this on and off peak. What he's referring to
17 is he was looking at the fuel cost to project 2002
18 minus the off-peak price and looking like it was a
19 negative, is what I'm reading. Is that your
20 question?

21 Q. Okay. Is it possible that Mr. Diller uses
22 the word "estimate" to relay the fact that even
23 though MDU's projection is based on actual sales
24 volumes, it is still an estimate for 2002?

25 A. We're just trying to point out that the

1 margins for 2002 is based on our best possible
2 scenario using the information we had, and I did
3 not think he understood that we're not actually
4 selling off peak at a loss. So I think he was
5 using the estimate in that term of on and off peak.

6 Q. Isn't the 47 percent an estimate for 2002?

7 A. Yes, based on 2001.

8 Q. And the actual sales volumes for 2001 are
9 in fact estimates for 2002?

10 A. That is correct, except for January and
11 February that we used on the new exhibit for TLB-5.

12 Q. This 50 megawatts that was sold that you
13 referred to on page two of your surrebuttal
14 testimony, who bought that 50-megawatt block?

15 A. That was a confidentiality agreement. I
16 cannot disclose the buyer.

17 MR. PEARCE: Just for the record, I would
18 object, as well. It's not that we're trying to
19 obfuscate, but the contract itself does contain a
20 confidentiality provision that we could not reveal
21 without the consent of the other contracting party.

22 MR. HOBERG: Thank you, Mr. Pearce. Mr.
23 Binek.

24 Q. (MR. BINEK CONTINUING) Just a curiosity
25 question, this 47 percent of off-peak capacity,

1 who's purchasing that electricity? Can you tell us
2 that?

3 A. The off peak?

4 Q. Yeah.

5 A. Various companies throughout MAPP. It can
6 either be sold on a daily basis, hourly basis,
7 monthly basis, the party that was sold under this
8 six-month contract. So there's a lot of parties
9 involved in that off-peak price -- or off-peak
10 megawatt hours, I should say.

11 MR. BINEK: No further questions.

12 MR. HOBERG: Thank you, Mr. Binek. Mr.
13 Fahn, did you have any questions of Mr. Blinsky?

14 MR. FAHN: No, thank you.

15 MR. HOBERG: Thank you. Commissioner
16 Wefald, please, do you have any questions of Mr.
17 Blinsky?

18 EXAMINATION

19 BY COMMISSIONER WEFALD:

20 Q. Exhibit 10 is basically a projection, is
21 that correct, based on the data that you have
22 available about the futures prices at this time?

23 A. That would be correct.

24 Q. And that projection could change next week
25 if the futures prices changed. It could go upward

1 or it could go downward?

2 A. That would be correct.

3 COMMISSIONER WEFALD: Thank you. That's
4 all I have.

5 MR. HOBERG: Thank you, Commissioner
6 Wefald. Commissioner Reinbold, please.

7 COMMISSIONER REINBOLD: I have no
8 questions of this witness at this time.

9 MR. HOBERG: Thank you. Commissioner
10 Clark, please.

11 COMMISSIONER CLARK: I have none. Thank
12 you.

13 MR. HOBERG: No questions. Okay. Thank
14 you. Mr. Pearce, any further questions?

15 MR. PEARCE: Just one, I think, or perhaps
16 two.

17 REDIRECT EXAMINATION

18 BY MR. PEARCE:

19 Q. Mr. Blinsky, the contract you've testified
20 to entered into in 2001, it wouldn't be the case
21 that that -- the existence of that contract caused
22 a capacity deficit for MDU under its MAPP reserve
23 obligations later in the year, was it?

24 A. No.

25 Q. You were selling energy in that contract;

1 is that right?

2 A. That is correct.

3 Q. As opposed to capacity?

4 A. That's correct.

5 Q. I see you said you had no contracts in
6 place today. Would it be fair to say that if you
7 got an offer from someone wishing a contract at a
8 good price, you'd be happy to enter into a
9 contract?

10 A. Looking at the futures and what the market
11 is talking about -- every day you talk to marketers
12 as parts of your business and we all discuss what's
13 going to happen in the future, and it seems gloom.
14 If I had somebody approach me and even wanted to
15 negotiate, I would sure listen.

16 MR. PEARCE: Thank you. That's all I
17 have.

18 MR. HOBERG: Any further questions then of
19 Mr. Blinsky? Thank you, Mr. Blinsky.

20 THE WITNESS: Thank you.

21 MR. HOBERG: Do you want to deal with that
22 Exhibit 8, Mr. Pearce?

23 MR. PEARCE: Oh, yes.

24 MR. HOBERG: As I recall Exhibit 8 -- I
25 don't know if we have copies of it. We had marked

1 Exhibit 8, and it was part of the surrebuttal
2 testimony of Dr. Gaske, but it didn't actually get
3 offered yesterday, and I'm wondering, Mr. Binek, if
4 you'd be willing to stipulate to its admission.

5 MR. BINEK: Sure.

6 MR. HOBERG: Do you have copies for the
7 Commission?

8 MR. PEARCE: We must. Do we have some
9 copies somewhere? It's about a four-page or
10 three-page -- JSG-4 schedule. I'm sure we have
11 some copies here. Perhaps we'd like to -- Dr.
12 Gaske testified about it. As I recall, it's the
13 mathematical calculation of the relation to the --

14 MR. HOBERG: That's Exhibit 8.

15 COMMISSIONER REINBOLD: 8?

16 MR. HOBERG: 8.

17 MR. PEARCE: This was -- Dr. Gaske talked
18 about this yesterday. He just identified what it
19 is. It's mostly algebraic computations.

20 MR. HOBERG: Okay. Thank you, Mr. Pearce.
21 All right. Your next witness, please.

22 MR. PEARCE: I will call Douglass
23 Mahowald.

24 MR. HOBERG: I should note while he's
25 coming up that Mr. Blinsky's testimony was -- his

1 direct was Docket No. 48 and his surrebuttal was
2 Docket No. 59, and those are -- again, the direct
3 is found in Exhibit 6 and Exhibit 7 is the
4 surrebuttal. Okay. Mr. -- how do you pronounce
5 that again?

6 MR. PEARCE: Mahowald.

7 MR. HOBERG: All right.

8 COMMISSIONER REINBOLD: Is that
9 Scandinavian?

10 THE WITNESS: No. It's Luxembourg.
11 Luxembourg in Germany.

12 COMMISSIONER REINBOLD: Oh, I've been
13 there.

14 THE WITNESS: Have you?

15 COMMISSIONER REINBOLD: I didn't see you.
16 Must have been a different time.

17 MR. HOBERG: Mr. Mahowald, I think you
18 heard the admonition I gave in regard to perjury
19 earlier?

20 THE WITNESS: Yes.

21 (Witness sworn.)

22 MR. HOBERG: Thank you. Mr. Pearce,
23 please.

24

25

1 DOUGLASS A. MAHOWALD,
2 having been first duly sworn, was examined and
3 testified as follows:

4 DIRECT EXAMINATION

5 BY MR. PEARCE:

6 Q. Would you state your name and address,
7 please, and your place of business?

8 A. My name is Douglass A. Mahowald. My
9 business address is 918 East Divide Avenue,
10 Bismarck, North Dakota, 58506.

11 Q. And in what capacity are you employed by
12 MDU Resources Group, Inc.?

13 A. I'm assistant treasurer and assistant
14 secretary.

15 Q. And would you please describe your duties
16 in that capacity?

17 A. I'm responsible for the treasury services
18 functions of the company, which includes the
19 company's cash management program, maintaining bank
20 and financial relationships, administration of the
21 company's short- and long-term debt financing
22 program, financial analysis, debt compliance. I
23 also assist in the administration of various
24 benefit plans and the company's risk management
25 hedging program.

1 Q. Would you please outline briefly your
2 educational and professional background?

3 A. In 1972 I received a Bachelor of Arts
4 degree in business administration with a
5 concentration in finance from the University of St.
6 Thomas, St. Paul, Minnesota. Upon graduating from
7 the University of St. Thomas I held various
8 accounting and financial positions with several
9 firms in Minot, North Dakota, and Minneapolis,
10 Minnesota.

11 In February 1982 I joined Montana-Dakota
12 as a budget statistician. I was promoted to
13 treasury services manager in November 1982. In
14 that capacity I was responsible for treasury
15 service functions, including the company's cash
16 management program. In August 1992 I was promoted
17 to assistant treasurer and assistant secretary of
18 MDU Resources Group, Inc.

19 Q. Have you previously testified in
20 proceedings before regulatory commissions?

21 A. Yes. I have testified before the Montana
22 Public Service Commission and the Wyoming Public
23 Service Commission.

24 Q. What is the purpose of your testimony here
25 today?

1 A. The purpose of my surrebuttal testimony is
2 to describe the debt refinancing that incurred in
3 April of 1992, which is referenced in the
4 surrebuttal testimony of Dr. Gaske.

5 Q. What did the company refinance in 1992?

6 A. The company refinanced 100 million dollars
7 of first mortgage bonds represented by the five
8 series of bond issues shown under the pre-
9 refinancing heading on page one of my Exhibit
10 DAM-1. That long-term debt was replaced with the
11 issues shown under the post-refinancing heading
12 shown on page one of the exhibit.

13 Q. One point of clarification. When we're
14 using the term "company" here, we're talking about
15 MDU Resources Group, Inc., aren't we?

16 A. Yes.

17 Q. Why did the company refinance the first
18 mortgage bonds in 1992?

19 A. The company's primary objective in
20 refinancing its long-term debt in 1992 was to lower
21 the overall cost of its long-term debt. The
22 company achieved this objective through the
23 refinancing that was completed at that time. This
24 is shown in Exhibit No. DAM-1.

25 Page one of the exhibit is a comparison of

1 the cost of the issues redeemed and the cost of the
2 new issues, which replace the redeemed issues. As
3 shown, the pre-refinancing coupon interest rate for
4 this group was 9.258 percent, and the post-
5 refinancing coupon interest rate for the group
6 was 7.657 percent.

7 Also as shown on page one, the pre-
8 refinancing costs for the group was 10.215 percent,
9 and the post-refinancing costs for the group was
10 9.508 percent. This resulted in an annual savings
11 of \$231,500. Page two of the exhibit shows
12 Montana-Dakota's total embedded cost of long-term
13 debt at 9.965 percent for the 12 months ending
14 December 31st, 1991, immediately before the
15 refinancing.

16 Page three of the exhibit shows a total
17 embedded cost of long-term debt at 9.69 percent for
18 the 12 months ending December 31st, 1992, or
19 immediately after the refinancing.

20 This exhibit clearly shows the company was
21 able to lower its cost of the issues redeemed as
22 well as lower its total cost of long-term debt by
23 2.75 percent through this refinancing in 1992.
24 This lower cost of long-term debt has been a direct
25 benefit to the company's customers.

1 Q. Has the company considered refinancing
2 this debt that was refinanced in 1992?

3 A. Yes. The company has considered
4 refinancing this group of long-term debt issues.
5 However, the company has not taken any formal
6 action to refinance this debt because this action
7 would cause an increase in the total cost.

8 Q. Why would refinancing now what appears to
9 be a lower coupon rate increase the total costs?

10 A. In order to lower the overall cost of its
11 long-term debt in 1992 and provide a direct benefit
12 to its customers, the company issued debt at then
13 prevailing interest rates and market conditions.
14 Based on the current prevailing interest rates, the
15 company anticipates that refinancing this group of
16 existing long-term debt issues may lower the
17 overall interest coupon rate for the group.

18 However, the company would incur
19 significant costs to reacquire this debt from
20 existing holders in order to refinance. After
21 accounting for the reacquisition costs for this
22 group of existing long-term-debt issues, most
23 notably the loss on reacquired debt, any
24 refinancing action would increase the overall
25 embedded cost of the company's existing long-term

1 debt and penalize its customers.

2 Q. Mr. Mahowald, you stated a moment ago --
3 and this goes back to line 15 on page 3 of your
4 written testimony. I believe, unless I misheard,
5 you said 2.75. Did you mean 0.275?

6 A. Yes. .275.

7 Q. In the course of your duties with the
8 current corporation, Mr. Mahowald, do you as a
9 regular matter monitor and continually keep in mind
10 the possibility of refinancing if it would be
11 economic and feasible?

12 A. We look at that on an ongoing basis,
13 almost on a daily basis.

14 Q. And would you -- you wouldn't anticipate,
15 would you, that the debt costs would necessarily be
16 the same for other utilities, even other utilities
17 in this area because it depends on various factors,
18 does it not?

19 A. Right.

20 Q. And what are some of those factors -- I
21 imagine it involves the question of timing,
22 questions of that kind?

23 A. Well, the cost of debt and the capital
24 market fluctuates over time. As companies issue
25 new debt to finance new plant or repay existing

1 questioning Dr. Gaske, the discussion about this
2 cost of debt he was raising -- or talking about
3 several factors, and one of the major ones was that
4 during this time period MDU was in the process of
5 constructing a power plant, and he referred
6 specifically to the Coyote power plant. There had
7 been -- Mr. Diller's testimony compared your cost
8 of debt to that of NSP and Otter Tail Power
9 Company, and your debt was considerably higher.
10 I'm referring specifically to Otter Tail Power
11 plant. Wasn't Otter Tail Power Company a partner
12 in the construction of the Coyote plant?

13 A. Yes.

14 Q. In fact, Otter Tail Power Company had a
15 larger share of the construction of that power
16 plant than MDU did; isn't that also correct?

17 A. Yes, I believe so.

18 Q. Were you present in the hearing room when
19 I asked Mr. King about this 40-million-dollar term
20 loan from the Bank of America?

21 A. Yes.

22 Q. Is it true that the 40 million dollars was
23 borrowed on December 29th, 2000, and that it
24 matured on January 2, 2001?

25 A. That -- that sounds familiar. I'd have to

1 go back and look. I don't know the exact dates,
2 but that sounds appropriate.

3 Q. Okay. This was basically a four-day loan;
4 is that correct?

5 A. That would be four days.

6 Q. Okay. Now, am I also correct that MDU was
7 carrying it on its books as part of its overall
8 debt, the full 40 million dollars?

9 A. I believe so.

10 Q. What was the purpose of that loan?

11 A. For regulatory reasons we borrow
12 short-term commercial paper throughout the year.
13 For regulatory purposes -- not regulatory -- well,
14 for rating agency purposes -- not regulatory
15 purposes -- rating agency purposes we need to be
16 able to demonstrate to the rating agencies that we
17 have capacity to clear our short-term lines. So we
18 basically put that money into clear that -- into
19 the term loan and then --

20 Q. Okay. You have the capacity to clear
21 what?

22 A. Well, for rating agency purposes we have
23 the commercial paper program, and they like to see
24 our quarter ratios, year-end ratios within certain
25 lines so we don't have so much classified as short-

1 term debt. So we move that short-term debt into
2 the term loan so we can evidence financial
3 strength.

4 Q. Well, doesn't that -- isn't that a
5 distortion of what is actually occurring within the
6 company?

7 A. I wouldn't call it a distortion. I think
8 it's another viable option to finance at that time.
9 I think the prime rate at that time was nine-and-a-
10 half percent, so it was a competitive -- or nine-
11 and-a-quarter percent, so it was a competitive
12 interest rate we received on that money.

13 Q. Now you said -- I believe you said that
14 the full 40 million dollars was included in the --
15 in the overall debt of the company at that time; is
16 that right?

17 A. I believe so. I'd have to check the
18 records.

19 Q. Well, if that is in fact the case, wasn't
20 that a distortion of the capital structure of the
21 company?

22 A. I wouldn't think so because at that time
23 prevailing interest rates were very competitive,
24 that 9.75 draw.

25 Q. Well, when Mr. King reviewed this, he

1 reduced your debt by almost all but 1.3 million of
2 that 40 million; isn't that correct?

3 A. That I don't know. I haven't looked at
4 that part of the testimony.

5 Q. Assuming that -- assuming that that is
6 correct, that would have reduced your overall debt
7 by 38-and-a-half-million dollars in your capital
8 structure; isn't that correct?

9 A. If that was done, that would be correct.
10 Yes.

11 Q. So when you showed a capital structure
12 with debt at 38-and-a-half-million dollars higher
13 than what it actually was, wasn't that a distortion
14 of the capital structure?

15 A. Repeat that question.

16 Q. Well, when your debt -- when you file a
17 report, annual report or whatever -- and I don't
18 know what was provided to Mr. Gaske, but when that
19 shows a debt -- the company's debt at 38-and-a-
20 half-million dollars higher than it should be,
21 isn't that a distortion of the capital structure?

22 A. Why would that be higher, because it was
23 debt we had on our books?

24 Q. Well, if -- if you agree that in his
25 report that's been reduced by 38-and-a-half-million

1 dollars, wasn't it 38-and-a-half-million dollars
2 too high?

3 A. Well, I haven't read his direct testimony,
4 so I --

5 Q. Well, assuming that was done and assuming
6 that MDU has not objected to it, wouldn't you agree
7 that the debt was overstated by 38-and-a-half-
8 million dollars?

9 A. Well, if MDU agrees to that, I guess yes.

10 Q. What's the difference between the coupon
11 cost and the cost-of-money basis?

12 A. Well, the coupon rate would be the actual
13 interest coupon rate on the debt, where the cost of
14 money would include the reacquired costs, the
15 issuance costs and those various things.

16 Q. The prefinancing annual cost was 10.2
17 million? Page one of your schedule, DAM-1, I
18 assume that is.

19 A. 10.2 million or 10.2 percent? Oh, okay.
20 I see. Yes.

21 Q. And the post-refinancing annual cost is
22 10.0, at the bottom of your interest costs in your
23 schedule, page one of three, DAM-1? The last part
24 of that schedule shows interest costs and cost-of-
25 money basis off in the right-hand column.

1 A. Right.

2 Q. Okay. And the -- so you have 10.2 million
3 as pre-finance, post -- this is rounded off. Post-
4 finance is 10 million. Your net interest savings,
5 .2 million?

6 A. Right.

7 Q. Is this a huge savings?

8 A. At that time that was the -- at the
9 current market rates that was a significant
10 savings.

11 Q. This is a savings of \$231,000 per year to
12 refinance 100 million dollars in debt cost; right?

13 A. Right.

14 Q. You mentioned a reduction in the debt cost
15 by .275 percent. If I refinance a home at the cost
16 of 8 percent and I could save .275 percent, what
17 rate would I then have?

18 A. 7-point -- I don't know what --

19 Q. 7.975?

20 A. No. 7-point -- 7.625, I think. 8 percent
21 minus the 2.75.

22 Q. 8 percent minus the .275.

23 A. Right. So it would be whatever that
24 difference is, 7-point something.

25 Q. Okay. So it would be about 7.275, is that

1 it? On page 3 of your testimony, line 15, this
2 .275 percent, where does that number come from?

3 A. It is the difference between the total
4 found on page two of three in my exhibit, 9.65 at
5 the bottom, versus -- that's the pre-refinancing,
6 and then the post-refinancing shown on Exhibit 3
7 shows total embedded cost of 9.69 percent. That's
8 your 2.75 differential.

9 MR. BINEK: I have no further questions.

10 MR. HOBERG: Thank you, Mr. Binek. Mr.
11 Fahn, did you have any questions of Mr. Mahowald?

12 EXAMINATION

13 BY MR. FAHN:

14 Q. I'm sorry if I -- I'm sure I'm repeating a
15 question here, but I'm still not clear on page
16 three of your testimony. What's the difference
17 between -- okay. What -- you mentioned that the
18 pre-refinancing cost for the group was 10.215
19 percent.

20 A. Correct.

21 Q. Okay. What does that number include?

22 A. That's the average of the cost of money
23 found on Exhibit 1.

24 Q. DAM-1?

25 A. Yeah. Page 1. You've got page two there.

1 Q. And what is the difference between the
2 pre-refinancing cost for the group versus the
3 pre-refinancing coupon interest rate? What is that
4 in terms -- in English language what is the
5 difference?

6 A. The coupon rate would just be the sole
7 interest coupon on that debt. That's what we have
8 to pay someone who holds that debt. The cost-of-
9 money rate would include all the refinancing --
10 that would be our cost for all the refinancing
11 costs and the acquisition stuff that we had to
12 include in refinancing this debt.

13 Q. Okay. My only confusion, I guess, is that
14 it seems to me like if you -- it's just a
15 definition thing. It's the cost of obtaining the
16 financing back from previously what held it?

17 A. Right.

18 Q. Seems like it would be a post-cost instead
19 of a prefinancing cost.

20 A. Well, because we had refinanced some of
21 this debt in this '92 example because some of that
22 debt was already refinanced in '86, that's why the
23 10.215 is there because that is acquisition costs
24 that we incurred when we refinanced the debt
25 previously.

1 Q. Okay.

2 A. That's just reacquisition costs. It
3 continues to carry forward until this debt finally
4 matures.

5 MR. FAHN: Okay. Thank you.

6 MR. HOBERG: Thank you, Mr. Fahn.

7 Commissioner Wefald, do you have any questions of
8 Mr. Mahowald?

9

EXAMINATION

10 BY COMMISSIONER WEFALD:

11 Q. Why does it -- do you have an exhibit that
12 shows -- is the one on page three of three,
13 39,901,186, the one that shows your date of
14 maturity of all these different bonds?

15 A. As of December 31st, 1992, that was the
16 maturity at that time.

17 Q. So do you have an updated list that tells
18 us what the maturity dates are?

19 A. I have an updated list, but I don't have
20 one with me. I could prepare one and get one to
21 you if you'd like to see that.

22 COMMISSIONER WEFALD: That would be great.

23 MR. HOBERG: Okay. Mr. Pearce, can you
24 make that a late-filed exhibit to -- let's see.
25 What's the last exhibit on his --

1 MR. PEARCE: I believe the data is
2 actually in the record in one of Dr. Gaske's
3 schedules, JSG-2, Schedule 1, page two of two.
4 That would be part of Exhibit 7, I think -- or the
5 direct, Exhibit 6.

6 MR. HOBERG: The direct?

7 COMMISSIONER WEFALD: So that's already --

8 MR. PEARCE: That's already part of
9 Exhibit 6.

10 MR. HOBERG: Let's take a look. Do you
11 have -- what's --

12 MR. PEARCE: That's the bound book. It's
13 Exhibit 6, the MDU direct testimony.

14 MR. HOBERG: Okay. Do you have --

15 COMMISSIONER WEFALD: MDU direct.

16 MR. HOBERG: -- the direct of Dr. Gaske?

17 MR. PEARCE: If you look in his JSG-2, one
18 of his exhibits after the -- JSG-2, Schedule 1,
19 page two of two.

20 COMMISSIONER WEFALD: Page one of one.

21 MR. PEARCE: It looks like it's about
22 the --

23 COMMISSIONER WEFALD: Page two of two is
24 what you want me to look for?

25 MR. PEARCE: Right. Schedule 1 -- it's

1 JSG-2, Schedule 1, page two of two, and it's
2 entitled Montana-Dakota Utilities Co. Long-term
3 Debt Capital, December 31st, 2000. Looks like it's
4 just the second page after page 48.

5 MR. HOBERG: Are you finding it?

6 COMMISSIONER WEFALD: I found it.

7 MR. HOBERG: Is that what you're looking
8 for?

9 COMMISSIONER WEFALD: Mm-hmm.

10 Q. (COMMISSIONER WEFALD CONTINUING) Now I
11 need a little help in -- in understanding why
12 Montana-Dakota Utilities' debt is intermingled with
13 Montana-Dakota Resources' debt. Because yesterday
14 they said that 13-and-a-half percent -- one of the
15 people talked about 13-and-a-half percent of the
16 debt relates to Montana-Dakota Utilities --

17 A. Okay. The --

18 Q. -- but when I asked the question -- excuse
19 me, I'll just try to finish. But when I asked the
20 question about refinancing, they said that, well,
21 100 percent of the debt would have to be
22 refinanced. So now I'm asking you why that's the
23 case if only 13-and-a-half percent relates to the
24 utility?

25 A. Okay. The debt that we have for MDU

1 Resources evidenced by the first mortgage bonds --

2 MR. PEARCE: I'm handing Mr. Mahowald a
3 copy of the exhibit page from Dr. Gaske that we're
4 looking at.

5 MR. HOBERG: Thank you.

6 Q. (COMMISSIONER WEFALD CONTINUING) This
7 says Montana-Dakota Utilities Company's long-term-
8 debt capital. Is this the debt that only relates
9 to Montana-Dakota Utilities?

10 A. Correct. This is just MDU --
11 Montana-Dakota Utilities' debt.

12 Q. All right. So then do you think he erred
13 in answering my question, that 100 percent of
14 Montana-Dakota Resources' debt would have to be
15 refinanced in order to take care of Montana-Dakota
16 Utilities' debt?

17 A. No. We could refinance this debt here,
18 just the Montana-Dakota debt, if it was economical
19 to do, but at this time it's not economical to
20 refinance.

21 Q. Explain why it's not if it's --

22 A. It goes --

23 Q. This is 130 million --

24 A. 6.4 million.

25 Q. Where are you finding that number?

1 A. We've got the first mortgage bonds and
2 then we have some pollution control bonds,
3 pollution control notes.

4 Q. Is that \$136,450 figure the correct one?

5 A. Right. That's all Montana-Dakota
6 Utilities' debt.

7 Q. Okay. And so tell me why it isn't cost-
8 effective to refinance at this present time.

9 A. You could save some money in your interest
10 coupon rate because rates have come down a little
11 bit for some like -- for instance, the 8.25 and the
12 8.6, the interest coupon rate has come down. So we
13 could probably generate some annual savings there,
14 but because of the reacquisition costs -- in order
15 for us to get that debt back from the holders, we'd
16 have to pay them a significant cost, and we
17 wouldn't be able to -- we would immediately
18 increase the overall total cost of debt because
19 there wouldn't be enough savings in the coupon rate
20 to overcome the amount of acquisition or the price
21 we'd have to pay to get that debt back from
22 existing holders.

23 You know, we might be able to save a half-
24 million dollars in interest coupon rate alone, but
25 it would cost us probably a million dollars per

1 year amortized over 20 years to reacquire that
2 debt. So we would increase total costs by half a
3 million dollars a year by trying to refinance the
4 debt at this time.

5 Q. Do any of these debts relate to the power
6 plants that were built in 1982 or in the early
7 Eighties?

8 A. I would say the 8.25, the 8.6, those were
9 issued in '92, as you can see here, and those were
10 reissued as part of a refinancing for '86 debt,
11 which was -- which in '86 refinanced some of the
12 original '77, '78 bonds that we put on the books
13 for the plant.

14 Q. Those are at 8.25 and 8.6. Have you
15 looked at just refinancing those two alone?

16 A. Yes, we have, and it would -- for example,
17 the 8-point -- just for an example on the 8.6, you
18 could probably save one-and-a-half percent on the
19 coupon rate, which would be about \$500,000 a year
20 based on your principal amount.

21 Q. One-and-a-half percent on the coupon rate?

22 A. Right. We could probably issue that debt
23 for around seven percent.

24 Q. What rating are you right now with your
25 bonds?

1 A. A. We're a single A.

2 Q. Single A?

3 A. But in order to reacquire that 8.6 debt
4 based on a present-value fair-market estimate, it
5 would probably cost us 10 million dollars that we'd
6 have to pay to the existing holders to have them
7 tender that debt. So we would immediately -- it's
8 just not economical because we'd be saving over
9 500,000 a year, but we'd be paying at least a
10 million dollars a year to reacquire that debt at
11 these rates.

12 Q. And you don't -- that's the current rate
13 that's available for A?

14 A. Right.

15 Q. Triple A would be less; right?

16 A. Correct. Probably be maybe
17 six-and-a-half.

18 Q. Actually, it's five today. Someone called
19 me about buying a bond today. Triple A was five
20 percent.

21 A. Was that tax exempt or --

22 Q. Yes. It was tax exempt.

23 A. I was going to say, that seems kind of low
24 for a taxable issue.

25 Q. Anyway -- all right. Thank you. Now at

1 least I know that it -- that this is the debt that
2 relates directly to Montana-Dakota Utilities and
3 I'm not confused anymore about the whole --

4 A. Correct.

5 Q. -- corporation having to be refinanced in
6 order to take care of this particular debt.

7 A. Right. And we could refinance this at any
8 time if it was economical.

9 COMMISSIONER WEFALD: Thank you.

10 MR. HOBERG: Thank you, Commissioner
11 Wefald. Commissioner Reinbold, please.

12 COMMISSIONER REINBOLD: I have a question,
13 Mr. Mahowald.

14 EXAMINATION

15 BY COMMISSIONER REINBOLD:

16 Q. You said you were assistant treasurer and
17 assistant secretary of Montana Resources Group,
18 Inc.?

19 A. Yes.

20 Q. You're assistant to whom? Who is your --
21 who is your chief?

22 A. Warren Robinson.

23 Q. And he -- he's treasurer and secretary for
24 both --

25 A. Warren Robinson is the CFO. He's --

1 to recover those -- some costs that we used in
2 reacquiring that debt in '92.

3 Q. Is this -- the 40-million four-day loan
4 from the Bank of America, is that kind of a
5 separate issue? Is that more of an issue of what
6 gets counted as debt on the books?

7 A. Yes, I guess it would be.

8 Q. Okay. On that issue -- I just need a
9 little bit of help. I know you'd mentioned it, but
10 I forgot to get it down. The institutions that, in
11 your words, you're clearing the short-term lines
12 for, who are they again?

13 A. Well, it would be the ratings agency, S&P
14 and Moody's. They like to see that you're able to
15 demonstrate financial strength. Otherwise what'll
16 happen is that debt will be considered short-term,
17 which could affect our commercial paper ratings and
18 our bond ratings, and if they were to negatively
19 impact those ratings, our borrowing costs could go
20 up.

21 Q. And so that's the reason that they want
22 that 40 million there?

23 A. Right.

24 COMMISSIONER CLARK: Okay. That's all the
25 questions I have. Thank you.

1 COMMISSIONER WEFALD: I have one followup.

2 MR. HOBERG: Thank you, Commissioner
3 Clark. Commissioner Wefald, please.

4 FURTHER EXAMINATION

5 BY COMMISSIONER WEFALD:

6 Q. Then is that 40 million included in the
7 136 million?

8 A. No, it would not -- it's not in here. It
9 wouldn't be included.

10 COMMISSIONER WEFALD: It's not. Okay.
11 Thank you.

12 MR. HOBERG: Thank you, Commissioner
13 Wefald. Any further questions, Mr. Pearce?

14 MR. PEARCE: Just a couple extra.

15 REDIRECT EXAMINATION

16 BY MR. PEARCE:

17 Q. Mr. Mahowald, if the company can
18 demonstrate that it can obtain a term loan, say,
19 for 40 million dollars in an amount sufficient to
20 pay your commercial paper, that would demonstrate
21 financial integrity and strength to the rating
22 agencies, wouldn't it?

23 A. Yes. In fact, it -- yes.

24 Q. Now I think there was some question about
25 the agreement to Mr. King's use of 1.3 million

1 dollars with this term loan we're talking about.

2 Is it your understanding that MDU agreed to use the
3 average daily balance of that term loan, and that
4 was 1.3 million dollars? Does that sound right?

5 A. Yes.

6 Q. And, of course, if there's an actual
7 outstanding obligation of 40 million dollars at the
8 end of the year, the company's obligated to report
9 that on the appropriate reports it would make of
10 outstanding obligations?

11 A. Yes.

12 Q. Now there was a question about Otter
13 Tail's share in the Coyote plant built back in the
14 1970s. You wouldn't have any information, I
15 assume, as to what kind of financing Otter Tail
16 might or might not have needed to finance its
17 share, would you?

18 A. No.

19 Q. You have never worked for Otter Tail, have
20 you?

21 A. No.

22 Q. Can I assume that you would not agree with
23 Mr. King's characterization of MDU's current cost
24 of debt as unreasonably high?

25 A. No, I would not agree with his

1 characterization.

2 Q. How would you characterize it?

3 A. If you look at Dr. Gaske's testimony, his
4 rebuttal testimony on page -- oops, this is not the
5 right book. On page three of Dr. Gaske's rebuttal
6 testimony --

7 MR. HOBERG: That would be Exhibit 7.

8 THE WITNESS: -- we have issued some debt
9 since '92, since this refinancing, and if you look
10 at that, our long-term debt issued after April 1992
11 has an average cost of 7.31 percent, and that is
12 lower than the 7.68 percent debt cost of Otter Tail
13 Power that Mr. King cites in his rebuttal testimony
14 and very close to Northern States Power's 6.99
15 percent long-term debt cost that he cites. So I
16 think the company's been very prudent in obtaining
17 the least-cost debt. Unfortunately, the '92 debt
18 that is still on the books has a lot of
19 reacquisition costs, and we're just not able to
20 economically refinance it at this time.

21 MR. PEARCE: I have no further questions.

22 MR. HOBERG: Thank you, Mr. Pearce. Mr.
23 Binek, anything further of Mr. Mahowald?

24 MR. BINEK: Yes.

25

1 RE CROSS-EXAMINATION

2 BY MR. BINEK:

3 Q. Getting back to this 40-million-dollar
4 loan, you said they -- I forget. I don't know
5 exactly how you said it, but you said that they
6 want you to be able to show you have the capacity
7 to clear your short-term debt or something like
8 that. Who's "they"?

9 A. It's the rating agencies, because what we
10 do is when we -- we have a commercial paper program
11 at MDU, and that commercial paper program is backed
12 by a standby letter of credit issued by various
13 banks, and the only way we can really sell
14 commercial paper to investors, you have to have a
15 standby letter of credit because if for some reason
16 we had 40-million-dollars commercial paper
17 outstanding today and we couldn't access the
18 market, September 11th came or we just couldn't
19 sell our paper, those investors would want to be
20 paid back. So we would have to then go into our
21 standby letter of credit and borrow to repay those
22 commercial paper investors, and the rating agencies
23 like to see that you clean out -- or clear your
24 lines so you can demonstrate that you have the
25 financial capacity to do that, and that determines

1 your short-term credit rating.

2 Q. Okay. So then was it the rating agencies
3 that told you you needed to do this or who --
4 who -- who made this determination?

5 A. It's driven by the rating agencies and
6 their requirements.

7 Q. But who determined -- who said borrow 40
8 million dollars for four days?

9 A. Well, we had -- at that time we had some
10 short-term debt outstanding, and we -- to
11 demonstrate to the rating agencies that we have the
12 capacity under the back-up lines to access credit,
13 we paid that debt -- we moved that debt from
14 short-term over into the term loan.

15 Q. Okay. And who decided to include the full
16 40 million dollars as term debt -- or I think the
17 term is what you -- you called it.

18 A. It was based on our borrowing --
19 short-term borrowings at that time. We just took
20 the full amount and moved it over.

21 Q. Okay. And if I understood the exchange
22 between you and Mr. Pearce, it sounds to me like
23 you agree that this 40 million dollars has been
24 removed from your overall debt and there's 1.3
25 million being shown.

1 A. Correct.

2 Q. Do you agree with that?

3 A. Yeah.

4 Q. Okay. So my point again is the report
5 that you provided or that MDU provided to Mr. King
6 that showed 170-some million dollars in overall
7 debt was incorrect, that that was overstated by
8 38.5 million?

9 A. I haven't seen that exhibit, so I can't --
10 I don't know. I'll take your word for it, but I
11 haven't seen the exhibit. I guess I'd have to see
12 the exhibit to agree with that.

13 Q. Okay. And can you tell me or not -- do
14 you know who -- who made the determination to
15 include that 40 million dollars in the overall
16 debt?

17 A. That I don't know.

18 Q. Okay. Are your records audited by any
19 outside auditing company?

20 A. Arthur Andersen.

21 Q. Okay. This is Arthur Andersen of Enron
22 fame?

23 A. Well, yes. Yes.

24 Q. Okay. And they approved this showing of
25 178 million dollars in debt, overall debt?

1 MR. HOBERG: It's in Exhibit 3.

2 Q. (COMMISSIONER WEFALD CONTINUING) And I'm
3 sure -- I just need to understand then how these
4 numbers are arrived at. Under debt staff shows
5 8.62 percent cost of debt, and then it says
6 Montana-Dakota Utilities Company, and I believe
7 that's the cost of debt that MDU is stating in this
8 case.

9 A. Correct.

10 Q. But when I look at the numbers that you
11 referred me to on JSG-2, none of those interest
12 rates are above 8.6, and so I'm having difficulty
13 understanding how -- there must be something wrong
14 here -- why the cost of debt would be 9.22 percent.
15 So just explain to me how --

16 MR. PEARCE: Perhaps if I could interject.
17 I don't want to testify for the witness, but the
18 JSG-2, Schedule 1, page one of two, shows how the
19 capital structure and debt works together to end up
20 with the embedded cost.

21 MR. HOBERG: Is that what you're looking
22 at, Mr. Mahowald?

23 THE WITNESS: I am now, right.

24 MR. HOBERG: Okay.

25 Q. (COMMISSIONER WEFALD CONTINUING) What's

1 the difference between what you're showing on page
2 one, Schedule 1, and what's being shown on Schedule
3 1, page two of two? How about -- which of those
4 numbers on Schedule 1, page one of two, relates to
5 the next page that you referred me to?

6 A. Not preparing this exhibit, I'd have to
7 defer that to Dr. Gaske. I'm not sure.

8 MR. HOBERG: Mr. Binek, Mr. Pearce, do you
9 mind if Dr. Gaske, who's already been sworn, goes
10 up to answer this question --

11 MR. PEARCE: That's fine.

12 MR. HOBERG: -- since he's the appropriate
13 person?

14 MR. PEARCE: Sure. That makes sense, if
15 you're agreeable.

16 MR. BINEK: That's fine.

17 MR. HOBERG: Dr. Gaske, do you want to
18 approach the stand and see if you can help us out
19 with that question, please? Do you understand the
20 question, Dr. Gaske?

21 DR. GASKE: Yes, I do.

22 MR. HOBERG: Okay.

23 COMMISSIONER WEFALD: I just need to know
24 how to relate the figures.

25 DR. GASKE: Right. If you look at

1 Schedule 1, page one, on the very top line it
2 refers to long-term capital.

3 COMMISSIONER WEFALD: Yes.

4 DR. GASKE: The balance outstanding -- the
5 numbers on that line are a summary of what you see
6 on page two of that schedule.

7 COMMISSIONER WEFALD: And I see that
8 number at the bottom of that page.

9 DR. GASKE: Right. You'll see the -- all
10 three of those numbers appear on the very bottom
11 line of page two.

12 COMMISSIONER WEFALD: All right. Then
13 when we were talking about the first group,
14 \$136,450,000, then what's the second group of
15 numbers then, 130,850,000, because those have much
16 higher debt levels? The cost of money is much
17 higher.

18 DR. GASKE: That's correct. The cost of
19 money is a combination of the coupon interest
20 rates, which you see up positive and also in the
21 title to most of the bonds. If you go over to sort
22 of the upper right-hand block of numbers on the
23 page, you have "Underwriters' Commission," and
24 you've got "Loss on Reacquirement, Redemption and
25 Issuance Expenses." Those carry down then into the

1 bottom half of the page where the company has
2 calculated the effect of cost of money.

3 So, for example, the 8.25 percent first
4 mortgage bond has a total cost of 10.17 percent
5 once you include the underwriters' commissions and
6 the reacquisition costs. The overall average for
7 all of the debt way down in the lower right-hand
8 corner of the page, 8.938, carries over then to the
9 first page.

10 COMMISSIONER WEFALD: I see. Okay. Thank
11 you very much. That's been very helpful.

12 DR. GASKE: Did you want to follow up on
13 why 9.22 seems to pop out or --

14 COMMISSIONER WEFALD: Well, then there's
15 an additional 10 million of commercial paper. What
16 is that?

17 DR. GASKE: Commercial paper is very
18 short-term loans that companies typically issue.
19 They'll --

20 COMMISSIONER WEFALD: Is that like this
21 one that they were talking about for 40 million
22 dollars for four days?

23 DR. GASKE: No. It would be paper that
24 they actually issue out in the market. It might
25 be -- I guess Mr. Mahowald probably can tell you

1 the components of it, but it might be 30 days, 60
2 days, 6 months, something like that, but there's --
3 there are a couple of items when you look at the
4 annual cost column, the second line has \$548,000 of
5 amortizations. So that would tend to increase the
6 overall costs that you end up with way down at the
7 bottom. The 9.22 percent includes that.

8 COMMISSIONER WEFALD: Thank you.

9 DR. GASKE: Okay.

10 MR. HOBERG: Thank you, Dr. Gaske.

11 Anything further of Mr. Mahowald?

12 COMMISSIONER WEFALD: No.

13 MR. HOBERG: Thank you. Commissioner
14 Clark, anything further?

15 COMMISSIONER CLARK: No further questions.

16 MR. HOBERG: Any further questions of Mr.
17 Mahowald? Thank you, Mr. Mahowald. Okay. Mr.
18 Pearce, I think you have three witnesses left?

19 MR. PEARCE: Yes.

20 MR. HOBERG: Should we take a recess here
21 and come back at 1 o'clock? Does that sound
22 appropriate?

23 COMMISSIONER CLARK: I think so, unless
24 we've got one that's real quick.

25 MR. HOBERG: Probably don't have one

1 that's that quick.

2 MR. PEARCE: Probably not. There may be a
3 number of questions of Mr. Espeland.

4 MR. HOBERG: Okay. Let's stand in recess
5 till one o'clock, promptly at one o'clock.

6 (Noon recess taken.)

7 MR. HOBERG: Okay. We're back from
8 luncheon recess, and just for the purposes of a
9 clean record, Mr. Mahowald's testimony we took just
10 before lunch was Docket No. 62, Exhibit 7. I
11 believe we're about to move on to Mr. Espeland.

12 MR. PEARCE: Yes.

13 MR. HOBERG: Would you please call him?

14 MR. PEARCE: I'll call Richard A.
15 Espeland.

16 MR. HOBERG: And while he's walking up,
17 I'll just refer to his testimony as Docket No. 58,
18 also surrebuttal testimony found in Exhibit 7. Mr.
19 Espeland, did you hear the admonition I gave in
20 regarding to perjury earlier today?

21 THE WITNESS: Yes, I did.

22 (Witness sworn.)

23 MR. HOBERG: Thank you. Mr. Pearce,
24 please.

25

1 UND in 1996 with a marriage in personnel management
2 and subsequently received my Master's degree in
3 public administration from UND in 1981.

4 Upon graduating from college I spent 4
5 years in the U.S. Army as an officer in the
6 infantry, and then I worked 2 years with the City
7 of Grand Forks, 5 years with the State of North
8 Dakota, 12 years with North American Coal
9 Corporation, and currently 12 years with MDU
10 Resources Group.

11 In December of 1989 I did join MDU
12 Resources as human resources manager and held that
13 position until August 2000 when I was elected vice
14 president of human resources.

15 I'm currently a member of the Human
16 Resource Management Society and the Central Dakota
17 Human Resource Association. I have spoken on
18 retirement and employee benefit issues on many
19 occasions at national conferences in Boston,
20 Orlando, Chicago and San Francisco.

21 Q. I may have misheard, but did you say
22 possibly that you received your BA degree in 1996?
23 I think you meant '66.

24 A. Did I say '96? I may have. '66, as the
25 written testimony shows.

1 Q. What is the purpose of your testimony
2 today?

3 A. The purpose of my testimony is to address
4 the rebuttal testimony of Mr. Mike Diller of the
5 Commission staff in this case concerning the
6 supplemental income security plan, or SISP, and to
7 further explain the purpose of SISP as it was
8 originally addressed by Mr. Don Ball of
9 Montana-Dakota in his direct testimony.

10 Q. What are your duties and responsibilities
11 relative to the SISP program?

12 A. I am the plan administrator assigned the
13 responsibility by the board of directors of MDU
14 Resources Group for the management of the plan,
15 design of the plan, eligibility, interpretation,
16 communication and benefits administration.

17 Q. At page 16, line 7 of his testimony, Mr.
18 Diller mentions that the SISP has been in effect
19 since 1982 but that Montana-Dakota has not
20 previously sought rate recovery. Would you please
21 explain why that is?

22 A. Yes, I will. When the SISP was
23 implemented in 1982, it was a visionary plan and
24 was new to the utility industry and many industries
25 at that time. It was not common anywhere within

1 the utility industry in 1982. In the intervening
2 years since then, and particularly in the last few
3 years, supplemental employee retirement plans,
4 which are commonly called SERPs, which are like
5 Montana-Dakota's SISP, have become common practice
6 both in utilities and related companies.

7 These types of plans have become necessary
8 due to various changes in federal regulations,
9 Social Security benefits and employment practices.
10 These changes have adversely affected
11 Montana-Dakota's key employees as to potential
12 retirement benefits. Because of those changes,
13 SERPs, such as Montana-Dakota's SISP, have become
14 necessary in order to attract, retain and provide
15 equitable benefits for key employees. The SISP
16 costs therefore should be included in
17 Montana-Dakota rates.

18 Q. Would you please describe the various
19 changes in federal regulations that have adversely
20 affected retirement plans for key employees?

21 A. In the early Eighties prior to SISP being
22 implemented, a defined benefit pension plan like
23 Montana-Dakota has could provide benefits in
24 consideration of up to \$225,000 of salary. That
25 limit was reduced in the mid Eighties to \$150,000

1 of salary that could be considered in a defined
2 benefit pension plan, therefore reducing the
3 benefit eligibility and pension benefits provided
4 by about one-third.

5 This compensation limit has slowly
6 increased to the current \$200,000 level but is
7 certainly not at a pace equal to general wage
8 inflation. In addition, the 401(k) plan
9 regulations limit employee contributions to
10 \$11,000. The effect is that the employee with a
11 \$50,000 annual income can contribute 22 percent of
12 their salary while senior executives are generally
13 limited to 10 percent or less.

14 Q. What changes in Social Security benefits
15 have adversely affected key employees?

16 A. The Social Security covered wage base,
17 while increasing over the years, has not kept pace
18 with the general wage inflation, and benefits
19 provided to higher income levels are significantly
20 less than at lower income levels.

21 Q. At page 16, line 12 of his testimony, Mr.
22 Diller notes that Montana-Dakota participants in
23 the SISP have declined from 38 participants in 1996
24 to 27 participants in 2001. He suggests that the
25 reduction may indicate that Montana-Dakota no

1 longer sees the same need for this plan. Is there
2 a reason for the decline in SISP participants?

3 A. Yes, there is a reason. Montana-Dakota
4 has taken aggressive action since 1995 to reduce
5 costs and to streamline their organization and
6 provide the lowest cost to the consumer. As a
7 result of these actions, Montana-Dakota was able to
8 reduce the number of management positions as well
9 within their company and thus reduce the number of
10 SISP participants.

11 Q. Who are the key employees you refer to who
12 are participants in SISP?

13 A. Key employees are officers, directors and
14 senior managers of MDU Resources and Montana-Dakota
15 who have the vision to adequately plan for the
16 future, implement appropriate strategies for the
17 company, and see how to reduce costs, streamline
18 the organization, and implement new technologies to
19 maintain and increase efficiencies of the company
20 with fewer employees while keeping the rates stable
21 and competitive within the industry. A perfect
22 example is the fact that Montana-Dakota has not had
23 to seek an electric rate increase in the last 15
24 years.

25 Q. Mr. Diller at page 16, line 19 of his

1 rebuttal testimony expresses concern that there is
2 a lack of symmetry in the SISP in that an employee
3 making \$50,000 per year would receive a lower
4 percentage of annual income than a higher income
5 employee. Would you please explain the difference?

6 A. Yes, I will. When the compensation and
7 benefit programs are designed, we look at them in
8 the context of all of the benefit programs, all of
9 the retirement benefit programs specifically. To
10 put the retirement benefits in perspective, I have
11 prepared Exhibit RAE-1, which reflects the
12 retirement programs available to employees in
13 Montana-Dakota, including the SISP.

14 As you will note from the graph, at the
15 lower income levels the replacement income through
16 retirement programs is about 80 percent. This
17 includes Social Security, the defined benefit
18 pension plan, the company match to the employee
19 contributions to the (k) plan, and as you move up
20 the scale, the percentage of income replaced by
21 retirement plans of these three decreases
22 significantly based on the retirement plan design
23 requirements and the government limitations.

24 The SISP as a supplemental plan has been
25 designed to replace some, but not all, of the

1 income that is not replaced by Social Security,
2 defined benefit pension and the 401(k) plan. At
3 the higher income levels we target only about 50
4 percent of the annual income being replaced
5 compared to 80 percent at the lower income levels.

6 Q. Does the SISP benefit last as long as the
7 other retirement benefits you've noted?

8 A. No, it does not. The retirement benefits
9 payable under SISP are payable over 15 years
10 beginning at age 65 and not over the remaining
11 lifetime of the individual, which is currently
12 about 20 years for the defined benefit pension,
13 Social Security and the like. So Social Security,
14 the defined benefit pension, and the 401(k) plan
15 income projections cover the entire -- the
16 retiree's lifetime versus just the first 15 years.

17 Q. Should Montana-Dakota's SISP be included
18 in rates?

19 A. Yes, it should be. The SISP is a common
20 type of benefit provided in today's business
21 environment. The combined replacement income from
22 all retirement plans when taken together is
23 equitable, reasonable and justifiable. The SISP
24 recognizes the contributions of key employees whose
25 abilities and vision have enabled Montana-Dakota to

1 streamline operations, reduce costs and employee
2 numbers, implement new technologies and, more
3 importantly to the ratepayer, to keep
4 Montana-Dakota's electric rates at 1987 levels at a
5 time when the Consumer Price Index rose 59 percent
6 during the same period of time.

7 Q. Looking at the question of the security of
8 the SISP benefits, is that the same as for the
9 company's other retirement plans?

10 A. It is not. It's significantly different.
11 The SISP is a non-qualified benefit plan, which
12 means it is not secured by Pension Benefit
13 Guarantee Corporation. It's only backed by the
14 assets of the corporation itself or by
15 Montana-Dakota Utilities. So the significant
16 difference is if the company was to go bankrupt or
17 become insolvent, there would be no money to pay
18 benefits to these executives under the SISP because
19 those moneys would first go to creditors.

20 Whereas in a defined benefit pension plan,
21 those are separated in a trust, guaranteed by the
22 Federal Government, as well as the funding within
23 the trust, and are available no matter what happens
24 to the company, the general employees. And I might
25 add that is by design. We want the supplemental

1 income retirement program to be at risk so that the
2 executives have an incentive to maintain the
3 company as a viable organization.

4 Q. You stated the SISP is necessary to
5 attract and retain key employees. Is this just
6 your theory or your hope, or do you have real-life
7 experiences with this?

8 A. We have real-life experiences. You know,
9 I can give a couple examples in recent times of --
10 in power production we had a very young crew in our
11 power plant area. We went to the outside to hire
12 someone that had a lot of experience in the Midwest
13 region. We hired a very experienced person that
14 has been able to coach and develop our current
15 employees to be able to have that seasoned
16 experience. If it had not been for SISP's benefit,
17 we would not have been able to attract that
18 individual. Same with -- and we recently hired a
19 vice president of human resources for Montana.
20 Again, without SISP we would not have been able to
21 get the expertise and the background to really come
22 in and make a difference.

23 Q. In your opinion then, the existence of a
24 program like SISP provides a real benefit to
25 ratepayers?

1 that the costs of this plan have never been
2 included in rates.

3 A. That's correct.

4 Q. And you gave some explanation of why you
5 think that this benefits the ratepayers and why the
6 costs should now be borne by ratepayers. Are you
7 saying or suggesting that MDU's shareholders do not
8 benefit from the efforts of these key employees?

9 A. Well, they certainly do. Yeah. Both
10 ratepayers and stockholders benefit.

11 Q. But you want the ratepayers to pay the
12 full cost of this; right?

13 A. I think it's an appropriate cost, just
14 like their salaries are. It's a part of the total
15 compensation package.

16 Q. But we're talking about key employees, 27
17 key employees that are doing all these wonderful
18 things for the company, and you want the total cost
19 to be paid by the ratepayers, even though you say
20 that the shareholders benefit?

21 A. Well, I think -- yes. I think it's an
22 appropriate cost of doing business to have the
23 talents at any level within the organization.

24 Q. You state that these types of plans have
25 become necessary due to various changes in

1 regulation, Social Security benefits, and
2 employment practices and that those changes have
3 adversely affected MDU's key employees as to
4 potential retirement benefits. I'd like to have
5 you provide a list -- or give us a list of the
6 retirement benefits that are presently available to
7 these key employees.

8 A. A list of their retirement benefits?

9 Q. Right.

10 A. That is summarized on the graph, which was
11 Exhibit RAE-1, which lists those four sources of
12 retirement benefits, Social Security, 401(k) plan,
13 the pension, and the SISP. Those are the four
14 retirement programs we have.

15 Q. What other benefits does MDU provide to
16 these key employees?

17 A. The same benefits that we provide to all
18 other employees, healthcare, life, disability.

19 Q. I'd appreciate it if you'd give us a list
20 of those.

21 A. Okay. We have healthcare, which includes
22 medical and dental, with cost-sharing by the
23 individuals. We have life insurance available
24 uniformly to all employees to include the key
25 executives. We have holidays, vacations, we have a

1 sick leave program, long-term disability program.

2 I'm trying to think of what I'm forgetting.

3 Q. Are there some post-retirement benefits?

4 A. Yeah, retiree healthcare.

5 Q. Is there a benefit of -- still in place of
6 reduced utility rates for employees?

7 A. Yes. For employees that are -- reside in
8 the utility area that provides service, they get a
9 utility discount.

10 Q. How much is that?

11 A. I believe it's about one-third of the
12 utility.

13 Q. And that -- key employees also get that,
14 don't they?

15 A. That's correct.

16 Q. What's the annual cost of this
17 supplemental income security plan?

18 A. For the Montana-Dakota Utility electric
19 side it's about \$680,000, 600 -- I think that's
20 right, \$680,000.

21 Q. What's the total cost of the plan?

22 A. Total cost corporatewide?

23 Q. Right.

24 A. About two-and-a-half to three million.

25 Q. That's an annual cost?

1 A. That's an annual cost.

2 Q. And there are 27 employees?

3 A. No.

4 Q. Okay. How many employees -- there are 27
5 employees -- well, the 27 employees, is that just
6 Montana-Dakota Utilities?

7 A. That's correct.

8 Q. This 600-some-odd-thousand, is that just
9 North Dakota's share?

10 A. Yes.

11 Q. Okay. So the total -- what is the total
12 cost of the Montana-Dakota Utilities plan?

13 A. Both gas and electric?

14 Q. Whatever the --

15 MR. DILLER: Just electric.

16 Q. (MR. BINEK CONTINUING) Whatever these 27
17 employees are?

18 A. Okay. The cost to Montana-Dakota total,
19 gas and electric, would be about 1.2 million.
20 There's 27 active participants, but also there are
21 34 inactive, deferred, vested participants which
22 those costs also are funding those costs because
23 they have worked for us or they're retired and you
24 still have that cost, just like our defined benefit
25 pension plan. Our defined benefit pension costs

1 include not only active employees but all those
2 that are retired and the ongoing costs to fund
3 those benefits, as well. So we have about 60 total
4 participants for Montana-Dakota in SISP, former and
5 current, for that 1.2 million.

6 Q. And with roughly 60 employees, 1.2
7 million, you're talking about \$20,000 a year per
8 employee for --

9 A. The cost is about 20,000 a year. Correct.

10 Q. You talked about the total number of
11 employees being covered by this being 60. Haven't
12 those -- the costs for these prior employees been
13 funded previously?

14 A. No. Since it's a non-qualified plan,
15 there is no provision specifically for prefunding
16 and setting aside moneys. We do have a SISP -- or
17 a rabbi trust that some moneys go into, but it is
18 not fully funded like our defined benefit pension
19 plan. There is no -- there is -- about probably 20
20 or 30 percent of the liability has some dollars set
21 aside to it, but again those dollars are available
22 to creditors first. So they're not totally set
23 aside like a defined benefit pension plan.

24 Q. But this plan -- since 1982 money's been
25 going into this plan; right?

1 A. That's correct.

2 Q. Every year?

3 A. That's correct.

4 Q. And we're talking about right now 1.2
5 million a year. The benefits being paid out aren't
6 being paid out to 60 employees.

7 A. Montana-Dakota has about 20 employees in
8 pay status at various levels that can take partial
9 or they can take full. So we have about 20
10 individuals in a pay status. They don't have to
11 take it all at one time. The average cost is about
12 20,000 per year.

13 Q. Over the 60?

14 A. Over the 60.

15 Q. Of the 20 current employees what's the
16 average cost?

17 A. Of the 27? If you divide that way, it's
18 about 40,000, you know, but that's not reflecting
19 the full number of people covered, and that's --
20 that 680,000 also includes the cost of paying
21 current benefits and recognizing the cost of future
22 benefits, and so it's everything in there.

23 Q. And you said you're one of the key
24 employees?

25 A. Yes, I am.

1 Q. Will you resign your position if this
2 benefit is eliminated?

3 A. No.

4 Q. Isn't it true that even if the Commission
5 does not allow the cost of this plan to be
6 recovered in rates, the shareholders can still
7 continue to provide the benefit at shareholders'
8 expense just like it has been up to now?

9 A. I'd have to answer yes because the quality
10 and the type of management and employees we have
11 are going to do the best job they can regardless of
12 whether they feel they're paid fairly or treated
13 fairly. That doesn't make it necessarily the
14 appropriate way to establish rates. So, yeah,
15 they're going to continue to do a very good job.
16 That's just their nature.

17 Q. On page 5, beginning at line 14, you talk
18 about replacement income through retirement
19 programs, and you state that at the lower income
20 levels the replacement income through retirement
21 programs is about 80 percent, and as you move up
22 the income scale, the percentage of income replaced
23 by these plans significantly decreases. The 27
24 employees that we're talking about are the higher-
25 income employees obviously.

1 A. That's correct.

2 Q. Aren't these employees in a much better
3 position than lower-income employees to build up
4 savings and other stock portfolios and other
5 investments for their retirement?

6 A. Yes, they are. They have much more
7 discretionary income than the lower income, and
8 that's why we decline the replacement income to 50
9 percent rather than at the 80 percent level.

10 MR. BINEK: I have no further questions.

11 MR. HOBERG: Thank you, Mr. Binek. Mr.
12 Fahn, did you have any questions of Mr. Espeland?

13 EXAMINATION

14 BY MR. FAHN:

15 Q. Did you indicate anywhere in your
16 testimony what the -- I assume that your Exhibit
17 No. RAE-1, that would be annual salary levels on
18 the bottom of the chart?

19 A. Right. Annual compensation.

20 Q. And what is the -- of the key employees
21 you're talking about, what would the lowest annual
22 salary be possibly?

23 A. The ones included would be around 75 to
24 80,000.

25 MR. FAHN: 75 to 80. Okay. That's all I

1 have. Thank you.

2 MR. HOBERG: Thank you, Mr. Fahn.
3 Commissioner Wefald, please.

4 COMMISSIONER WEFALD: I have no questions
5 for this person.

6 MR. HOBERG: Thank you. Commissioner
7 Clark, please. I'm sorry. Commissioner Reinbold.

8 COMMISSIONER REINBOLD: I have no
9 questions.

10 MR. HOBERG: Commissioner Clark, please.

11 COMMISSIONER CLARK: I do have just a
12 couple.

13 EXAMINATION

14 BY COMMISSIONER CLARK:

15 Q. Maybe it would be helpful for me just
16 to -- and I understand kind of what it is in
17 general, but could you talk about in specifics how
18 does the SISP work?

19 A. Okay. SISP was designed so that we can
20 provide a supplemental retirement benefit at age
21 65. It is funded -- or we fund it through
22 corporate-owned or trust-owned life insurance
23 policies. Currently they're through Northwestern
24 Mutual Life because they have a cash value buildup
25 which offsets our cost, and the benefit there, as

1 well, is that if the executive were to die during
2 the lifetime, their working career, they would have
3 a life benefit or death benefit for a surviving
4 spouse. But generally it's funds or retirement at
5 age 65 for 15 years based on replacement, and the
6 costs of the program are paid out of corporate
7 funds and the proceeds come in to corporate assets.

8 Q. If someone were to retire at, say, 70, is
9 it 15 years after retirement date or is it 15 years
10 after 65?

11 A. Okay. It's 15 years from the date they
12 start receiving benefits. Now at age 65 if they
13 say I don't need it right now, I would like to
14 defer that for 5 years because I'll live till 90 or
15 100, they can do that.

16 Q. Okay. You talked about -- in response to
17 a question that Mr. Binek had about other additions
18 that employees -- or other additions, kind of other
19 benefits that employees get. You talked about this
20 utility discount of about a third or something.

21 A. That's correct.

22 Q. Is that to all employees, including
23 current ones, or is that just to retirees?

24 A. No. That's to all employees.

25 MR. HOBERG: Excuse me. You need to get a

1 little closer to the mike.

2 THE WITNESS: I'm sorry. That is to all
3 employees.

4 Q. (COMMISSIONER CLARK CONTINUING) Okay.
5 All employees get this third discount or however
6 it's figured. The income that's not realized
7 there, it has some sort of cost, does that come
8 from shareholder or ratepayer side of the equation?

9 A. The discount is included in prior rate
10 filings, I believe.

11 Q. So that would be included prior to rate
12 filings. In other words, it comes from
13 shareholder -- it comes on the ratepayer side?

14 A. It's my understanding from the design of
15 it, that all costs are covered in the -- you know,
16 in the cost the employee pays, but there is no
17 additional costs incurred there, but I would have
18 to defer to Don Ball on the specifics.

19 COMMISSIONER CLARK: Okay. I'll maybe ask
20 Mr. Ball when he gets up here. That's all I have.
21 Thanks.

22 MR. HOBERG: Thank you, Commissioner
23 Clark. Anything further? Commissioner Wefald?

24 COMMISSIONER WEFALD: I just had a
25 question.

EXAMINATION

1

2 BY COMMISSIONER WEFALD:

3 Q. Is Mr. Ball going to be covering the
4 pension and post-retirement issues that are
5 separate from SISP?

6 A. I believe he is, yes.

7 COMMISSIONER WEFALD: Thank you.

8 MR. HOBERG: Mr. Pearce, anything further
9 for Mr. Espeland?

10 MR. PEARCE: No.

11 MR. HOBERG: Anyone have anything further
12 for Mr. Espeland?

13 MR. BINEK: Yes. I just have a question.

14 MR. HOBERG: Mr. Binek.

15 RE-CROSS-EXAMINATION

16 BY MR. BINEK:

17 Q. It's a followup from Commissioner Clark's
18 question when he asked about these discounts. I
19 think he asked if they were also available to
20 retirees, and you said to all employees. Are you
21 including retired employees?

22 A. Yes. Those that live in the service
23 territory.

24 Q. Okay. So that continues on after they
25 retire? They still get that utility discount?

1 A. That's correct.

2 MR. BINEK: Thank you.

3 MR. HOBERG: Anything further then of Mr.
4 Espeland? Thank you, Mr. Espeland.

5 THE WITNESS: Thank you.

6 MR. PEARCE: Call Donald Ball.

7 MR. HOBERG: Mr. Ball, please. Mr. Ball,
8 I believe you heard the admonition I gave in regard
9 to perjury earlier; is that correct?

10 THE WITNESS: I did.

11 (Witness sworn.)

12 MR. HOBERG: Thank you. Mr. Pearce,
13 please.

14 DONALD R. BALL,
15 having been first duly sworn, was examined and
16 testified as follows:

17 DIRECT EXAMINATION

18 BY MR. PEARCE:

19 Q. Would you please state your name, business
20 address and position?

21 A. My name is Donald R. Ball. My business
22 address is 400 North Fourth Street, Bismarck, North
23 Dakota, 58501. I'm the director of regulatory
24 affairs of Montana-Dakota Utilities Company, a
25 division of MDU Resources Group.

1 Q. And you have previously filed some direct
2 testimony in this proceeding, have you not?

3 A. Yes, I have.

4 Q. What is the purpose of your testimony
5 today?

6 A. The surrebuttal testimony -- the purpose
7 is to address concerns I have with the rebuttal
8 testimony of staff witness Mike Diller in the areas
9 of the Mid-Continent Area Power Pool, or MAPP,
10 penalty, pension costs, insurance costs and office
11 supplies and expenses.

12 Q. Would you please explain your concerns
13 with Mr. Diller's treatment of the MAPP penalty
14 costs?

15 A. Yes. At pages 11 and 12 of his rebuttal
16 testimony Mr. Diller discusses his reasons for not
17 allowing the MAPP penalty costs. He indicates that
18 the Commission should not encourage further
19 penalties in the future by granting rate recovery
20 and that the Commission should assume that
21 appropriate reserve margins will be maintained and
22 no additional penalties will be incurred. He
23 eliminates about \$458,000 of penalties that were
24 included in 2001 results.

25 I would note at the outset that

1 Montana-Dakota, through its extensive planning and
2 forecasting activities, makes every effort to
3 ensure that it has adequate capacity to meet the
4 reserve obligation for serving retail customers.
5 There are a number of employees involved in the
6 process and the latest state of the art tools and
7 techniques are used. The load forecasting process
8 is described in detail in Section 2 of the
9 integrated resource plan filed with the Commission
10 on July 1, 2001.

11 Despite Montana-Dakota's best efforts at
12 forecasting peak load and resulting reserve
13 obligation, it fell short of capacity to meet the
14 reserve obligation in the summer seasons of 2000
15 and 2001 due to higher than normal temperatures at
16 the time of the peak and incurred penalties. I
17 should note that the 1999 penalty mentioned by Mr.
18 Diller was for only 0.9 megawatts, a very small
19 difference.

20 Application of hindsight indicates that
21 Montana-Dakota should have acquired more capacity
22 during these periods, particularly in 2001, to
23 avoid the penalties. As I explained above,
24 Montana-Dakota makes every effort to assure that it
25 has adequate reserve margin to avoid any penalty.

1 However, with the disallowance of all costs related
2 to the penalty that was incurred and the update to
3 the 2001 actual information, the staff position now
4 has sales levels and expense levels reflective of
5 2001 results but has no costs included for the
6 added capacity that was required to achieve those
7 results. This is an obvious mismatch that should
8 be corrected.

9 The Commission should include, as a proxy
10 for capacity that would have been purchased for the
11 summer of 2001, an amount representative of what
12 the cost would have been for added capacity that
13 would otherwise necessarily have been purchased to
14 avoid the penalty. Montana-Dakota, had it known
15 that it would be deficient in 2001, would have
16 purchased additional capacity for the four months
17 of June, July, August and September 2001 as it is
18 now planning on doing for 2002. However, the
19 precise cost of that capacity is not known.

20 Based on bids received by Montana-Dakota
21 for capacity purchases planned in 2002, the cost
22 for additional capacity is \$4,000 per megawatt
23 month. Using this as a proxy for what would have
24 been purchased in 2001 translates to a cost for the
25 16.9 megawatts of \$270,000. That would be 16.9

1 megawatts times \$4,000 times 4 months. This is the
2 minimum amount that the Commission should include
3 to recognize the cost of the actual capacity used
4 in 2001 to meet the needs of Montana-Dakota's
5 retail customers.

6 Q. Would you please explain your concerns
7 regarding pension expense?

8 A. Yes. Mr. Diller denied Montana-Dakota's
9 increase in pension expense for two reasons.
10 First, because there was no actuarial data provided
11 in the discovery process and, second, because
12 overall benefits expense decreased by \$43,000 from
13 2000 to 2001. I will address both of those
14 concerns.

15 When Montana-Dakota was preparing its
16 direct testimony, we looked at current or 2002 cost
17 levels versus the cost levels for 2000 as included
18 in Mr. Diller's cost of service. Where the 2002
19 cost level was different from the 2000 level we
20 reviewed the cost to determine the appropriate
21 expense given current information.

22 The benefits account, that is FERC account
23 926 labeled employee benefits, includes pension,
24 medical and dental insurance, post-retirement,
25 401(k), employee discounts and other benefits. The

1 pension account was the only benefit that
2 significantly changed from 2000 to current or 2002
3 levels, so that was the only benefit that was
4 adjusted in my direct testimony.

5 The primary reason for the slight decrease
6 in benefit expense from 2000 to 2001 is because the
7 pension and post-retirement amounts were less in
8 2001 than 2000. But that situation has turned
9 around and those expenses increased and are
10 currently higher than the 2001 level.

11 Montana-Dakota externally funds the
12 pension and post-retirement accounts with the
13 annual expense based on an actuarial study
14 performed by Towers Perrin. I should note that the
15 actuarial study is considered confidential
16 information and as such cannot be provided as a
17 public document. Montana-Dakota, as it has done
18 with such information in the past, will agree to
19 let Mr. Diller review that information on a
20 confidential basis.

21 As explained in my direct testimony, the
22 reason for the increase is because of low
23 investment returns in 2000 and 2001 and a lower
24 discount rate for future years than in the previous
25 studies. These increases for 2002 are real,

1 they're currently being booked, and they are
2 expected to continue to increase through 2006.

3 To deny recovery of current expenses
4 because the expenses decreased between 2000 and
5 2001 when current expense levels are demonstrably
6 higher is not reasonable. Exhibit DRB-1 shows the
7 2001 level of expense and the current expense
8 levels that Montana-Dakota is recording on its
9 books for pension and post-retirement benefits.
10 The amount of the adjustment for pension is
11 \$179,000, and the adjustment for post-retirement
12 benefits is \$62,000.

13 I should note that the amount for the
14 supplemental income security plan discussed in the
15 surrebuttal testimony of Mr. Espeland is \$683,000
16 currently. This reflects an update from the amount
17 contained in my direct testimony.

18 Q. Would you please explain your concerns
19 with the insurance expenses?

20 A. Yes. Mr. Diller proposes to leave
21 insurance expense at the 2001 levels because the
22 2001 level of expense changed very little from
23 2000. He also says that he needs additional proof
24 from Montana-Dakota that insurance expenses have
25 increased. Most of Montana-Dakota's insurance

1 policies expire in November or December of each
2 year. Therefore, the significant increases in
3 insurance expense as outlined in my direct
4 testimony became effective in late 2001 and
5 therefore are not visible when comparing 2001
6 expense to 2000 expense.

7 However, the level of expense that we are
8 incurring today is significantly higher than we
9 experienced in 2001. The increase in insurance
10 costs is affecting companies nationwide, not just
11 Montana-Dakota.

12 I have been advised by the company's risk
13 management personnel that the year 2000 and
14 beginning of 2001 were reflective of soft market
15 conditions, that is, expanded coverage at lower
16 prices, and the insurance costs for these years
17 reflect that market.

18 The situation changed in 2001 when the
19 market changed to hard market conditions reflective
20 of lower coverage and higher prices. The September
21 11, 2001, terrorist attack further exacerbated the
22 situation by increasing costs and changing
23 available policy coverages.

24 One example of the change is the All Risk
25 Property Insurance premium, which went from an

1 annual premium of approximately \$377,000 in effect
2 through December 2001 to an annual premium of
3 \$550,600 through December 2002, an increase of 46
4 percent. These increases are real and the higher
5 premiums are in effect today.

6 Exhibit DRB-2 lists each of the insurance
7 policies along with the expiration date of the
8 policy and the current annual expense. As shown on
9 the exhibit, the annual expense being incurred
10 today is 37 percent higher than the 2001 level for
11 insurance. Montana-Dakota's proposed insurance
12 expense adjustment of \$155,000 reflects the level
13 being incurred today and is reasonable.

14 Q. Would you please explain your concerns
15 with Mr. Diller's adjustment to office supplies and
16 expense?

17 A. Yes. At pages 18 and 19 of his rebuttal
18 testimony Mr. Diller discusses his adjustment to
19 office supplies and expenses. His adjustment
20 reflects a five percent increase over the 2000
21 level with a net result of decreasing the actual
22 2001 result by \$678,000. His testimony indicates
23 that he is not aware of what caused the increase
24 and that he made the adjustment to reflect a more
25 normal operating expense level.

1 I take exception to this adjustment
2 because the items that caused the increase from
3 2000 to 2001 are not one-time aberrations but are
4 continuing expenses. Items causing the increase
5 from 2000 to 2001 are the costs for a corporate
6 aircraft, which was acquired in 2001, increased
7 service and supply costs for the company's computer
8 infrastructure, an increase in phone expenses due
9 to expanding cell phone use, and improvement of the
10 computer frame relay network, an increase in
11 subcontract work which is continuing, and
12 reclassification of subcontract fees and bank
13 service fees from other accounts. The last item
14 simply means that other accounts were reduced to
15 reflect the reclassification.

16 As these are recurring expenses, the
17 amounts should be included which reflects an
18 increase in expense of \$678,000 from the staff
19 position.

20 Q. Mr. Ball, in connection with your
21 responsibilities with the company, are you familiar
22 with how the capital structure is computed and the
23 debts are carried on the books?

24 A. Generally I am, yes.

25 Q. There may be some confusion in the record,

1 I think, regarding the term loan that was testified
2 to earlier this morning. Could you explain that
3 and your understanding of how that was booked?

4 A. The term loan was discussed by Mr.
5 Mahowald in his testimony, and as he explained, the
6 company periodically will exercise that term loan
7 to draw down its short-term debt to demonstrate to
8 rating agencies and to the financial world that the
9 company does have the financial ability to pay down
10 its short-term debt.

11 Typically, the term loan is exercised at
12 the end of quarters and typically for a very short
13 duration. In this proceeding I believe we were
14 asked to provide what the company's capital
15 structure was, and I believe we have provided that
16 in a number of places, primarily even in the annual
17 report to the Commission. It's a balance sheet
18 item, and the numbers there reflect the balances
19 that were in existence for the time -- for the day
20 indicated, typically balances as of December 31 of
21 each year. So -- so the reports in that respect
22 reflect the books and records of the company at
23 that point in time, as it does with any other
24 balance sheet item.

25 In this proceeding staff witness, Mr.

1 King, looked at that item. He took exception to
2 including 40,000 -- or 40 million dollars in the
3 capital structure. Instead, he looked at the
4 average balance of that particular item that would
5 be outstanding, and that is what he reflected in
6 his capital structure. For purposes of this
7 proceeding we are not contesting the use of the
8 average balance of the term loan in the capital
9 structure. The average balance, I believe, was 1.3
10 million.

11 Q. And it was testified, of course, that MDU,
12 as every major company does, has its books and
13 records audited by every year. Are you aware that
14 the company has made a public announcement already
15 that it's going to be changing its auditors?

16 A. Yes, I am aware of that.

17 Q. So it will no longer be Arthur Andersen?

18 A. That is correct.

19 Q. And I'm not suggesting that's a result --
20 you don't know of anything wrong that Arthur
21 Andersen did, but it's customary, is it not, from
22 time to time to periodically review and perhaps
23 change auditors?

24 A. Yes, that is correct.

25 MR. PEARCE: I have nothing further for

1 Mr. Ball.

2 MR. HOBERG: Thank you, Mr. Pearce. Mr.
3 Binek, did you have any questions of Mr. Ball?

4 MR. BINEK: Yes.

5 CROSS-EXAMINATION

6 BY MR. BINEK:

7 Q. Getting back to this 40-million-dollar
8 debt item, if -- if a staff witness had not reduced
9 that item, would the overall debt in the capital
10 structure have reflected something in the
11 neighborhood of \$40,000 above what it is now --
12 today, that you've agreed to -- or 40 million, I
13 mean.

14 A. You mean 40 million? Yes. As a matter of
15 fact, if you go back in history to rate cases that
16 this company has had in the four-state area that it
17 serves, it was a very common practice to include
18 that, the entire 40 million in the capital
19 structure in determining the ratios.

20 Q. This supplemental income security plan,
21 are you one of the key employees?

22 A. Yes.

23 Q. Do you plan to leave the company if the
24 benefit is discontinued?

25 A. I guess I haven't really considered it.

1 Q. On the expense items, this corporate
2 aircraft, what benefit does Montana-Dakota
3 Utilities Company in its North Dakota operations
4 derive from the corporate airplane?

5 A. Well, I think there are a number of
6 benefits. The company, you know, has a number of
7 employees that to conduct their business are
8 required to travel, and in the -- in using a
9 corporate aircraft before any trip is made, you
10 have to request to use the aircraft. If -- and we
11 have a travel coordinator, and if it does not
12 appear to be cost-effective to use the corporate
13 aircraft, we will use other means of travel, such
14 as commercial aircraft or drive.

15 Q. Has there been any study done to quantify
16 the savings that the company realizes through the
17 use of this corporate aircraft?

18 A. I believe there was one --

19 Q. I'm talking about the North Dakota --
20 Montana-Dakota Utilities Company in North Dakota.

21 A. Not to my knowledge.

22 Q. What is the percentage increase in
23 expenses from the year 2000 to 2001, administrative
24 and general expenses?

25 A. Percentage increase?

1 Q. Right.

2 A. Oh, you mean for the administrative and
3 general --

4 Q. Expenses.

5 A. -- expense category?

6 Q. Right.

7 A. All accounts? I guess I don't have that
8 information in front of me.

9 Q. Okay. Do you recall Mr. Diller's slide
10 show where he had that up?

11 A. Yes. Yes, I do.

12 Q. Okay. Can --

13 A. Well, however, my copy is the reduced
14 slides, and the numbers are very small. I can't
15 read them.

16 MR. HOBERG: Could you provide him a copy
17 of that, please?

18 MR. DILLER: Yes. It's slide 23, but
19 Bill and I only have the numbered pages.

20 MR. HOBERG: What's it titled at the top?

21 MR. DILLER: Administrative and general.

22 MR. HOBERG: Thank you.

23 MR. BINEK: Administrative and general
24 expenses.

25 THE WITNESS: And your question again was

1 what was the --

2 Q. (MR. BINEK CONTINUING) Percentage
3 increase from 2000 to 2001.

4 A. According to Mr. Diller's slide, it's 12.4
5 percent.

6 Q. And the increase projected from 2001 to
7 2002?

8 A. According to Mr. Diller's slide, it's 12.3
9 percent.

10 Q. And do you have any reason to disagree
11 with the figures on Mr. Diller's slide?

12 A. No, I don't.

13 Q. Prior to 2001 and 2002 what -- what range
14 were increases?

15 A. Again, from Mr. Diller's slide, the '98 to
16 '99 was a decrease of 3.4 percent, '99 to 2000 was
17 a decrease of 3.8 percent.

18 Q. Are you going to respond with any
19 analysis -- any additional analysis to Mr. Diller's
20 concern regarding the adjustments you've proposed
21 for office supplies expense, property insurance and
22 employee pensions and benefits?

23 A. Yes, I was. Mr. Pearce was going to ask
24 me a question about that.

25 Q. Oh, I thought he was done.

1 While the expense levels seemed quite inflated in
2 comparison to recent years, staff agreed in
3 principle with the company's 2002 overall labor
4 expense projection," which is in another paragraph,
5 I believe. "Therefore, staff proposes no
6 adjustment to these inflated expense accounts, as
7 they are primarily labor related."

8 Would that explain why your pension costs
9 went up if your administrative and general salaries
10 increased by 20 percent? Are your pension costs
11 related to your salary levels?

12 A. Pension costs are related to salary
13 levels, but I don't think we can make the
14 conclusion that the changes that we see in these
15 two particular accounts for labor expense would
16 drive up the pension costs because pensions are
17 based on total.

18 Q. Well, if I had a salary at your firm of --
19 if I received a 20 percent salary increase in 2001
20 from MDU Utilities, wouldn't I expect to see an
21 increase in my pension?

22 A. Yes, you would.

23 Q. So could that partially explain the
24 dramatic increase in the pension dollars that were
25 shown?

1 A. Well, actually I would not categorize the
2 pension increase as dramatic. On an overall basis
3 the average pay increases have been in the three to
4 three-and-a-half percent range.

5 Q. Well, then how did they get to be 20
6 percent?

7 A. That's just one particular account.

8 Q. Well, it's all administrative and general
9 salaries.

10 A. Well, that would simply be the
11 administrative and general salary category.

12 Q. Right.

13 A. There are a number of employees whose
14 labor is charged to other accounts.

15 Q. I understand that, and that's why labor is
16 in another paragraph that he's referring to.

17 A. Right.

18 Q. But I was just referring to this group of
19 employees.

20 A. Yeah. To this -- those employees whose
21 time is charged to this particular account, we did
22 see an increase of this magnitude in the dollars
23 booked in that account from 2000 to 2001.

24 Q. About how many employees are in that
25 category?

1 agencies which hopefully would result in lower
2 interest rates down the line that you would have to
3 pay. So I guess I understand it from that, but
4 what you're saying is from a regulatory standpoint
5 the -- the way that Mr. King has -- for dealing
6 with this, it's not contested, it's kind of okay,
7 that average balance method that he's offered is
8 all right. Is that MDU's position?

9 A. Yes. In a nutshell, that's it.

10 Q. Okay. Now just to do a quick followup on
11 the -- something which wasn't brought up by staff
12 but kind of piqued my interest on the break that
13 current and former employees -- or retired
14 employees get on utility bills. Is -- it sounds
15 like that's something that -- it's just -- it's
16 reflected in a decreased net income; is that right?

17 A. You're referring to the utility discount?

18 Q. Yeah.

19 A. Actually, that has been in place for a
20 number of years. There's actually a tariff on file
21 here at the Commission specifying what that is.

22 Q. Okay.

23 A. And our employees who actually take gas
24 and/or electric service from us simply get
25 one-third off of their bill.

1 Q. Okay.

2 A. Now --

3 Q. So the cost is fully recovered of
4 providing the service; is that right?

5 A. Yeah. The cost -- at least the
6 incremental cost is fully recovered. For -- and
7 the discount applies to MDU Resources employees, as
8 well. It also applies to Knife River Corporation
9 employees or Williston Basin Interstate Pipeline
10 Company employees. For all employees of companies
11 other than Montana-Dakota, those other companies
12 reimburse us in full for the amount of those
13 employee discounts. So from that perspective our
14 consumers are not paying, if you will, or there's
15 nothing in the costs for those discounts for
16 employees of the other companies. For
17 Montana-Dakota employees and the allocated portion
18 of the Resources employees there is no specific
19 reimbursement, and the amount of the utility
20 discount would be a cost-of-service item.

21 Q. Okay. Do you have any idea what that cost
22 is in dollar figures?

23 A. I guess I don't specific to North Dakota,
24 but I do know that in -- the utility discounts for
25 2001 were about \$290,000 companywide.

1 Q. Just from a -- kind of justification
2 standpoint, what is the rationale for that?

3 A. For the discount?

4 Q. Yeah.

5 A. The rationale for the discount is that
6 it's part of compensation, and one way to look at
7 that would be it's -- if you will, it's a tax-
8 exempt compensation. So, in other words, if we
9 were to make it equivalent in actual pay, on a net
10 basis we would have to raise salaries by more than
11 the amount of the discounts because people would
12 have to pay taxes on that if it's part of their
13 payroll. So this happens to be the least costly
14 way to do it.

15 COMMISSIONER CLARK: Okay. That's all the
16 questions I have. Thank you.

17 THE WITNESS: Thank you.

18 MR. HOBERG: Thank you, Commissioner
19 Clark. Mr. Pearce, anything further then of this
20 witness?

21 MR. PEARCE: Just one -- well, perhaps
22 two.

23 REDIRECT EXAMINATION

24 BY MR. PEARCE:

25 Q. Getting back to the question of the

1 corporate aircraft, is there any kind of -- is
2 there an employee or department -- sort of a
3 centralized department that keeps track of the
4 aircraft use and decides whether it's economic or
5 not?

6 A. Yes, there is, and that's done on a trip-
7 by-trip basis.

8 Q. So, for example, I suppose you wouldn't
9 send one employee to a meeting in Washington or New
10 York on the company plane?

11 A. We would not.

12 Q. Because that would not be economical?

13 A. That would not be cost-effective.

14 Q. But you might send four or five because
15 that would be less than the total airfare
16 commercially?

17 A. Yes, that's true, and you also consider
18 the factor of the other -- you know, the other
19 costs related to alternative means. You know, for
20 example, many times you won't have to stay
21 overnight, you can avoid meal costs, accommodation
22 costs.

23 Q. Right.

24 A. Those are factored in as well.

25 Q. And it's simply a matter of the time of

1 the employees, I suppose --

2 A. Yes.

3 Q. -- to be most economically used.

4 A. That is true.

5 Q. Okay. Is there anything else I've failed
6 to ask that you'd like to respond to?

7 A. Yes. In Mr. Diller's slide show yesterday
8 he talked about three areas where he remained
9 unconvinced of what was going on, and I would like
10 to take a few minutes just to hopefully shed some
11 more light on those particular areas.

12 I'd like to start with pension and
13 post-retirement benefits expense. As I indicated
14 in my surrebuttal testimony, pension and
15 post-retirement benefits are included in the FERC
16 account number 926 along with several other items.
17 I think I mentioned medical and dental, 401(k),
18 utility discounts are in that particular account,
19 those types of things.

20 In our analysis of that we can compare the
21 results, and what we saw from 2000 to 2001 would be
22 a slight decrease in the pension and benefits area,
23 and I would note that all of the changes in that
24 account are caused by the pension and post-
25 retirement benefit areas. There were some minor

1 changes to the other accounts or other items in
2 there, some are up, some are down, but they're all
3 typically under the \$10,000 range of change, either
4 up or down.

5 With pensions and the post-retirement
6 benefits the company uses an actuary. The firm's
7 name is Towers Perrin, and they provide periodic
8 actuarial studies as to what the funding
9 requirements are to meet the pension obligation and
10 the post-retirement benefit obligation that the
11 company has.

12 The latest study from Towers Perrin
13 indicated that there would be increases in both of
14 those categories, and the study really relates to
15 the period beginning now, with 2002. So for 2001
16 we were operating under the prior study. The new
17 study clearly indicates an increase that is
18 necessary in the amounts that the company will need
19 to accrue to cover these costs.

20 We began recording the higher costs on our
21 books in January of 2002. So primarily you will
22 not see any increase on our books in 2001 because
23 we didn't start doing it until almost two months
24 ago now.

25 In reviewing the results of the actuarial

1 study, we know what we need to accrue for pensions
2 and post-retirement benefits. We began doing that,
3 and the numbers that I have provided to you for the
4 electric utility and then as allocated to North
5 Dakota electric operations reflect the amounts that
6 we are now accruing on our books, and very simply
7 we took the January accrual times 12 because that
8 is what the actuarial study indicates that we need
9 to do.

10 I would note that in spite of the fact
11 that there is an increase in the pension expense,
12 that the grand total pension expense is still a
13 negative number. In other words, the plan has
14 adequate funding and we can have a negative
15 expense, if you will, which simply reduces our
16 overall costs. However, when you go from a bigger
17 negative to a smaller negative, that's a bigger
18 increase. On post-retirement it's the other way.
19 It is a positive number that we need to accrue, and
20 that is what we're doing. On a net basis the
21 difference is very small when you get down to it.

22 I guess I would offer that additional
23 information on pensions. It is based on an
24 actuarial study. As I indicated in my testimony,
25 the actuarial study is confidential in nature.

1 However, if Mr. Diller would like to review it on a
2 confidential basis, he's certainly welcome to do
3 so, and quite frankly, there was only one week
4 between the submission of our surrebuttal testimony
5 and the beginning of our hearing. So there was
6 relatively little time to deal with that matter as
7 we typically have done in the past.

8 With regard to insurance expense, some
9 additional comments there. Insurance expense
10 covers primarily property insurance and then the
11 other miscellaneous areas, you know, related
12 injuries and damages. The amounts are recorded in
13 FERC account 925 for property insurance -- I'm
14 sorry, 924 for property insurance and 925 for
15 injuries and damages.

16 In looking at the actual results for 2001,
17 and I will refer you to my Exhibit DRB-2, which is
18 attached to my surrebuttal testimony, our actual
19 expense for North Dakota electric operations was
20 \$420,193, and before I go further, let me make one
21 minor correction to the exhibit in the first column
22 labeled "type of insurance." The third item from
23 the bottom says aircraft coverage. Strike that and
24 insert the word "subtotal."

25 MR. HOBERG: Did everyone get that? Okay.

1 THE WITNESS: As you'll note, the bulk of
2 our insurance policies have expiration dates of
3 around -- like October 31 there's a whole group
4 there. We have another group where the policies
5 expire at the end of the year, and those are
6 renewed annually, and what we now have is that you
7 will not see again increased expenses there for the
8 year 2001 because the new costs have just taken
9 over and we're just now incurring those new costs
10 beginning either like November 1 or January 1,
11 depending upon the expiration of the policies.

12 So just looking at the activity for
13 insurance in 2001 really won't show you what the --
14 what the real picture is with respect to those
15 costs. The annual premium that I've listed here is
16 the current premium. You begin booking those costs
17 the day that the new premium took over, and it's
18 fairly clear that there is a substantial increase
19 in insurance costs. We're booking those costs
20 today, and we believe that it would be appropriate
21 to include those cost levels in your determinations
22 here because those are the costs that we are now
23 incurring.

24 The last area was office supplies
25 expenses. In -- and I guess I explained in my

1 surrebuttal what Mr. Diller did. He saw a fairly
2 substantial increase in the office supply expense
3 account, and in looking at that I looked at the
4 items that made up that change, and they're not
5 just one-time things.

6 For example, we already talked briefly
7 about a corporate aircraft. This was an aircraft
8 acquired in January 2001. You've never seen those
9 costs for that aircraft in that account before.
10 That's about \$226,000 worth of change. There was
11 also a reclassification of certain costs that used
12 to be included in account 930. Those relate
13 primarily to annual report preparation, annual
14 report printing, interim report printing, items
15 like that. That was simply moved from the 930
16 account and placed in the 921 account, and you can
17 clearly see that there's a reduction in the 930
18 account for that.

19 There was also a reclassification of bank
20 service fees. I believe those were primarily
21 related to transfer agent fees for stock
22 transactions, items like that. It's just that they
23 had been booked in account 930 in the past. It was
24 believed that they would be more appropriately
25 accounted for in account 921, which is defined as

1 office supplies and expenses.

2 There were also some changes in account
3 921, the office supplies accounts, that relate to
4 an increase in costs related to the ongoing use and
5 maintenance of personal computers. We're using a
6 lot more on-line capability today than we used to.
7 There's added telephone fees, there's added fees
8 for relays in there, and those, in my opinion, are
9 ongoing costs and should be included here, and with
10 that --

11 MR. HOBERG: Mr. Pearce, anything further
12 questions?

13 MR. PEARCE: I have nothing else.

14 MR. HOBERG: Thank you. Mr. Binek, any
15 further questions of Mr. Ball?

16 MR. BINEK: Yes. We will have some. Can
17 we just take a couple minutes?

18 MR. HOBERG: Sure. Let's just take five
19 minutes, just strictly five minutes.

20 (Recess taken.)

21 MR. HOBERG: We're back from a short
22 recess, and, Mr. Binek, you had a few more
23 questions of Mr. Ball?

24 MR. BINEK: Yes.

25

1 RECCROSS-EXAMINATION

2 BY MR. BINEK:

3 Q. Mr. Ball, do you have a schedule to
4 support what you've testified to here --

5 A. I can provide you --

6 Q. -- concerning pension, post-retirement
7 benefits, insurance expenses that would show the
8 2001 expense as well as your 2002 expenses and the
9 changes that you talked about with the office
10 supplies?

11 A. I can provide that information as a late-
12 filed exhibit.

13 MR. HOBERG: Did you want a late-filed
14 exhibit?

15 MR. BINEK: Yes.

16 MR. HOBERG: Specifically what was that
17 again?

18 MR. BINEK: Well, maybe Mr. Diller can ask
19 specifically what it is he feels the Commission
20 needs.

21 MR. HOBERG: Okay.

22 MR. DILLER: That will eliminate some of
23 the talking back and forth. I think Don has a very
24 good schedule here laying out miscellaneous general
25 expenses, has every account, the 2001 costs, 2000.

1 The titles do need to be filled in for all of
2 those.

3 THE WITNESS: Yes.

4 MR. DILLER: I think that would be a
5 small thing to ask. Then the Commission can go
6 through there and make its own mind up as to
7 whether it wants to grant increases in the various
8 accounts. That one, I think, would be very
9 helpful.

10 And then on the pension and
11 post-retirement benefits I understand that none of
12 the other 926 costs -- the company won't have any
13 knowledge of what 2002 costs will be for those
14 other expenses within that account, and so I'm okay
15 with what they've recommended here with Towers &
16 Perrin. It's an actual cost. I don't need to see
17 the Towers & Perrin -- is that the right name?

18 THE WITNESS: Yes.

19 MR. DILLER: -- report, and so to me that
20 one we don't need any information on, but the
21 office supplies, and the last one is insurance
22 expense, and I think this one will be a real easy
23 one for the company to provide, as well, and make a
24 lot of sense to the Commissioners. You have 2002
25 annual premiums on your DRB-2. It would be a

1 simple matter to put in 2001 annual premiums and
2 then total those up, just like you've done for
3 2002. The difference times North Dakota factor is
4 the answer for insurance expense adjustment. I
5 don't know what that 420,193 is on DRB-2, but then
6 the Commission can see exactly which premiums went
7 up, which ones didn't. It's a mathematical
8 calculation from there.

9 COMMISSIONER WEFALD: Are you telling us
10 that you're agreeing with the 3,883,000 for the MDU
11 employee benefits? Are you agreeing with their
12 number? Is that what you just said?

13 MR. DILLER: Based on what I've heard Don
14 explain -- based on his explanation I understand --
15 I understand what they've done, and you can decide
16 based on what they've -- I'm just saying that I
17 don't need any more information on that.

18 COMMISSIONER WEFALD: All right. Thank
19 you.

20 MR. DILLER: You can decide for yourself.

21 MR. HOBERG: Mr. Diller, on the office
22 supplies one, was that DRB-2 -- or 1? I'm sorry.

23 MR. DILLER: It's DRB-2 on the insurance
24 expense.

25 MR. HOBERG: Insurance, yeah, but what was

1 the office supply one?

2 MR. DILLER: That's just a schedule that
3 Mr. Ball's been talking from the last five or ten
4 minutes.

5 MR. HOBERG: Is that designated something
6 DRB or --

7 THE WITNESS: There was no exhibit on
8 that.

9 MR. HOBERG: Okay.

10 MR. DILLER: It's to be provided later.

11 MR. HOBERG: Okay.

12 MR. BINEK: I guess I do have -- I have a
13 question.

14 MR. HOBERG: Just a minute, Mr. Binek. So
15 we have two late-filed exhibits then, one on office
16 supplies and one on insurance expense?

17 MR. DILLER: Right.

18 MR. HOBERG: Okay. So that would be late-
19 filed Exhibit 17 and then 18. Is that
20 satisfactory, Mr. Pearce?

21 MR. PEARCE: Yes.

22 MR. HOBERG: Okay. Thank you. Mr. Binek,
23 please.

24 MR. BINEK: Yes. I just have a couple
25 questions on the expenses related to the airplane.

1 Q. (MR. BINEK CONTINUING) How are the costs
2 of the airplane determined for Montana-Dakota
3 Utilities?

4 A. The corporate aircraft that was acquired
5 in January of 2001 is owned by someone other than
6 Montana-Dakota, and the costs that we're looking at
7 represent Montana-Dakota's allocated share of the
8 fixed costs of that airplane.

9 Q. Okay. And how is that share determined?
10 Is it just a percentage -- a percentage of the cost
11 of the airplane that's applied to Montana-Dakota
12 Utilities, or is it based on the use that
13 Montana-Dakota Utilities makes of the plane -- or I
14 guess that's what I'm getting to. How do you
15 determine what costs Montana-Dakota Utilities
16 should cover?

17 A. The fixed costs will be allocated among
18 the various companies based on a standard corporate
19 overhead allocation process.

20 Q. So for the fixed cost of the airplane like
21 depreciation?

22 A. Depreciation, maintenance, the capital
23 cost.

24 Q. Okay. Doesn't matter how much -- how much
25 use Montana-Dakota Utilities has of the airplane or

1 makes of the airplane. It's going to get a set
2 amount -- it's going to get a percentage charge of
3 the depreciation, maintenance and all of that
4 irregardless of the use it makes of the plane?

5 A. That is correct. Now the actual use of
6 the airplane is billed out on an hourly basis,
7 based upon who actually uses the aircraft.

8 Q. What is Montana-Dakota Utilities' share of
9 the fixed costs of the airplane?

10 A. I guess I don't know right off the top of
11 my head.

12 Q. Could you provide that information, also?

13 A. Sure.

14 MR. HOBERG: Okay. Can we make that late-
15 filed Exhibit 19 then?

16 Q. (MR. BINEK CONTINUING) Do you know --
17 excuse me. Do you know how much Montana-Dakota
18 Utilities uses the airplane or can you provide that
19 information?

20 A. I would have to provide it because I do
21 not know.

22 Q. Okay. Would you also please provide that
23 as a late-filed exhibit?

24 MR. HOBERG: Make that a part of 19,
25 please.

1 Q. (MR. BINEK CONTINUING) And would you also
2 show what the percentage use for Montana-Dakota
3 Utilities is as compared to the other participants?
4 Can you make that comparison, like does
5 Montana-Dakota Utilities utilize the airplane ten
6 percent of the time or --

7 A. And others 90 percent?

8 Q. Yeah.

9 A. Yeah. I think by definition if I say we
10 use it 10 percent of the time, somebody else uses
11 it 90 percent of the time.

12 Q. Well, can you break it out as to -- do you
13 want it for each one?

14 MR. LEIN: You'd like take the number of
15 hours it was in the air and how many of those were
16 MDU's and how many of them belonged to somebody
17 else.

18 THE WITNESS: If I just based it on hours'
19 use, would that suffice?

20 MR. BINEK: Yes.

21 MR. HOBERG: Make that a part of 19 also,
22 please.

23 MR. BINEK: Nothing further.

24 MR. HOBERG: Nothing further? Thank you,
25 Mr. Binek. Mr. Fahn, anything further?

1 MR. FAHN: No thanks.

2 MR. HOBERG: Nothing? Any further
3 Commission questions?

4 COMMISSIONER WEFALD: I do.

5 MR. HOBERG: Commissioner Wefald, please.

6 FURTHER EXAMINATION

7 BY COMMISSIONER WEFALD:

8 Q. I'm confused with some numbers here and
9 maybe you can help me.

10 A. We hope so.

11 Q. Under the employee benefits -- pensions
12 and benefits, on Mr. Diller's chart that's included
13 in Exhibit 3 entitled administrative and general
14 expenses.

15 MR. HOBERG: Do you still have that, Mr.
16 Ball?

17 Q. (COMMISSIONER WEFALD CONTINUING) Is that
18 the small copy?

19 A. I have the small version.

20 Q. I'm looking at the last two columns.

21 MR. HOBERG: Just a minute. He's getting
22 it from Mr. Diller.

23 MR. DILLER: That's a little bigger, but
24 not much.

25 Q. (COMMISSIONER WEFALD CONTINUING) I'm

1 looking at -- the number under 2001 is \$2,415,000.

2 Do you see that number?

3 A. Yes.

4 Q. And then I'm seeing the MDU number, which
5 is \$3,883,000?

6 A. Yes.

7 Q. All right. Now, you maybe can't comment
8 on this, but "Mr. Ball argues for a small increase
9 in pension costs of 116,000 for North Dakota
10 operations based on information received from its
11 actuary," and that's on page 15 of Mr. Diller's
12 testimony?

13 A. Okay.

14 Q. What is he referring to there when he
15 talks about the small increase in pension costs of
16 116,000 when this number to me looks like it's 1.4
17 million dollars difference in employee pensions and
18 benefits? What am I missing here?

19 A. I know part of it would be the costs
20 related to SISP.

21 Q. Okay.

22 A. About 680,000.

23 Q. But that cost has been defined in another
24 paragraph?

25 A. That would be about \$680,000.

1 Q. \$680,000. So then what's the other 1.4
2 million? What's the other part of it?

3 A. What he's looking at is the 2,415,000 --

4 Q. Yes.

5 A. -- for 2001. He's included a 285,000
6 pension adjustment, \$99,000 post-retirement benefit
7 adjustment, and 1,084,000 for SISP, and another
8 thing -- I believe these are total company numbers,
9 not just North Dakota numbers.

10 Q. The administrative and general expense
11 numbers are total company numbers?

12 A. Yes. And the million-84, for example,
13 that he included I believe he extrapolated the
14 \$680,000 North Dakota number upward to a total
15 company number.

16 Q. All right. Okay. That helps me
17 understand that. Thank you. And then on your
18 salaries line item where there was the jump -- I
19 need that same chart.

20 A. Okay.

21 Q. On the salaries line item where it went
22 from 4,181,000 in year 2000 to 5,024,000 in 2001,
23 those are again total company numbers?

24 A. Yes, they are.

25 Q. When were those -- what month were those

1 salary adjustments given?

2 A. The salary adjustments typically occur at
3 the first of the year, January 1.

4 Q. Did they occur last January 1 --

5 A. Yes.

6 Q. -- of 2001?

7 A. Yes. And January 1 of 2000.

8 Q. And January 1 of 2000?

9 A. Correct.

10 COMMISSIONER WEFALD: All right. Thank
11 you.

12 MR. HOBERG: Thank you, Commissioner
13 Wefald. Commissioner Clark, anything further.

14 COMMISSIONER CLARK: I do. It's maybe
15 just a followup to Commissioner Wefald.

16 EXAMINATION

17 BY COMMISSIONER CLARK:

18 Q. The jump between 2000, 2001 on that salary
19 line item, I noticed in your direct testimony you
20 had mentioned 4.32 percent increase January 1,
21 2001, and there must have been one on January 1,
22 2000, as well, and then there's a three-and-a-half
23 percent on '02, which all certainly seem very
24 reasonable, but I'm wondering then why the -- looks
25 like about 20 percent increase in that one year,

1 from 2000 to 2001, whereas most of the others on
2 Mr. Diller's spreadsheet seem to be percentagewise
3 much less. Was there some reason behind that that
4 drove that particular year?

5 A. The overall -- you know, the percentage
6 increases that you quoted would represent the
7 percent change in overall labor costs, but from --
8 from year to year we do see differences in the
9 amount of labor that is booked in, for example,
10 operation and maintenance expense accounts versus
11 capitalized as part of capital projects. So it's
12 difficult to see a direct relationship between the
13 overall percent and then the amount that might go
14 to any particular account.

15 Q. Okay.

16 A. And I guess that's -- a long way of saying
17 that is I don't know how to explain that difference
18 adequately at this point.

19 Q. And the salary line item would be kind of
20 inclusive of all those types of things, like maybe
21 you had some reason you needed to hire a lot of
22 temporary employees for some project or something.
23 It could be any one of a number of things; right?

24 A. That is correct.

25 Q. Okay. And then this is just more kind of

1 out of curiosity. The regulatory commission line
2 that Mr. Diller has on his sheet there, what type
3 of things does that include?

4 A. That includes any expenses directly
5 related to matters, to docketed items before a
6 regulatory commission.

7 Q. It doesn't mean to imply that when
8 Commissioner Hagen left, he was costing MDU
9 158,000, does it?

10 A. No, not at all. And this would represent,
11 you know, four states, too.

12 Q. Okay. That does seem to be highly
13 variable, though, doesn't it?

14 A. Yes, it does.

15 COMMISSIONER CLARK: Thanks. That one's
16 just out of curiosity.

17 MR. HOBERG: Thank you, Commissioner
18 Clark. Anything further then of Mr. Ball?

19 Anything further? Thank you, Mr. Ball.

20 THE WITNESS: Thank you.

21 MR. PEARCE: Could we have about maybe two
22 minutes to confer briefly? I might be able to
23 clarify something else.

24 MR. HOBERG: Sure. Let's take a recess in
25 place here for a couple minutes.

1 (Recess taken.)

2 MR. PEARCE: Okay. We're back from a
3 short recess, and before -- well, we're maybe not
4 done with Mr. Ball yet.

5 MR. PEARCE: One final, final question, if
6 I may, Mr. Ball.

7 REDIRECT EXAMINATION

8 BY MR. PEARCE:

9 Q. Don, just before our little break here you
10 were responding to a question from Commissioner
11 Clark, and I think -- would you be willing to put
12 together some additional data filed as a late
13 exhibit to clarify the matter of what that increase
14 was that you were talking about?

15 A. Yes, I would. We were discussing the
16 approximate 20 percent change in the account 920,
17 administrative salaries, and I was not adequately
18 able to explain that. It's certainly not a 20
19 percent increase in salaries for our employees, but
20 I would -- I would offer to explain more fully why
21 the change occurred in that particular area.

22 MR. HOBERG: Okay. Late-filed Exhibit 20
23 then?

24 MR. PEARCE: No. 20, right.

25 MR. HOBERG: Okay.

1 MR. PEARCE: And that's all I have.

2 MR. HOBERG: Anything further then of Mr.
3 Ball?

4 MR. BINEK: No.

5 MR. HOBERG: Thank you, Mr. Ball. I'll
6 just note for the record that his direct testimony
7 is Exhibit 6, Docket No. 46, and surrebuttal,
8 Exhibit 7, Docket No. 57.

9 COMMISSIONER WEFALD: In that exhibit
10 would it be possible to put the dates that the
11 changes occurred?

12 THE WITNESS: Sure.

13 COMMISSIONER WEFALD: If it wasn't salary-
14 related, you know, like on July 1, if you could
15 indicate the dates when the other changes occurred.

16 THE WITNESS: Sure.

17 COMMISSIONER WEFALD: Thank you.

18 MR. HOBERG: Thank you, Mr. Ball. Mr.
19 Pearce, your last witness, I believe.

20 MR. PEARCE: Last witness will be Rita
21 Mulkern.

22 MR. HOBERG: Please be seated. Ms.
23 Mulkern, I think you heard the admonition I gave
24 earlier in regard to perjury; is that correct?

25 THE WITNESS: Yes, I did.

1 (Witness sworn.)

2 MR. HOBERG: Thank you. Mr. Pearce,
3 please.

4 RITA A. MULKERN,
5 having been first duly sworn, was examined and
6 testified as follows:

7 DIRECT EXAMINATION

8 BY MR. PEARCE:

9 Q. Would you please state your name and
10 business address?

11 A. My name is Rita A. Mulkern, and my
12 business address is 400 North Fourth Street,
13 Bismarck, North Dakota.

14 Q. And you're employed by Montana-Dakota
15 Utilities Company, are you not?

16 A. I'm employed by Montana-Dakota Utilities
17 Company as the regulatory analysis manager.

18 Q. And have you previously filed direct
19 testimony that's been made an exhibit in this
20 proceeding?

21 A. Yes, I have.

22 Q. What is the purpose of your testimony
23 today?

24 A. The purpose of my testimony is to quantify
25 the adjustments that -- to the North Dakota

1 Commission staff's rebuttal testimony that was
2 discussed earlier by the previous witnesses and the
3 effects of those adjustments on the North Dakota
4 electric revenue requirements. I am sponsoring
5 Exhibit -- and these were part of Exhibit 7 --
6 RAM-3 and Exhibit RAM-4, which quantify the effect
7 of these adjustments to the North Dakota electric
8 revenue requirement.

9 MR. HOBERG: Are those part of your
10 surrebuttal?

11 THE WITNESS: Yes, they are.

12 Q. (MR. PEARCE CONTINUING) Would you explain
13 the first sheet, RAM-3, please?

14 A. Yes. The exhibit summarizes the
15 adjustments to the income statement that were
16 supported by the other witnesses. Each of the
17 adjustments was developed either on a total company
18 basis and allocated to North Dakota or directly
19 assigned to North Dakota.

20 Q. And what does the next sheet, RAM-4, show?

21 A. RAM-4 is a summary showing the income
22 statement and rate of return for 2001, the staff
23 adjustments and the staff's position,
24 Montana-Dakota's adjustments from RAM-3, and then
25 the resulting income statement, rate of return and

1 revenue deficiency calculation. Page two shows the
2 same information for the rate base statement.

3 Q. Why does your exhibit show a staff revenue
4 excess of 7.135 million dollars rather than the
5 7.327 million dollars in Mr. Diller's rebuttal
6 testimony?

7 A. The difference is in the income taxes.
8 And the interest expense that's deductible for
9 calculating income taxes should have been restated
10 to reflect Mr. King's proposed debt costs. With
11 the lower debt cost, the interest deduction is
12 lower and results in higher income taxes. So the
13 income tax adjustment has been restated to reflect
14 the higher level of income taxes.

15 Q. What effect do the adjustments have on the
16 revenue requirement?

17 A. As shown on page one of RAM-4 under the
18 column labeled "adjusted," Montana-Dakota's
19 adjusted return on equity is 11.091 percent, which
20 is below the 12.75 percent return on equity
21 required. Montana-Dakota will experience a revenue
22 deficiency of \$1,727,000 at a 12.75 percent return
23 on equity based on the adjusted calendar year 2001
24 results.

25 Q. Does that complete your testimony?

1 A. Yes, it.

2 MR. PEARCE: I have nothing further.

3 MR. HOBERG: Thank you, Mr. Pearce. Mr.
4 Binek, did you have any questions of Ms. Mulkern?

5 MR. BINEK: Yes.

6 CROSS-EXAMINATION

7 BY MR. BINEK:

8 Q. The purpose of your testimony is to
9 quantify the adjustments that MDU has made and to
10 determine the revenue excess or revenue deficiency
11 based on all of Montana-Dakota Utilities'
12 calculations and using Montana-Dakota Utilities'
13 proposed return on equity?

14 A. That's correct.

15 Q. Okay. Are you one of MDU's key employees?

16 A. That depends on what -- how you define
17 "key employee."

18 Q. Well, we realize you're a key employee,
19 but for the purpose of answering my question are
20 you one of the key employees who receives this SISP
21 benefit?

22 A. I am not a part of the SISP program.

23 Q. Okay. So you fall into one of the lower-
24 income category employees?

25 A. I guess so.

1 A. The Pool sales number -- the total company
2 number that Mr. Blinsky came up with was -- and
3 this was based on the 6.4-million Pool number. We
4 compared that to the Pool number that was in Mr.
5 Diller's initial testimony and took the difference
6 between the 15.1, I believe, number Mr. Diller
7 had --

8 MR. DILLER: Pretty close.

9 THE WITNESS: -- and the 6.4 million and
10 took that times approximately 66 percent, which is
11 North Dakota's share of that total company amount,
12 and so basically what this 5.754 million dollars
13 difference is between the 6.4 million total company
14 Pool sales that we believe is the correct level and
15 the level that Mr. Diller had in his position.

16 Q. (COMMISSIONER WEFALD CONTINUING) So this
17 isn't the actual amount of Pool sales that were
18 received in 2001 from different sources?

19 A. That's correct.

20 Q. This is an adjustment that you're making
21 to show if this is used as the test year for -- to
22 determine future income needs you're making an
23 adjustment in that actual Pool sales number from
24 2001?

25 A. That's correct.

1 Q. Okay. All right. And then you're adding
2 \$1,670,000 of costs to the staff rebuttal case?

3 A. That's right. We're adding that much to
4 the expense side.

5 Q. All of these different adjustments that
6 Mr. Ball was just up discussing?

7 A. That's right.

8 Q. All right. I just wanted to make sure I
9 understand this particular document. Okay. And
10 then you're subtracting, though, an amount for
11 income taxes?

12 A. Yes. We're saying because we're going to
13 have less revenue and higher expenses, we're going
14 to pay less income taxes. So we're reducing the
15 income tax number.

16 Q. I see. Okay. And then -- so then your
17 net adjustment is \$4,346,000?

18 A. That's correct.

19 Q. And you're using those figures then on the
20 next page and substituting them in the appropriate
21 prices. All right. I'm fine.

22 A. Yes. That's right.

23 COMMISSIONER WEFALD: Thank you.

24 MR. HOBERG: Thank you, Commissioner

25 Wefald. Commissioner Clark, any questions of Ms.

1 Mulkern?

2 COMMISSIONER CLARK: I have none. Thank
3 you.

4 MR. HOBERG: Thank you. Anything further
5 then of Ms. Mulkern? No further questions? Thank
6 you, Ms. Mulkern.

7 MR. PEARCE: At this time I would offer
8 Exhibits 6 and 7, which are the two books
9 containing the original testimony and the
10 surrebuttal testimony of the MDU witnesses.

11 MR. HOBERG: Okay. Any objection?
12 Exhibits 6 and 7 are admitted.

13 (Off the record.)

14 MR. HOBERG: Okay. We're back on the
15 record. Commissioner Wefald, you had another
16 question of Ms. Mulkern?

17 COMMISSIONER WEFALD: I do.

18 Q. (COMMISSIONER WEFALD CONTINUING) Under
19 the -- under the sales for resale line -- page one
20 of two, exhibit -- it's actually under RAM-4 in the
21 surrebuttal testimony of MDU, that shows an
22 adjusted number of \$11,395,000 for sales for
23 resale; is that correct?

24 A. That's correct.

25 Q. That's the number that MDU is projecting

1 with adjustments?

2 A. That's right.

3 Q. Well, how is that -- how much different is
4 that from the number that Mr. Diller was proposing
5 for the three-year average?

6 A. Well, this -- the 11,395,000 first, it
7 represents the revenue received from the Pool
8 sales. In this exhibit the cost associated with
9 that Pool sales is in the fuel and purchase power
10 line. So you can't directly look at this and see
11 the same -- and see the Pool sales margin, which is
12 what Mr. Diller refers to using what Mr. Ball
13 referred to as the margin, the revenue less the
14 expense.

15 Q. All right. So where's your expense number
16 on this?

17 A. The expense for it is included in the fuel
18 and purchased power line, the first line under
19 operating expenses.

20 Q. The 31,762,000?

21 A. It's included in that number. It's not --

22 COMMISSIONER WEFALD: Okay. All right.

23 Thank you. I understand now. Thank you.

24 MR. HOBERG: Thank you, Commissioner

25 Wefald. Anything further then of Ms. Mulkern?

1 Thank you, Ms. Mulkern. Anything further of Ms.
2 Mulkern?

3 MR. PEARCE: No.

4 MR. HOBERG: Thank you. Okay. Mr.
5 Pearce, you've completed your presentation?

6 MR. PEARCE: Yes.

7 MR. HOBERG: Anything in rebuttal, Mr.
8 Binek?

9 MR. BINEK: No.

10 MR. HOBERG: Nothing in rebuttal? Okay.
11 Just a reminder then, we have Exhibits 1 through
12 20, of which 16, 17, 18, 19 and 20 will be late-
13 filed exhibits.

14 MR. PEARCE: Do we have a time frame?

15 MR. HOBERG: We're going to talk about
16 time frames in a minute here, but anything else to
17 bring to the attention of the Commission at this
18 time in regard to evidence outside of the late-
19 filed exhibits? Mr. Pearce?

20 MR. PEARCE: No. Just procedurally -- I
21 don't know if it's appropriate to do it yet, but at
22 this point since the evidence is all in, we'd
23 basically by way of motion renew our request to
24 dismiss the case on the grounds that the
25 Commission's case has not been proven by a

1 preponderance of the evidence.

2 MR. HOBERG: Thank you, Mr. Pearce.
3 Response, Mr. Binek?

4 MR. BINEK: We'll obviously resist that
5 motion. We feel we have set forth a sufficient
6 case for the Commission to consider.

7 MR. HOBERG: Okay. You don't have any
8 further evidence today, Mr. Binek?

9 MR. BINEK: No.

10 MR. HOBERG: Okay. Let's talk a little
11 bit about time frames then. I'm assuming the
12 Commission will want proposed findings of facts,
13 conclusions of law and order from each of the
14 parties, staff and MDU.

15 COMMISSIONER WEFALD: That would be
16 helpful.

17 COMMISSIONER CLARK: I'm sure Illona, if
18 she were here, would be shaking her head
19 vigorously. Yes.

20 COMMISSIONER WEFALD: And Pat.

21 COMMISSIONER CLARK: But Pat is.

22 MR. BINEK: Settle down back there.

23 MR. HOBERG: So I imagine you want the
24 late-filed exhibits before that. So can you have
25 those in what -- how long?

1 MR. PEARCE: Next Monday, a week.

2 MR. HOBERG: Okay. A week?

3 MR. PEARCE: Next Tuesday.

4 MR. HOBERG: One week.

5 MR. BINEK: I guess another question is
6 how long will it take for the transcript to be
7 prepared.

8 MR. HOBERG: Right. You want that before
9 the proposed findings.

10 THE REPORTER: Couple, three weeks.

11 MR. HOBERG: Three weeks. Okay. So the
12 late-filed exhibits will be filed with the
13 Commission a week from today. The transcript
14 should be ready in about two to three weeks.
15 Proposed findings, et cetera, what, two weeks after
16 the transcript? Is that enough time?

17 MR. BINEK: Let me see what's happening.

18 MR. PEARCE: That's fine for me.

19 COMMISSIONER WEFALD: I hope that'll be
20 okay. We want to keep the case moving along.

21 MR. BINEK: Well, I realize that, but
22 we've got things coming up, too, that I don't have
23 anybody to share with.

24 COMMISSIONER WEFALD: You could give that
25 job to Jerry.

1 MR. BINEK: Yes.

2 COMMISSIONER CLARK: In that case --

3 MR. HOBERG: Okay. Let's keep it
4 together. She's recording all this here now.

5 MR. BINEK: You got that "yes"?

6 MR. HOBERG: In other words, five weeks
7 from today; is that --

8 MR. BINEK: I think that probably works.

9 MR. HOBERG: So the late-filed exhibits in
10 a week, the transcript in three weeks, and findings
11 of facts, et cetera, five weeks from today.

12 MR. FAHN: Electronic versions, as well.

13 MR. HOBERG: Electronic version?

14 MR. FAHN: Yes.

15 MR. HOBERG: Okay.

16 MR. BINEK: That works.

17 MR. HOBERG: Anything else to bring to the
18 attention of the Commission before I ask for
19 closing comments from the Commissioners? Mr.
20 Binek?

21 MR. BINEK: No.

22 MR. HOBERG: Mr. Pearce?

23 MR. PEARCE: No.

24 MR. HOBERG: Anything else we need to
25 discuss? It's satisfactory? Okay. And in reverse

1 order, starting with Commissioner Clark, any
2 closing comments?

3 COMMISSIONER CLARK: Reverse order? I
4 would just say thank you to both sides. Both MDU
5 and staff did a very admirable job in presenting a
6 case and building a very good record for the
7 Commission to work with, and I thank them for that
8 and for a good hearing.

9 MR. HOBERG: Thank you, Commissioner
10 Clark. Commissioner Wefald, please.

11 COMMISSIONER WEFALD: There's a daunting
12 amount of material here that we've been presented
13 with over the last few days and many interesting
14 numbers to go over, and I echo Commissioner Clark's
15 comments about the good presentation from both
16 sides. It takes a great deal of work to prepare
17 all of this, and we understand the importance both
18 to the ratepayers of MDU and to the company for
19 this particular case. So I know we'll all be
20 looking carefully at what additional information is
21 filed in making a careful examination of this whole
22 case. Thank you.

23 MR. HOBERG: Thank you, Commissioner
24 Wefald. Then it's approximately three o'clock, and
25 we'll close this hearing. Thank you very much,

1 everyone.

2 (Concluded at 2:57 p.m., Tuesday, the 26th
3 day of February, 2002.)

4 -----

5

6

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25

CERTIFICATE OF COURT REPORTER

I, Stephanie A. Smith, a Registered
Professional Reporter,

DO HEREBY CERTIFY that I recorded in
shorthand the foregoing proceedings had and made of
record at the time and place hereinbefore
indicated.

I DO HEREBY FURTHER CERTIFY that the
foregoing typewritten pages contain an accurate
transcript of my shorthand notes then and there
taken.

Dated at Bismarck, North Dakota, this 13th
day of March, 2002.

Stephanie A. Smith
Registered Professional Reporter

