

1
2
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

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

- - - - - X

IN THE MATTER OF: :

ORDER NO. 720, PIPELINE POSTING : Docket Number

REQUIREMENTS UNDER SECTION 23 OF THE: RM08-2-000

NATURAL GAS ACT :

- - - - - X

Hearing Room 2C

Federal Energy Regulatory Commission

888 First Street, N.E.

Washington, D. C. 20426

Wednesday, March 18, 2009

The above-entitled matter came on for technical
conference, pursuant to notice, at 9:00 a.m.

BEFORE:

Anna Cochrane, Presiding.

1
2

1 APPEARANCES:

2 Federal Energy Regulatory Commission:

3 William Murrell

4 Jerome Pederson

5 Christopher Ellsworth

6 Christopher Peterson

7 Arnie Quinn

8 Steven Reich

9 Gabriel Sterling, III

10 Panels:

11 Roger A. Farrell

12 President & COO

13 Southern Union Gas Services, Ltd. (on behalf of TPA)

14

15 Larry Black

16 Manager, Gas Purchases and Transportation

17 Southwest Gas Corporation

18

19 Vonda Seckler

20 Managing Executive, Gas Supply

21 Ameren Corporation (on behalf of AGA)

22

23 Robert W. Young

24 Director of Scheduling

25 Energy Transfer (on behalf of TPA)

1
2

1 APPEARANCES (Continued):

2 John Ellis

3 Senior Counsel

4 San Diego Gas & Electric/Southern California

5 Gas Company

6

7 Bridget Shahan

8 Assistant General Counsel & Chief Compliance Officer

9 Nicor Gas

10

11 Michael Novak

12 Assistant General Manager, Federal Regulatory

13 Affairs

14 National Fuel Gas Distribution Corporation (on

15 behalf of AGA)

16

17 John Ellis

18 Attorney

19 San Diego Gas & Electric/Southern California

20 Gas Company

21

22 Will McCandless

23 Director Pipeline Portfolio - Commercial Operations

24 Exogex LLC (on behalf of TPA)

25

1
2

P R O C E E D I N G S

1

(9:00 a.m.)

2

3

MS. COCHRANE: Good morning. I'm Anna Cochrane.
Acting Director of the Office of Enforcement.

4

5

On November 20, 2008, the Commission issued a
Final Rule in Order Number 720, Pipeline Posting
Requirements, under Section 23 of the Natural Gas Act, which
amended Part 284 of the Regulations to require, among other
things, major non-interstate natural gas pipelines to post,
on a daily basis, certain information regarding scheduled
volumes of natural gas to be transported.

10

11

12

Requests for rehearing of the Rule, were filed on
December 22nd. On January 15th of this year, the Commission
granted an extension of time for major non-interstate
pipelines to comply with the requirements of the Rule, until
150 days following the issuance of an Order on Rehearing.

14

15

16

17

On February 24th and March 11th, the Commission
issued Notices announcing this Technical Conference, to be
held regarding certain issues raised on rehearing of Order
Number 720.

19

20

21

The Notices identified three topics for
discussion: One, the definition of "major non-interstate
pipelines;" two, what constitutes scheduling for a receipt
or delivery point; and, three, how the 15,000 MMBtu per day
designed capacity threshold should be applied.

22

23

24

25

1
2

1 The March 11th Notice provided an agenda with
2 specific questions on these topics, and announced the panels
3 to be held today, including a panel on compliance costs.

4 The purpose of this conference is for Commission
5 Staff to gather more information and explanation to better
6 understand technical issues that were raised in certain
7 rehearing requests.

8 We're not here to discuss the merits of Order
9 Number 720, or issues beyond those listed in the Notices.
10 We understand that certain parties have argued in comments
11 and on rehearing, that the Commission lacks the
12 jurisdictional authority to promulgate the Rules in Order
13 No. 720, and others, that there was a lack of notice for the
14 decisions made.

15 Those arguments and others, will be addressed in
16 the Commission's Order on Rehearing, and we do not intend to
17 discuss them today.

18 The topics on today's agenda were chosen because
19 we felt that additional information would better inform the
20 record and assist the Staff and the Commission in addressing
21 these issues on rehearing.

22 I'll note that we have a Court Reporter with us
23 today, so that the transcript of this proceeding will be in
24 the record. I know that this a rulemaking, and so there
25 aren't ex parte considerations for discussing things with

1
2

1 Staff, but we felt that in order to have this discussion
2 and be able to rely on the discussions that we might have to
3 further address these issues, it would be good to have them
4 in the record, so that's a driving factor behind this
5 conference.

6 No one should interpret the selection of issues
7 discussed here, to be indicative of the Commission's
8 ultimate determination on these or other issues raised in
9 the rehearing request.

10 Before I start, I note that any of the views that
11 may be expressed during this conference, by me or by any of
12 the other Staff members participating today, are our own
13 individual views and do not reflect the views of the
14 Commission, the Chairman, or any individual Commissioner.

15 So, with that, with me at the table to day, are
16 Jerry Pederson, Dr. Arnie Quinn, Steve Reich, Chris
17 Peterson, Chris Ellsworth, and Gabe Sterling, all with the
18 Office of Enforcement.

19 The panelists have been asked to provide a
20 response to the questions that were listed in the March 11th
21 Notice, limiting those comments to about five minutes.
22 After each of the panelists has made their presentations,
23 Staff will then ask questions.

24 So the first is panel is designed to review
25 structural issues in the Commission's designation of major

1
2

1 non-interstate pipelines, and I really appreciate you coming
2 today to talk about this issue.

3 We have Roger Farrell, President and Chief
4 Operating Officer of Southern Union; Larry Black, Manager of
5 Gas Purchases and Transportation for Southwest Gas
6 Corporation; and Vonda Seckler, Managing Executive, Gas
7 Supply, for Ameren Corp.

8 And I misplaced my agenda, but I understand that
9 -- so, Roger, you're speaking on behalf of the Texas
10 Pipeline Association, correct? Larry Black, Southwest Gas
11 Corporation, filed their own Request for Rehearing, and
12 Vonda Seckler is speaking on behalf of American Gas
13 Association.

14 Thank you very much. We can just start.

15 MR. BLACK: We have passed it back and forth,
16 that maybe I would go first, if that's all right.

17 MS. COCHRANE: Okay, if you guys have come up
18 with an agreement, that's fine.

19 MR. BLACK: I need to turn this light off.

20 MS. COCHRANE: Yes, you just flip it.

21 MR. BLACK: Thank you. Good morning, ladies and
22 gentlemen. Thank you.

23 For no other important reason, other than the
24 record, I would note that my title is actually Director of
25 Gas Supply.

1
2

1 Now, this is a perfectly good title from a few
2 years ago, but it has changed.

3 I'm here representing Southwest Gas Corporation,
4 to address the first issue on your agenda, defining "major
5 non-interstate pipelines," and the first two points
6 thereunder on the agenda, and how they apply to the 50
7 million decatherm threshold for reporting that's been set
8 forth in the Order.

9 The heart of the issue, we believe, emanates from
10 the purpose for which the information is to be reported.

11 With the understanding that the requested data is
12 meant to further the Commission's understanding of what
13 activities impact the natural gas market and where an impact
14 takes place, we believe that Southwest represents a logical
15 example of why the segregated or non-contiguous systems
16 should be viewed that way, independently, for purposes of
17 meeting that threshold.

18 I would note that I've been doing this for many,
19 many years, both in the interstate pipeline business, the
20 producer side, and now for many years with the LDC.

21 I believe that there's a terminology question
22 that always comes up. There may not be any regulatory or
23 legal distinction, but when anybody in the industry talks
24 about pipelines, an interstate pipeline, an intrastate
25 pipeline, quite frankly, they never visualize a local

1
2

1 distribution company in that conversation.

2 There are, of course, interstate and intrastate
3 pipelines, some of which also own distribution companies,
4 many of which do not, but when someone talks about the
5 pipelines, they typically are not talking about the
6 distribution company.

7 Southwest has six operating divisions located in
8 three states. I have prepared a little map, and I apologize
9 for its somewhat crude nature. It was not designed for this
10 purpose, but I tried to put it forth to just give you an
11 indication of where these areas are, as I talk about them.

12 They are not interconnected with each other in
13 any way; they're not separate legal entities, though they do
14 represent different state jurisdictional areas.

15 One might ask, well, why are these systems
16 segregated this way, or non-contiguous? The answer to that,
17 is simply that they were built at different times, in many
18 cases, by different companies, and always to serve different
19 markets.

20 Southwest began its distribution business in the
21 area of Southern California, where the Company actually
22 started as a propane company. I will add that if you look
23 at this map, don't let it be misleading.

24 The shaded areas that you see on there,
25 represent Southwest franchise territories. That's not to

1
2

1 imply that there are, indeed, distribution lines throughout
2 every bit of that shaded area. Much of that is desert with
3 cactus and jack rabbits in it, but it is a franchise area.

4 Somewhat later, they built the new distribution
5 system in southern Nevada, primarily to serve the Las Vegas
6 area, and, later still, a new system in northern Nevada, to
7 serve the few people that lived in northern Nevada at that
8 time.

9 These created the Southern California, Southern
10 Nevada, Northern Nevada Divisions that we refer to. They
11 are all geographically separated and they are all
12 independent of each other.

13 In 1979, Southwest acquired the gas distribution
14 business of what was then Tucson Gas and Electric Company,
15 thus forming what we now would refer to as our Southern
16 Arizona Operating Division.

17 In 1984, Southwest acquired the gas distribution
18 business of Arizona Public Service, forming what we now
19 refer to as the Central Arizona Distribution Business.
20 Clearly, those were separate businesses owned by separate
21 companies, and were not connected then and are not connected
22 with each other now.

23 Part of what is now Northwest and Northern
24 California area, was acquired in earlier years. In 2005, we
25 acquired the distribution business of Avista Corporation,

1
2

1 around the Lake Tahoe area, thereby completing what we now
2 refer to as our Northern California Operations.

3 Some of these are separated by state borders,
4 some by hundreds of miles, some by the fact that they were
5 built by different companies at different times, and all
6 were built to serve different markets.

7 Today, they are all Divisions operated by
8 Southwest Gas.

9 Because of their construction and their
10 operation, and, in most cases, also their geographical
11 separation, the operations and the usage in any one of these
12 segregated systems, does not really impact the marketplace
13 that's associated with one of the others.

14 In all of these six, except one, the demands are
15 heavily weighted to residential, small commercial, heat-
16 sensitive load like you would anticipate from a distribution
17 company, the one exception being Southern Nevada, where we
18 do have a substantial load behind our system of power plant
19 operations.

20 Four of the six areas are relatively small, and,
21 independently, would fall well below the 50 million
22 decatherm threshold, but, more importantly, really, because
23 of the size and the makeup of the market demands on them,
24 reporting data pursuant to Order 720, would not really
25 contribute any meaningful addition to the marketplace

1
2

1 intelligence that we believe you are trying to gather.

2 I'll close with just a few details concerning all
3 of our distribution areas, much of which I think will also
4 relate to what you'll hear in the later panels.

5 Aside from the usual bundled retail sales, all of
6 the transportation service that's done for others on our
7 distribution systems, is only for our end-use customers who
8 are behind our system.

9 And it's all done pursuant to state-regulated
10 tariffs and state-approved agreements. Southwest does not
11 schedule gas to end users off any delivery points on its
12 system, nor does it schedule gas across its system.

13 No gas or capacity can be traded between parties
14 on our facilities.

15 In every area, actually, Southwest serves as the
16 operator and gatekeeper for deliveries from an upstream
17 pipeline. In all cases but one, that's an interstate
18 pipeline.

19 The exception to that is the Southern California
20 area, where our facilities are located entirely behind the
21 facilities of Southern California Gas Company and PG&E. We
22 have no interstate connections at all there.

23 And those points where we do receive that gas on
24 the interstate system, are all at known, existing interstate
25 scheduling points. Our facilities, our only receiving

1
2

1 points there, in all areas except Southern Nevada, which is
2 an exception I'll discuss, all the gas scheduled to
3 Southwest by an upstream pipeline, is scheduled to what we
4 would refer to as virtual delivery points.

5 They are receipt points for Southwest, behind
6 which there are anywhere from several to many meters, but
7 none of which are actually scheduled interconnections.

8 Only in Southern Nevada, do we have direct
9 single-meter interconnects where gas is scheduled by the
10 upstream interstate pipeline company, and that information,
11 of course, is available as what's scheduled there and what
12 the available capacity is there.

13 It's also the information that's already being
14 reported by the interstate pipeline company.

15 With that, I believe I will conclude and say
16 thank you for the time to speak to you.

17 MS. COCHRANE: Do you have a preference for who
18 goes next? Vonda?

19 MS. SECKLER: Good morning. I represent Ameren,
20 who is a member of AGA, and the Ameren Corporation has four
21 LDCs: One in Missouri, Union Electric, and three in
22 Illinois, Central Illinois Light Company, Central Illinois
23 Public Service, and Illinois Power Company.

24 All four of these LDCs were formed by a series of
25 acquisitions to form Ameren Corporation's LDC Group, mostly,

1
2

1 independently operating, except for a few emergency
2 interconnects between the Illinois facilities, and those
3 interconnects are only used for emergency system operating
4 purposes.

5 Within each of these LDCs, there are many non-
6 contiguous systems, small load centers, mostly residential
7 and small commercial heat-sensitive load.

8 I've provided you with one example of a map of
9 the Central Illinois Public Service System, which represents
10 the non-contiguous areas of our systems. Within that
11 Central Illinois Public Service System, there are about
12 seven different service areas, and on that map, you can see
13 that there's mostly non-contiguous areas.

14 Very few of these are interconnected with each
15 other. Some are served by one pipeline, some are served by
16 more than one pipeline, but they are typically not
17 interconnected within each other.

18 If our companies are looked at individually, only
19 one of the Illinois LDCs would meet the 50-million delivery
20 threshold. We contend that, as an LDC, that we should be
21 permitted to look at our non-contiguous areas.

22 These are areas where there is no market being
23 developed, just by the nature of the customers that are
24 behind those gates, heat-sensitive, and we would like for
25 clarification that when we look at the delivery threshold

1
2

1 facility-by-facility, that the non-contiguous areas could be
2 segregated and looked at on their own merits.

3 MS. COCHRANE: Thank you. Mr. Farrell?

4 MR. FARRELL: Thank you. Just for a point of
5 reference, I come here with a background of -- actually, I
6 have an engineering degree, and I actually have designed
7 facilities and gathering systems; I've operated them, I've
8 been involved in the nomination, scheduling, and, of course,
9 at the management level.

10 So I'm coming with a background of experience. I
11 want to address, on behalf of the Texas Pipeline
12 Association, the questions that have been posed concerning
13 stub lines and the non-contiguous nature of the 50 million-
14 decatherm threshold.

15 I'm also going to recommend some solutions that
16 would allow us to capture the information that would further
17 your objectives, while minimizing the demands and burdens on
18 our industry. Obviously, our industry, like many
19 industries, is in difficult times today.

20 If you don't mind, can I just make some quick
21 sketches up on the board? I want to just -- and you may
22 have seen a lot of this before.

23 I'm going to talk a little bit about the
24 gathering system.

25 MS. COCHRANE: Could you just wait a second? Let

1
2

1 me check with the -- can you hear him, if he's over there?

2 (Pause.)

3 MR. FARRELL: I can speak fairly loud, so you'll
4 hear me. I'm just going to sketch a gathering system.

5 A gathering system has three functions: To
6 aggregate supplies --

7 MS. COCHRANE: I'm sorry, just logistically,
8 could you -- what were you suggesting, Andrew?

9 (Discussion off the record.)

10 MR. FARRELL: All right, the third time's a
11 charm.

12 MS. COCHRANE: We'll flip it around for the
13 audience, when you're done with your sketch.

14 MR. FARRELL: All right. A gathering system has
15 three functions: Aggregate supply, condition gas, and get
16 it to market, okay?

17 The aggregation piece starts off with the wells,
18 and most gathering systems connect hundreds, if not
19 thousands of wells, okay?

20 We connect them with lines, and then we install
21 compressor stations sometimes, take it from low pressure to
22 high pressure, and these wells have Btu contents anywhere
23 from 300 Btu per cubic foot, up to 1400, 1500 Btu per cubic
24 foot.

25 They contain liquids, they contain hydrogen

1
2

1 sulfide, CO₂, the full gamut, not -- you know, there are
2 some wells that are pipeline quality, by nature, but
3 certainly, in the majority of the cases, the gas has to be
4 conditioned in order to be sold, to be sold into the
5 interstate or intrastate commerce, okay?

6 The Btu content of 1050 or less, would be
7 required. So, essentially, we gather all these wells, and
8 this is just a single system; we come down here and before
9 we do anything, we run it through a dehydrator.

10 We take out water, because when the wells produce
11 gas, the gas is typically saturated with water vapor, and
12 that water vapor, before it goes into a processing plant,
13 had better be taken out or it's going to freeze and clog up
14 my system, and certainly you can't go into the downstream
15 pipeline with water.

16 Downstream pipelines have seven pounds or less.
17 After you dehy, you do -- you treat. If you treat, you take
18 out CO₂, you take out hydrogen sulfide, you can take out
19 nitrogen, which is a whole different process, but you take
20 out nitrogen.

21 Those are unwanted components in a gas stream.
22 Once again, there are certain levels that you cannot, if you
23 don't take them out, you'll get shut in by the downstream
24 pipelines.

25 After you do that, you process the gas. We call

1
2

1 processing essentially -- you know, we cool the gas down to
2 minus-150 to minus-200 degrees Fahrenheit, and what happens
3 there?

4 The liquids fall out. All the liquids, with the
5 exception of methane and some ethane, everything else falls
6 out. Most of the ethane falls out, butanes, propanes,
7 natural gas liquids, and all those have to be taken out
8 before they go to the market. Once again, the interstate
9 pipelines cannot take the gas, for the most part -- there
10 are some gathering systems with some gas that's produced,
11 that is pipeline-quality, but many and a lot of it is not,
12 and so this a vital piece.

13 These liquids, natural gas liquids, come out of
14 the processing plant, and at least the majority of us go to
15 Mt. Bellvue, Texas, through pipeline networks or Oklahoma,
16 Kansas area, for fractionation.

17 Once we've gone through this whole train, we now
18 have gas that is fungible, we can sell it into the
19 marketplace. Okay, at these plants, we go into the stub
20 lines.

21 Stub lines essentially will be a high-pressure
22 line, for the most part, and that will be pressure
23 sufficient to get into the market. The intrastates, the
24 interstates, possibly an end user, but, typically, the
25 intras and inters.

1
2

1 So, you come out of the plant, and these stub
2 lines go from a few hundred feet, to miles. And the stub
3 lines, all they do is, they get you to market, okay?

4 An individual plant may go to one market, it may
5 go to two markets, it may go to five markets; it depends on
6 where you are on the grid. For our purposes, we want to
7 have as many markets, for a couple of reasons:

8 Number one is, it's a competitive environment, so
9 the better markets that we have, obviously, we can offer
10 better deals, so to speak, on a commercial end, plus, if you
11 have one market, what happens if your market, the interstate
12 pipeline, goes down for maintenance? You're shut in;
13 there's nowhere to take your gas.

14 So, typically, you try to lay these stub lines to
15 local markets, okay? And the market is very, very
16 efficient. I mean, we -- you know, the price discovery that
17 you can get in the interstates and the intrastates, you
18 know, we're very good at trying to find where the best deal
19 is for our customers.

20 There can be more plants connected to one system,
21 you can have a couple of plants, and that's where you get
22 into the contiguous/non-contiguous situation.

23 Southern Union itself, we have four plants.
24 We're connected to stub lines that are interconnected, they
25 go to multiple markets. The markets are always the intras

1
2

1 and the inters, okay?

2 We have companies in the Texas Pipeline
3 Association, that have gathering systems in different
4 states, connected to different intrastates and interstates.

5 You know, from our perspective, the 50 million
6 decatherms, if reporting is done on the 15 million a day
7 threshold, into the intrastates and into the interstates,
8 essentially all this gets captured, okay?

9 It gets captured and it's just a matter of how
10 many times we want to capture it, capture the same
11 information. One day, we may be going somewhere, next day,
12 we may be going to a different place.

13 But at the end of the day, whether you're
14 contiguous or non-contiguous, if you have enough volume
15 going into the intras and inters, those volumes will be
16 captured under a 15-million-a-day-threshold on the delivery
17 side.

18 So that is the purpose of the stub lines.

19 Now, let me -- we agree -- and there was
20 something in the Order that talked about -- that said that
21 the Commission said that the supplies upstream to a
22 conditioning plant, are not fungible, and we agree with
23 that.

24 And, moreover, supplies upstream of a
25 processing/conditioning/treating plant, those are not

1
2

1 pricing points; it's not bought and sold upstream of the
2 plant.

3 Furthermore, upstream of a plant, about 99
4 percent of the meters for the wells, supply sources,
5 upstream of a plant, fall below the 15 million a day
6 threshold.

7 Most of the wells in this country are small --
8 thousands, tens of thousands, so capturing any data upstream
9 of a plant, really does not serve the purpose of really
10 capturing the essence of the volumes flowing into the
11 marketplace.

12 We're going to talk, with the subsequent
13 speakers, the nomination and scheduling process that we
14 think works well to capture the volumes that come out of the
15 processing, and, also, I think, address some of the concerns
16 of the local distribution companies.

17 As I said, the contiguous -- we're contiguous; a
18 lot of companies are not contiguous, but if you have the
19 right 15 million a day threshold on the inters and intras,
20 you will capture the LDC business, you will capture the
21 gathering business.

22 So it's a matter of how redundant do we get in
23 reporting volumes. In the case that I laid out here, what
24 would we report? Certainly reporting into the markets, is
25 doable. There would be a handful, you know, five to ten,

1
2

1 depending on how massive you system is.

2 The intrastate pipelines are a different matter.
3 They're much more flexible, they have more ability to move
4 gas between points, they might take gas in from other
5 pipelines, or back out, they're much more complex.

6 But at the end of the day, what they do, is move
7 gas very efficiently from markets here to markets there,
8 probably mostly driven by price or demand.

9 Now, the difference there, also, is that many of
10 the intrastates have truly markets attached to them, and
11 whether it's an electric generation plant, whether it's
12 flowing into an LDC, fertilizer plant, they probably are
13 going to have some sort of a market.

14 But once again, deliveries over 15 million a day
15 would be captured on the supply side and on the market side.

16 So what I would like to come away with -- you
17 know, I'm probably kind of revisiting this thing, but I
18 believe that a gathering exemption would be warranted, but
19 if you don't believe that a gathering exemption is
20 warranted, I want to be very clear that we see points
21 upstream of a gathering system, do not need to be reported,
22 because they won't provide meaningful information to the
23 Commission or to anyone else.

24 Then also I'd like to propose that we adopt the
25 posting requirements that we're going to proffer in the next

1
2

1 segment, that I think resolves a lot of the issues and
2 concerns of the LDCs, and some of the other market
3 participants.

4 And with, that, I'll conclude my remarks.

5 MS. COCHRANE: Thank you very much. Does Staff
6 have questions?

7 MR. REICH: Thank you very much. Mr. Farrell,
8 there were a number of questions or a number of items. One
9 of the issues raised in the Rehearing Request, was something
10 about gathering lines that don't go through processing
11 plants.

12 And can you explain a little, how that works,
13 versus the chart that you put together?

14 MR. FARRELL: I'll address it two ways, and I
15 don't know exactly what was discussed. I know when I came
16 in, there were some discussions, but, you know, the stub
17 lines, to me, serve a purpose, you know, that they are a
18 gathering facility that serve a market access function,
19 solely.

20 It's possible to have gathering lines that are
21 not treated or processed, and maybe are just dehy'd or
22 possibly dehy'd by the producer at the wellhead, that would
23 -- could go into a market, directly.

24 That would be about the only one I would, you
25 know, the only gathering function that would be downstream

1
2

1 of a process facility that I could come up with.

2 MR. REICH: Is that common?

3 MR. FARRELL: There are a lot of gathering
4 systems that go directly into intrastates and interstates,
5 that do not -- that are not processed.

6 The gas is -- I mean, I don't know relative
7 volume, but there is gas that is pipeline quality that
8 doesn't need processing. But, once again, if there are
9 large volumes, if they are over 15 million day, into the
10 inter or intra, they would be captured under the Rule.

11 MR. REICH: Thank you, thanks. I have one
12 question about stub lines. In terms of the definition of
13 "stub lines," do they -- is it possible for stub line to
14 serve a customer directly, or does it -- or do they
15 generally just go into the inter and intra?

16 MR. FARRELL: By far, they go into inters and
17 intras. Are there cases where they go to a customer?
18 Probably so, but I don't -- you know, I don't have any
19 anecdotal numbers to say what percentage, but it wouldn't be
20 very large.

21 MR. REICH: Thank you.

22 MR. PETERSON: Yes, Mr. Farrell, I have a couple
23 of followup questions for you. Can you characterize the
24 typical output of the plants you've drawn up here?

25 I suspect it's a range, but can you give us a

1
2

1 flavor for the magnitude of the million cubic feet per day
2 ranges for these facilities?

3 MR. FARRELL: Of course, it's economy of scale,
4 but I've been associated with plants that have been five or
5 ten million cubic feet a day outlet. The typical plant that
6 we deal with today, is probably more along the lines of 100
7 million cubic feet a day, but there are many plants that
8 are much greater than that, around our producing region, and
9 there are plants that are probably 400 million cubic feet a
10 day.

11 And then in your discussion, I think when you
12 talk about taking the gas to market, what do you mean? More
13 specifically, what's the market you're suggesting that the
14 output of these plants goes to?

15 MR. FARRELL: The market, literally, are sales
16 delivered into intrastates or interstates.

17 MR. PETERSON: And when you say that given the
18 range of the output sizes of the volume leaving the tailgate
19 of these plants, I think what you're getting at, is that
20 these could show up as interconnected receipts for other
21 parties, whether they are interstate natural gas pipelines,
22 for which we would already see those volumes, presumably, or
23 for the major non-interstate systems that this Rule aims to
24 get better coverage of; is that correct?

25 MR. FARRELL: That would be correct.

1
2

1 MR. PETERSON: And I think you just said you're
2 not sure how much of the gas that is pipeline quality, that
3 does -- it is able to skirt going through processing,
4 because it already has, you know, chemical or, you know,
5 water attributes that are sufficient that it can free-flow
6 on the system.

7 We've talked about this internally. Do you have
8 any guidance you can give us for how big that is?

9 MR. FARRELL: In the marketplace, I don't. I
10 will say that I know that we have a system that can flow,
11 you know, 100 million cubic feet a day, and go directly to
12 market.

13 Now, that volume will be captured by an
14 intrastate pipeline.

15 MR. PETERSON: Right.

16 MR. FARRELL: But, I mean, going back through my
17 history, I would say -- and I'm, you know -- well over 50
18 percent is going to have to have some sort of -- I mean,
19 certainly dehydrated, and depending on what basin you're in,
20 there will be some level of treating or processing.

21 MR. PETERSON: I guess, lastly, in terms of
22 deliveries out of your system, do any of this gas go
23 directly to end users, or, more typically, is it nearly
24 always carried through either an interstate network or a
25 major non-interstate system?

1
2

1 MR. FARRELL: Your last statement is correct.
2 Gatherers go to other companies who take the pipeline
3 quality gas to the downstream market, and those -- the
4 receiving pipeline off the stub line, will be major non-
5 interstate. You know, there are certainly some in TPA in
6 Oklahoma, in Texas, and Louisiana, or the interstate.

7 And they will be the ones, typically, that have
8 the connected end users, and, certainly, the intrastates
9 will or may go to the interstates, as well, so, basically,
10 the gas can go to wherever it's needed.

11 But the intrastates are very -- have very
12 flexible systems that allow gas to go bidirectional in their
13 systems at times. They have a lot of compression at key
14 points, but they're just -- the capability, certainly of the
15 larger ones, are just very good at finding where the best
16 value is for the customer.

17 MR. PETERSON: Thank you.

18 MR. REICH: Now we'll turn to Ms. Seckler and Mr.
19 Black.

20 Ms. Seckler, you raised in your presentation, you
21 talked about your four operating companies. Is that the
22 right term that you used?

23 MS. SECKLER: That's correct.

24 MR. REICH: And that they are non-contiguous, and
25 then within those companies, there are various non-

1
2

1 contiguous companies.

2 MS. SECKLER: Correct.

3 MR. REICH: Am I correct?

4 MS. SECKLER: Yes.

5 MR. REICH: Is there a way that we can
6 differentiate -- well, how do you differentiate what makes a
7 non-contiguous part of a single system, versus non-
8 contiguous operating companies within your overall Ameren
9 umbrella?

10 MS. SECKLER: Well, the four LDCs are separate
11 legal entities, and then within one of the legal entities,
12 there's various non-contiguous service territories, so it's
13 delineated by the legal operating entities and then within
14 those operating entities, that whole service territory is
15 operated, I guess.

16 MR. REICH: I mean, do they -- are they operated
17 by -- you know, do they have different control rooms?

18 MS. SECKLER: No, there is one control room for
19 everything. We nominate on the interstate pipelines,
20 individually, by LDC, and then the control rooms move that
21 gas, based on those nominations on interstate pipelines
22 through the distribution areas.

23 MR. REICH: So they nominate individually; they
24 operate together?

25 MS. SECKLER: Yes.

1
2

1 MR. REICH: And in terms of the contracting and
2 gas supply and all that, that is a shared function?

3 MS. SECKLER: Well, the contracts with
4 interstate pipelines are separate, by legal entity.

5 MR. REICH: So the transportation contracts are
6 separate; supply -- you --

7 MS. SECKLER: Supply contracts are separate, by
8 legal entity, also.

9 MR. REICH: Okay. Mr. Black, is that similar on
10 Southwest?

11 MR. BLACK: Yes, I believe that's similar. We,
12 while we're one legal entity, if you will, hold
13 transportation contracts on the upstream pipelines for each
14 of the different areas.

15 Certainly, it needs to be done so for the state
16 jurisdictional differences. There is a centralized
17 purchasing function, but the supply contracts for the gas
18 supplies are done separately, and the transportation
19 arrangements that are held by contract, are also separate
20 for each of those.

21 MR. REICH: Both of you talked about parts of
22 your -- if you look at individual parts of your
23 organizations, your companies, certain parts would still fit
24 under the 50 million MMBtu, versus the ones that didn't fit
25 under it, if you treated them separately.

1
2

1 Is there, in terms of operations associated with
2 larger customers, power plants and such, is -- for the
3 larger parts of your entities, do they -- is there some way
4 -- how are those treated in those entities, versus how power
5 plants or large customers would be treated in the smaller
6 parts, entities, of your company?

7 MR. BLACK: I'll stake a stab at that.

8 (Laughter.)

9 MR. REICH: I'm sorry, I may have gotten lost in
10 the middle of that.

11 MR. BLACK: I think I've got the question. By
12 and large, the only real major on-system transportation
13 loads we have, would be in our Southern Nevada area, which
14 has a substantial power plant -- a series of power plant
15 loads behind that and on that distribution system.

16 They're not really handled any differently, other
17 than as with any major customer, particularly one who has
18 what may be a volatile load pattern like a power plant might
19 be. We have much more ongoing and regular communications
20 with those customers about what their plans are for the
21 day, the gas that they intend to get delivered through our
22 system for their use that day and so forth, where in most of
23 our service territories, the demand, other than our
24 residential heat-sensitive load, is a commercial/industrial
25 load that's fairly flat, fairly regular on a day-to-day

1
2

1 basis, and really doesn't require a lot of hour-to-hour, or,
2 you know, minute-by-minute communication.

3 So that's really the only difference. The tariff
4 practices and the agreements that we have with those
5 companies, are essentially similar, but, certainly, you have
6 a different relationship with a major power plant that's
7 behind your distribution system, just as a passing of
8 knowledge back and forth between their operators and our gas
9 control people, so you will have some ongoing idea of what
10 they may be doing from time to time.

11 MR. REICH: That's exactly what I was asking.

12 MS. SECKLER: Ours is similar to Southwest Gas.
13 The only thing I would add, is that those power plants and
14 industrial loads that are behind our system, we still -- and
15 I think they're going to get into this in the next panel --
16 but we still don't schedule to their meters; they still
17 schedule to the interconnect with the pipeline, and then we
18 basically balance their load with what they've scheduled,
19 based on our service tariffs that are filed with the state
20 commissions.

21 They could be scheduling on an interstate
22 pipeline for themselves, or a marketer may pool a bunch of
23 those customers together and schedule, but we don't schedule
24 the individual meters. I know that's on the next panel, but
25 I'd just like to add that to Larry's comment.

1
2

1 MR. BLACK: And I'd repeat that that's the same
2 for us. All of the deliveries off of our distribution
3 facilities, to any of those, say, generating plants, is all
4 done in accordance with the state tariff provisions, and we
5 don't do meter delivery scheduling to any of our end users.

6 MR. REICH: Thank you.

7 MS. COCHRANE: Chris?

8 MR. ELLSWORTH: Mr. Farrell, going back to the
9 processing plants and stub lines and things like that, I
10 think I read in the TPA comments, that there are instances
11 where there will be pipelines that actually bypass the
12 processing plant.

13 Assuming that is not pipeline-ready gas, where
14 does that gas typical go to? Is it being sold to a
15 petrochemical plant or something like that, and what kind of
16 transactions go on in that process?

17 MR. FARRELL: Well, certainly if it gets into a
18 major non-interstate pipeline, it's going to be pipeline
19 quality.

20 MR. ELLSWORTH: Okay.

21 MR. FARRELL: There may be instances where a
22 gathering line ties to a market, but that will be a very --
23 I can't say "rare," but it will certainly be an exception.

24 MR. ELLSWORTH: Okay.

25

1
2

1 MR. PEDERSON: Ms. Seckler, if I can go back to
2 the noncontiguous systems. I thought I heard you say that
3 the Illinois system operates independently but for certain
4 emergency situations. Did I hear that right?

5 MS. SECKLER: That's correct.

6 MR. PEDERSON: What are those situations?

7 MS. SECKLER: Well if there are pressure issues,
8 or if we have a major outage of like a company-owned storage
9 field; or it could be day to day, maybe weather changes. We
10 have basically one interconnect between each utility
11 distribution system for those type of situations.

12 MR. PEDERSON: And to your knowledge is that--
13 would that be typical of other non-contiguous systems? That
14 at certain times they do operate independently, and at other
15 times they kind of operate together?

16 MS. SECKLER: I would assume that that would be
17 the case, that they would have some kind of an emergency
18 operating contingency.

19 MR. PEDERSON: Would it only be under emergency
20 situations? Or could there be a circumstance where we've
21 got non-contiguous systems that are actually operating
22 together? Are you aware of anything along those lines, or
23 are any of the panelists?

24 MR. BLACK: I would just speak for Southwest, and
25 I certainly don't know what all the different LDC companies

1
2

1 have in their quiver for these issues. Our systems that
2 I've described to you are not interconnected in any way.
3 Clearly some of them are hundreds of miles apart, so they
4 wouldn't be. And even the two that appear to lay adjacent
5 to each other in Arizona were designed and built entirely
6 separately by different companies for different markets, and
7 they do not have an interconnect between the two in the
8 distribution side.

9 But I would think that it might be logical if you
10 have close lying places, as Ms. Seckler described, that that
11 would not be unusual. We don't happen to have that.

12 MS. SECKLER: And I guess I would add, too, that
13 where our systems are interconnected are basically where our
14 largest load areas area. If you look at the map down in
15 like southern Illinois, that's not connected to anything.
16 It's basically on its own. So other than it may have a
17 storage field, a company-owned storage field or something
18 for emergency purposes; but where our three Illinois
19 utilities are connected are all in the basically central
20 Illinois area where the service territory somewhat overlaps.

21 MR. FARRELL: It is possible that you could have
22 some non-contiguous systems coming into an interstate or a
23 major non-interstate into one. That volume could be pooled,
24 you know, for supply purposes or under an agreement, but if
25 the receipt points or the delivery points from these

1
2

1 non-contiguous systems into the major non-interstate or the
2 interstate exceed 15,000 MMBtu per day, or whatever
3 threshold you determine, those volumes will be captured
4 under the proposal that's in front of us.

5 MR. PEDERSON: Yes, and I guess part of what I'm
6 trying to go through my mind is, I think one of the issues
7 that's been raised is we should treat non-contiguous
8 separately. So there could be a circumstance, I think,
9 where neither of those systems meet the threshold but
10 together they might. And what I was querying is: Well, are
11 they operating separately, or not? Or is it kind of some
12 are, some aren't?

13 MR. FARRELL: Well certainly if I was a gatherer,
14 or if I was a producer that had non-contiguous gathering,
15 certainly from an operations standpoint they're operated
16 absolutely separately. They're different physical
17 facilities.

18 The only way--the only time that you would not
19 be, or once you--once you deliver into the marketplace, the
20 major non-interstate or the interstate, that is where they
21 become one, so to speak--or possibly.

22 Now to the extent that they're going into
23 disparate systems, you don't have the physical operations
24 and you certainly don't have the contractual ability to
25 combine the two.

1
2

1 MR. BLACK: I would just add, and sort of a
2 follow-up on what Mr. Farrell has said before, that in the
3 typical situation for Southwest whether these separate
4 operating divisions are interconnected or not, all of the
5 volumes that are delivered to us, to our facilities, will be
6 reported by the interstate pipeline because they're
7 delivered at known existing scheduling points on the
8 interstate pipeline.

9 So regardless of whether there might be--even
10 though there isn't an interconnect in our distribution
11 facilities--none of that volume will be lost in the
12 reporting function.

13 MR. PEDERSON: Thank you.

14 MS. COCHRANE: Did you have a question?

15 MR. STERLING: In addition to the physical
16 interconnection between these non-contiguous facilities, do
17 either of you two companies engage in integrated operations
18 through contract paths or other sorts of transportation
19 means on interstate pipelines or intrastate pipelines?

20 MR. BLACK: Well speaking for Southwest there are
21 some transportation contracts that we hold on the interstate
22 pipeline in Arizona that may serve both the central Arizona
23 and southern Arizona divisions for transportation service.
24 But again, each of those will be scheduled to known
25 scheduling points by the pipeline and that volume will be

1
2

1 captured, either way. And they will be point by point. So
2 I can't even remember right now exactly which points are in
3 our southern Arizona division off the pipe, and which are in
4 the central, because we have like 27 of them in one pipeline
5 company, and literally hundreds of actual meters behind
6 those points, but they would all be reported either way.

7 MS. SECKLER: And for Ameren we may have more
8 than one non-contiguous area on a single interstate
9 pipeline. So we may purchase one package of gas that gets
10 scheduled on an interstate pipeline that can be used to
11 various non-contiguous service territories through the
12 control of the distribution system. But it's still just
13 scheduled to one central delivery point on the interstate
14 and through the distribution system. We move the gas to
15 where we need it to serve load.

16 MR. STERLING: Thank you.

17 MS. COCHRANE: Any other questions?

18 (No response.)

19 MS. COCHRANE: Great. Thank you very much. I
20 really appreciate the visuals. I always like talking to gas
21 people because they always bring their maps. It's a lot
22 easier to understand with drawings.

23 Thank you, very much.

24 Panel two can come on up.

25 (Pause.)

1
2

1 All right, thank you very much. This is panel
2 two which addresses how to account for high capacity receipt
3 point and delivery points where scheduling does not occur.

4 So with us today are Robert Young, Director of
5 Scheduling for Energy Transfer, speaking on behalf of the
6 Texas Pipeline Association; John Ellis, Senior Counsel for
7 San Diego Gas & Electric and Southern California Gas
8 Company; Bridget Shahan, Assistant General Counsel and Chief
9 Compliance Officer for Nicor Gas; and Michael Novak,
10 Assistant General Manager for Federal Regulatory Affairs,
11 National Fuel Gas Distribution Corp., on behalf of the
12 American Gas Association.

13 I don't know if, like the last panel did you guys
14 decide who might go first? Okay, that's fine. So, Mike
15 Novak.

16 MR. NOVAK: Good morning. I am Mike Novak from
17 National Fuel Gas Distribution Corporation where I'm the
18 Assistant General Manager within our Rates & Regulatory
19 Affairs Department.

20 For nearly my entire 25-year career at National
21 Fuel I've been involved with some aspect of customer
22 transportation or another. This involvement included
23 responsibility for our Transportation Services Department
24 at a time when we designed and implemented our
25 transportation web site and scheduling systems. Nearly 50-

1
2

1 percent of the annual throughput on the National Fuel
2 Distribution System is customer transportation and we expect
3 this number to keep on growing.

4 Today I am speaking on behalf of the American Gas
5 Association. AGA supports the Commission's market
6 transparency efforts that are designed to foster greater
7 confidence in natural gas price formation.

8 Where LDCs have information that would be helpful
9 to the market in this regard, it is not unreasonable to
10 expect that LDCs would make this information available,
11 provided that it can be done on a cost-effective manner.
12 That said, it would appear as if some believe that scheduled
13 deliveries on LDC systems plays a greater role in market
14 price formation than is actually the case. I hope to be
15 able to shed some light on this today.

16 While LDCs have some similarities with intrastate
17 and interstate pipelines, LDCs are essentially distributors.
18 Even when an LDC provides a transportation service,
19 provision of such service does not morph the LDC into a
20 transmission provider. Whether an LDC is a statutory
21 obligation to serve, whether an LDC customer receives
22 bundled or unbundled service, the typical LDC customer
23 expects to be served.

24 LDCs operationally manage their systems to
25 service all customers with some limited exceptions that are

1
2

1 usually spelled out in tariffs that are approved by state
2 regulators.

3 As a general matter, LDCs do not consider market
4 prices when they determine how much gas is necessary to
5 serve the market on a daily basis. The expectation is that
6 the market is going to be served and, for the most part,
7 anticipated demand is going to be a function of weather and
8 historical load patterns.

9 Most receipts into LDCs are from interstate
10 pipelines. The amount of supply--for example,
11 production--connected directly to LDCs is relatively small.
12 In response to the amount of information required to manage
13 LDC transportation services, some LDCs have scheduling
14 systems and others do not.

15 These are the important factors in determining
16 whether LDCs have information relevant to market price
17 formation that is not available elsewhere, and the cost at
18 which that information can be provided.

19 Thank you.

20 MS. SHAHAN: Good morning. I'm Bridget Shahan of
21 Nicor Gas and I appreciate the opportunity for being here.

22 Nicor Gas, like most LDCs, has a reticulated
23 system. We have 96 receipt points from interstate
24 pipelines. We do not have any production directly connected
25 to our system. And we have 2.2 million delivery points,

1
2

1 mostly to residential customers.

2 Nicor is the provider of last resort to these
3 customers. And as an LDC, we wear two hats. We are the gas
4 supplier and we are also the system operator for our
5 transportation customers. We have approximately 15,000
6 transportation customers.

7 And 55 percent of the volumes that Nicor delivers
8 goes to bundled sales customers. 99.9 percent of the
9 volumes we deliver go to sales and transportation customers.
10 There's approximately about a .1 percent of the volumes
11 delivered to Nicor System that go to other LDCs or back to
12 an interstate pipeline.

13 Nicor has an annual delivery on its system of
14 about 500 bcf. Now Nicor also has two divisions within its
15 operations. There's the SCADA control room, which handles
16 the physical operations. It monitors the actual flow at
17 those 96 interconnects, and it is handling on a real-time
18 basis the pressure. It is dealing with maintenance issues.
19 It talks control room to control room to other interstate
20 pipelines, or to the interstate pipelines or other LDCs.
21 And when there are issues they have to handle them
22 immediately.

23 The other division is the Gas Supply Department.
24 It is making sure that sufficient gas is scheduled to the
25 city-gate. Now what they are doing is they are handling the

1
2

1 nominations, the schedules, and the confirmations. And for
2 our largest interstate pipeline supplier, which is Natural,
3 we have 75 physical interconnects but we have one scheduling
4 point for Natural, and Gas Supply is dealing with that one
5 central, or virtual, scheduling point.

6 Nicor then on its system, we have one Nomination
7 Cycle a day currently. What we do, the purpose of that is
8 to confirm what the shippers have scheduled upstream on the
9 interstate pipelines. Then we also use that information for
10 our billing purposes.

11 Now on a daily basis we know the scheduled
12 volumes that come into that central delivery point, and we
13 also know the actual volumes that go to that 96
14 interconnects. But as long as there are no issues or
15 problems on the system, they really don't have anything to
16 do with each other. It's only when there may be issues--
17 let's say volatility.

18 Volatility could be weather. It could be supply,
19 force majeure, maintenance, it could be demand. There's a
20 lot of possibility for what volatility could be. And if we
21 do have that volatility, then Nicor has tools to use.

22 We have our No Notice on the interstate pipeline
23 systems. We have storage on Natural's system. We can go
24 out in the Daily Market and buy if we think we need to get
25 more gas to our city-gate. Then we have OVAs for monthly

1
2

1 reconciliations with the interstates.

2 That is what we can do upstream.

3 Then on our own system, if we still have issues,
4 our shippers have a lot of flexibility because we have on-
5 system storage. And they have a certain number of days of
6 storage every year that they can use. So if they come up
7 short with an imbalance or too much, they can play with
8 their storage to correct their imbalance on a daily basis.

9 If for some reason they don't have any gas in
10 their storage, they can buy the gas from Nicor at its PGA or
11 Gas--I think it's greater, PGA or Gas Daily. And if they
12 brought in too much, they can also park it. And all of that
13 is based on our Illinois-approved tariff of what their
14 contractual rights are and their tariff rights are of how
15 they balance once they get on our system.

16 And then finally, Nicor also has the ability to
17 restrict and put OFOs, or critical days on its own system if
18 there really is an issue that is not being addressed by the
19 shippers. Usually there's a notice put out first like:
20 Well, we see warm weather coming. You may want to back off
21 on bringing gas in.

22 And if it doesn't happen and we have to do
23 something, then we will do something. Let me see if I've
24 covered all of what I wanted to say. Basically I just
25 wanted to say that also the transportation customers are

1
2

1 scheduling on the interstate to a virtual point. And then
2 they are scheduling once they come onto our system to what
3 we call pools, which are virtual points.

4 And those pools are really designed and created
5 by that transportation customer. That transportation
6 customer could be a franchised store that has multiple
7 locations around the state. So it has multiple meters in
8 its contract, and that's its pool, and it is bringing in a
9 certain amount of gas for those meters.

10 Or a transportation customer can have multiple
11 customers of its own. And again in that contract it is
12 going to have all those meters of those customers. And they
13 are just nominating into our system to a pool. And they are
14 really nominating to their own contract. And that is how we
15 do the end-of-the-month billing reconciliation.

16 They have nominated to their contract. End of
17 the month they figure out what their customers or those
18 meters actually took, and it is reconciled.

19 So thank you.

20 MS. COCHRANE: Thank you very much.

21 MR. ELLIS: Good morning. My name is John Ellis.
22 I am an attorney for Southern California Gas Company and
23 San Diego Gas & Electric Company. Thank you for the
24 opportunity to come here this morning and follow up on
25 issues and concerns the Staff raised in the Request For

1
2

1 Rehearing.

2 I have some presentation materials I will try and
3 talk to. The second slide is entitled Scheduling to the
4 city-gate. Much of what I have to say will be similar to
5 what you just heard from Mr. Novak and Ms. Shahan.

6 The first point is that over 90- percent of the
7 gas scheduled in the SDG&E and SoCalGas System and the PG&E
8 system comes from interstate pipelines where scheduled
9 quantities are already posted. The point here is that any
10 requirement of posting of information of receipts would be
11 duplicative to what is already available.

12 The second point is that both SDG&E/SoCalGas and
13 PG&E already post all scheduled supplies into and out of
14 their systems and any scheduled supplies into and out of
15 their storage fields. Those area available on our web
16 sites, on our electronic bulletin boards. The addresses for
17 those web sites are actually stated in footnote eight of the
18 Request For Rehearing filed by the American Gas Association.
19 And I believe Mr. Peterson of your staff has access to the
20 password-protected web site, and I believe a member of Dr.
21 Quinn's staff also will have that shortly.

22 The third point is a function of editing a
23 presentation while traveling and having access to the
24 presentation by Blackberry--the point is that both
25 SDG&E/SoCalGas and PG&E already post aggregated on system

1
2

1 demand information. This would be an aggregate of the
2 receipts of the different interstate interconnects from
3 California production. The question that's asked by one
4 commenter is: Is this true for SoCalGas? The answer is:
5 Yes, it is.

6 The next couple of slides are maps of the
7 facilities of PG&E and SDG&E/SoCalGas. These were exhibits
8 to the Request For Rehearing. They just give a graphic
9 representation or a pictorial representation of where we are
10 receiving supplies from, the interstates. For PG&E that is
11 primarily at Malin on the California/Oregon border, and
12 Topock at the border between California and Arizona. And
13 also from Kern River.

14 The second slide is--

15 MS. COCHRANE: Can I ask you a quick question
16 while we're on it?

17 MR. ELLIS: Sure.

18 MS. COCHRANE: What do you consider your city-
19 gate?

20 MR. ELLIS: The city-gate is behind the border.

21 MS. COCHRANE: On the map, where would you
22 consider the city-gate? How would you define that?

23 MR. ELLIS: The city-gate is a virtual point. It
24 is not a specific physical location. It is a point at which
25 pooled supplies can be traded, received in and out of the

1
2

1 system, but there is no one physical location.

2 MS. COCHRANE: I just wanted to clarify that.

3 MR. ELLIS: The next slide shows the five receipt
4 point zones for Southern California Gas Company and SDG&E.
5 These are a function of the Firm Access Rights Program that
6 went into effect October 1st, 2008. There is an allocation
7 of Receipt Point Rights through these zones that customers
8 hold, and these are the paths into the system into the city-
9 gate for Southern California Gas Company and SDG&E.

10 Again, the major receipt points are on the
11 California/Arizona border with the El Paso Natural Gas
12 Company System and the Trans Western Natural Gas Company
13 Interstate System, and then from Kern River, and then also
14 from California Production in the Line 85 Zone and the
15 Coastal Zone.

16 The next slide addresses the issues of--begins to
17 address the issues of concern in Order No. 720. It's
18 Scheduling Downstream of the city-gate.

19 The first point is that the majority of gas
20 scheduled into our system is scheduled through the city-gate
21 and through city-gate Pooling Accounts. Some gas is
22 scheduled directly beyond the city-gate, but most comes
23 through Pooling Accounts at the city-gate. There is a
24 Nomination Model at Slide 10 of this presentation that will
25 show the--that shows the Scheduling Model.

1
2

1 So for SDG&E/SoCalGas after gas is scheduled
2 through the city-gate, it is then scheduled one of three
3 places: customer pool accounts, storage accounts, or back
4 off the system. Currently for SoCalGas and SDG&E there is
5 only one location to schedule back off the system and that
6 is to the PG&E System. We have an application to the
7 California Public Utilities Commission for authority to
8 confirm scheduling back to interstate. That authority has
9 not been granted to date. We expect it to be granted, but
10 currently the off system delivery for SDG&E/SoCalGas are
11 only back to PG&E.

12 The last point--and this is where we begin to get
13 into the issue that has been addressed already by Mr. Novak
14 and Ms. Shahan--SDG&E and SoCalGas have no requirement or
15 operational need to have gas supplies nominated and
16 scheduled to specific end-use delivery points.

17 Turning to the next slide, we have approximately
18 1,000 end-use customers who participate in our
19 state-Commission approved transportation Program; and an
20 estimate 110 end-use facilities which have a delivery
21 capacity of greater than 15,000 decatherms a day.

22 As I understand it, the intent of Order No. 720
23 is to gather information with regard to end-use facilities
24 of a certain size. The first point here is that these end-
25 use facilities typically are going to be served through

1
2

1 pooled accounts, and there is no price formation downstream
2 of the city-gate.

3 Turning to the next page, this describes the
4 pooling of the accounts by which these end-use facilities of
5 a certain size would receive their gas supplies.

6 Participants in our transportation program are
7 assigned a customer account for nominations and scheduling
8 purposes.

9 A single customer account can represent one or
10 numerous end-use facilities with varying types of end uses.

11 And balancing of scheduled volumes and deliveries
12 by customer account is monthly, not daily. I think that is
13 the limitation that produces the result that the information
14 that the Commission seeks to obtain with regard to these
15 end-use facilities of a certain size is not really available
16 from the system operators of the LDCs.

17 Turning to the next slide over, over 90 percent
18 of those 10,000 customer accounts are aggregated into
19 Contracted Marketer accounts. Those are pools. A Marketer
20 acts to pool the accounts of individual customers. And over
21 90 percent of our 1,000 customers are served through a
22 Marketer Pool.

23 The marketer assumes the monthly gas delivery and
24 balancing requirements for their group or pool of end-use
25 customers.

1
2

1 Marketers nominate to the pool account, not to
2 specific end-use customers, not to specific end-use
3 facilities. The marketers are not required to nominate any
4 quantity on a daily basis, and the nominations could vary
5 from zero to any amount and therefore bear no real relation
6 to expected consumption or actual consumption at a facility
7 on any given day or period of days.

8 I will note that for the PG&E System I believe
9 there is a nomination to an end-use facility but the
10 function of the nomination is not any estimate of actual
11 consumption. It is a numerical convention to allow PG&E's
12 scheduling system to operate. The numbers that are posted
13 to end-use facilities by marketers can be arbitrarily
14 assigned.

15 For example, a marketer may have the ability to
16 nominate 100 units. It may nominate 10 units to one
17 facility, 20 to another, 30 to a third, and the balance of
18 40 to a fourth, and none to the other six. It really bears
19 no relation to the actual consumption or expected
20 consumption at the facility.

21 And again for SDG&E/SoCalGas we do not even have
22 nomination down at the individual-facility level.

23 The conclusion is that requiring of posting of
24 scheduled volumes to end-use delivery points on the
25 California LDCs' systems will not facilitate price

1
2

1 transparency in markets for the sale or transportation of
2 physical natural gas in interstate commerce. That is
3 because, again, on the SDG&E/SoCalGas Systems we don't even
4 have nominations to end-use delivery points, and the
5 nominations on the PG&E system are arbitrary and do not bear
6 any direct relation to actual or expected consumption.

7 The next slide is a Nominations Model. I'll just
8 discuss it briefly. We show at the top the two sources of
9 gas supply into the system, either supplies from interstate
10 pipelines or approximately 7 percent of the supply is from
11 California producers.

12 On our system those come through a Receipt Point
13 Access Contract. That's the RPAC. From there they can
14 typically go one of three places: Customer Pool, city-gate
15 Pool, or Storage. Or they can go directly to the off system
16 delivery, OSD, which currently again is only PG&E for our
17 system.

18 The last three slides are answers to the
19 questions posed by Staff as part of the notice of this
20 technical conference.

21 The first question is: Is there some rule of
22 thumb to identify points at which advance notice of receipts
23 and deliveries is required for operational purposes?

24 I think in looking at these questions I
25 appreciate that you recognize the limitation on the validity

1
2

1 of the information that is typically available to LDCs on
2 scheduling to end-use facilities, and these questions ask,
3 don't you have some operational need to have this
4 information? Generally the answer is: No.

5 So this specific question: Is there some rule of
6 thumb to identify points at which advance notice of receipts
7 or deliveries is required for operational purposes?

8 The answer is: Not for deliveries on the
9 SDG&E/SoCalGas and PG&E Systems. We don't have an
10 operational need for advance notice of deliveries to end-use
11 locations for individual entities in order to plan our
12 system operations. We receive information from the
13 interconnecting pipelines, and we have our own information
14 regarding historical consumption patterns, weather
15 information. We may have information on specific planned
16 outages, and information from the California ISO, and that
17 is what we use to plan daily system operations.

18 The second question: How do companies without
19 scheduling information address the risk of demand
20 volatility for large-scale consumers receiving unbundled
21 service?

22 Our response is that our systems are designed and
23 built to criteria defined by our State Commission, and we
24 recover the costs of those facilities in rates paid by our
25 customers, including transportation rates, paid by, among

1
2

1 others, the 110 or so customers of the size that Order
2 No. 720 inquires about.

3 The systems are designed to manage hourly and
4 daily flexibility--I'm sorry, hourly and daily volatility in
5 demand primarily through the use of storage. And this is in
6 contrast to interstate pipeline systems which are designed
7 to move gas from point A to point B on a uniform average
8 daily basis.

9 Your third question was: How do pipelines
10 reconcile nominations with actual flows at pooled points?

11 For our city-gate we reconcile by each Nomination
12 Cycle. Your nominations have got to be confirmed or else
13 they'll be cut.

14 But past the city-gate, this is done on a monthly
15 basis. Again I refer back to the point I emphasized
16 earlier, and that is: balancing is monthly, and it is done
17 at the pool level. It is not done at the individual
18 facility level, and it is not done on a daily basis.
19 Therefore, we have no need for scheduling down to the end-
20 use delivery point on a daily basis, and we don't have that
21 information available.

22 That concludes my initial remarks. Thank you.

23 MS. COCHRANE: Thank you very much.

24 Mr. Young?

25 MR. YOUNG: Good morning. I am Robert Young. I

1
2

1 am Director of Scheduling for Energy Transfer, and I wanted
2 to go through some of the questions you had.

3 We also had a proposal on some design capacity
4 that I wanted to get to. But before I do that, it seems
5 like the common theme that everybody has been talking about
6 so far is Mainline Receipt Points are what we need. Because
7 there's a lot of gathering systems out there who have small
8 wellheads. You have city-gate, LDCs, you have small
9 deliveries downstream. But all of that gas seems to be
10 captured at the Mainline Receipt Point into an interstate or
11 into an intrastate. So, where you could have duplicative
12 data if you go back to the wellhead or to the city-gate. So
13 capturing that information at the Mainline Receipt Point
14 seems to be something that I've seen or heard so far.

15 Going through the questions on is there some rule
16 of thumb, I concur with Mr. Ellis's comments. What our
17 response would be is: It depends.

18 Some pipelines actually do have nominations at a
19 wellhead. I think very few, if any, LDCs have nominations
20 at their ultimate delivery points. But it seems like
21 everybody does aggregate at a Mainline Receipt Point. So
22 they would--some pipelines, if they have wellhead flow,
23 sometimes just manage the tailgate into the downstream
24 pipeline. That's where the nominations come.

25 Then there's either a monthly, sometimes daily

1
2

1 process that those gatherers would have with their
2 customers.

3 How do companies without scheduling information
4 address the risk of demand volatility?

5 Most of the times systems are designed to take
6 that into account, but for the most part the Gas Control
7 shop will look at linepack. If we've got deliveries to a
8 bunch of city-gates, there will be nominations to the
9 virtual meters, the pool meters, whatever you want to call
10 them, the point where all the gas is supposed to be
11 delivered to that market point.

12 There might be hundreds of meters that come in
13 that we might have SCADA on, we might not have SCADA on, but
14 a gas controller will know a scheduled number that he's
15 expected to see for an area for that day.

16 They'll look at that number. They'll look at
17 their SCADA screens. You'll see overpulls or underpulls,
18 and you'll see linepack go up and down, and that's where the
19 gas controllers can manage the pipeline, whether they have
20 storage, if there's nomination cuts in subsequent cycles, or
21 whatever we need to do.

22 But for the most part, the gas controller will
23 look at it and he'll tell you on a 5:00 p.m. in San Antonio
24 in the summertime, 5 o'clock your linepack is going to go
25 down because everybody comes home, turns on their air

1
2

1 conditioners so the LDCs pulling all the gas off the pipe.
2 But they manage that throughout the day, and that's where
3 they have the 24-hour nom. They'll pack the line, try to
4 stay within the parameters and everything kind of works.

5 It's as much an art form as it is a science.

6 Then how do pipelines reconcile nominations with
7 actual flows at pool points?

8 Again, a lot of times that is a monthly process.
9 There are a lot of virtual pool points, and the reason
10 there's virtual points is, when you have shippers and
11 customers who you might be delivering to hundreds of points,
12 the simple fact of nominating individually to those points
13 is not manageable on a daily basis.

14 So if you'll have a customer who is scheduling
15 gas to those hundred points, they just give you a nom for
16 one, we'll actually get measurement data at the end of the
17 month, sometimes daily, for those points but you allocate
18 that nomination back to those points, or you aggregate those
19 points back up to that nomination.

20 So again it is more of a commercial tool, and it
21 is not really necessary to have people nominate to
22 downstream delivery points, certainly at LDC delivery
23 points, and certainly from gathering systems where all that
24 gas is brought in by one party. There's no reason to have
25 to have a nomination we feel at this point.

1
2

1 Then finally, one of the things we have struggled
2 with a little bit is in terms of the posting requirement is
3 the definition of "design capacity."

4 Part of the issue is, when we say "design
5 capacity of 15,000," I'm not an engineer but I've talked to
6 lots of engineers, and a rule of thumb could be:

7 A 4-inch meter run could actually flow 16 million
8 a day. If you look at most of your 4-inch meter runs at the
9 wellhead, they're not going to flow more than a couple
10 million a day. So in that case, if we use that as the
11 design capacity, we're going to have postings of a 16-
12 million capacity with throughput of 2 to 3 million, which
13 will show available capacity of a lot more, which is really
14 not the case.

15 A proposal that we have--this is not necessarily
16 in regulatory text, but just to get the idea--we would like
17 to change it to say:

18 A major non-interstate pipeline must post at all
19 nominated, receipt, and delivery points with 10-day
20 nonconsecutive average peak flow of 15,000 MMBtu per day
21 during the prior calendar year, to be updated every April
22 1st. A such points the pipeline will post such 10-day
23 nonconsecutive average peak flow as capacity at the point
24 rather than design capacity, and available capacity at the
25 point will be determined based upon capacity minus scheduled

1
2

1 volume.

2 What that does it, if you take an average flow at
3 metered, which is realistic of what's going to be produced,
4 if you define that as the "capacity," you'll have a better
5 feel for what physically comes along, what the real capacity
6 is, rather than an engineering capacity which is always
7 going to be a lot higher than what a meter will physically
8 do on normal days.

9 MS. COCHRANE: Could you just repeat that again?
10 You appear to have a definition, so I just want to make sure
11 we understand.

12 MR. YOUNG: Okay. A major noninterstate
13 pipeline must post at all nominated receipt and delivery
14 points--that's just every point we schedule on, and that
15 would be in cases where we have pool meters we would post at
16 the pool meter level rather than the individual points
17 behind it--with 10-day nonconsecutive average peak flow of
18 15,000 MMBtu per day during prior calendar year.

19 What that means is, go back a year. Look at all
20 the points. See--take the top 10 days for the last year.
21 If the average of those is more than 15,000 a day, post
22 that. And we had a timing of posting that yearly, and we
23 could update that as necessary.

24 And at those points, at such points pipeline will
25 post such 10-day nonconsecutive average peak flow as

1
2

1 capacity. So rather than a design capacity, that would
2 become your capacity. You would compare that to your
3 scheduled record that are nominated every day.

4 The available capacity would then be the
5 difference between the two. And when you do that, based on
6 the diagrams that we've looked at, especially if you look at
7 Mainline Receipt Points in the diagram that was presented
8 before, you have all these wells upstream of a plant. Most
9 of those, it could be 4-inch meter runs, but they probably
10 aren't going to flow more than 15,000 a day.

11 But at the Mainline Point where it comes into the
12 system, it certainly will be 15,000 a day. And if it's not,
13 it's just a very small plant.

14 You post the volume at that point, and then you
15 compare that to your schedule everyday. And that is your
16 capacity. So in that case, you are capturing the gas coming
17 into the market at that one receipt point into a inter- or
18 an intrastate point, rather than multiple points upstream.

19 So I would envision, based on the example, rather
20 than having all the gathering points, but 100 gathering
21 points with a design capacity of 16,000 a day flowing from
22 100 to 5 million a day, you would have one point that could
23 be 100 million a day with a design capacity and scheduled at
24 that point, because that's where most people do their
25 scheduling anyway.

1
2

1 And even if people schedule at the wellhead,
2 there is always scheduling at some type of Mainline Receipt
3 Point, whether it be a virtual or an actual point.

4 And I think that covers everything.

5 MR. NOVAK: Excuse me, I have a process question.
6 I didn't know whether we would be going through question by
7 question, or what you would like to do at this point,
8 because I have my rule of thumb also. Would you like that
9 now? Or do you want to go through--

10 MS. COCHRANE: Sure, because I was going to ask
11 you how you were going to get this into the record. But,
12 yes, please go ahead.

13 MR. NOVAK: Okay. On the Rule of Thumb for LDCs,
14 this question really has to be broken into two questions:
15 One for receipts and one for deliveries.

16 Receipt information is far more critical because
17 the operational assumption is that deliveries will be made
18 no matter what quantity of gas is received into the system.
19 The deliveries will be based upon customer demand and in
20 nearly all cases not upon what the LDC receives into its
21 system.

22 Pipeline no-notice service, or in some cases on-
23 system assets--for example, line pack and in a few cases
24 storage--are used to supplement or balance the difference
25 between what is received and what is delivered--which is

1
2

1 the market demand. This is essentially how LDCs "back stop"
2 the system.

3 Keeping in mind that (1) most gas is received in
4 LDC systems at the city-gate, and (2) that both LDCs and
5 marketers serving LDC customers nominate gas on pipelines,
6 LDCs officially learn how much gas is being received for the
7 next gas day at 4:30 p.m. Central Time for the NAESB
8 Standard.

9 Some LDCs with their own scheduling systems may
10 have some advanced notice depending upon their own
11 nomination timelines, and LDCs with or without scheduling
12 systems--to the extent that they're actively engaged in the
13 pipeline confirmation process--can improve their advance
14 notice also.

15 Of course all of this relevant information
16 regarding the receipts into the LDC systems at the city-gate
17 interconnections with interstate pipelines are already
18 available from the interstate pipelines.

19 Depending upon the LDC system configuration,
20 advance notice at some city-gate receipt points may be more
21 critical than others. And I think that Vonda started to
22 touch on this in her presentation. You look at the size of
23 different markets, whether they're contiguous,
24 noncontiguous, our terminology is "load pockets." You need
25 to look at the number of options. Advance notice of sole

1
2

1 sources into load pockets is probably to be of more critical
2 importance.

3 Scheduling of deliveries is generally of much
4 less importance because the LDC systems are designed to
5 distribute the receipts that flow.

6 The more critical problem is making sure that the
7 right amount of gas shows up at the receipt points. LDCs
8 project load for their bundled customers and in particular
9 for customer choice programs for unbundled customers.

10 Suppliers often receive instructions prior to the
11 nomination deadline on what quantity should be delivered to
12 the LDC. These projections are based upon historical load
13 patterns and weather forecasts. It is not really a matter
14 of looking at market pricing to determine whether gas should
15 be received and whether the customer delivery should be
16 made.

17 Larger industrial and commercial customers
18 sometimes have more latitude in determining what quantity of
19 gas is necessary to serve their load.

20 In some cases this flexibility may be associated
21 with a service that limits the customer balancing rights
22 and/or necessitates a point-to-point nomination--a receipt
23 to a delivery point.

24 Nevertheless, in most cases an LDCs do not
25 require a nomination to a delivery point because (1) the

1
2

1 customer's physical location is not going to change; and (2)
2 the customers may be pooled for nomination purposes with
3 other customers that are served by the same supplier.

4 In this latter case, the LDC is more concerned
5 that the total pooled receipts match the total pooled
6 deliveries and not with any particular transmission path.
7 Please keep in mind that if the LDC doesn't require a
8 nomination to the delivery point, it doesn't have the
9 delivery point scheduling information.

10 On the issue of addressing the risk of demand
11 volatility from large-scale consumers receiving unbundled
12 service, generally this is done through service and rate
13 design.

14 Balancing calculations can be performed on a
15 daily or a month level. In either case, it's a matter of
16 allocating the costs of assets used to balance to those that
17 require balancing. This is a critical matter in the state
18 regulatory environment. An interrelated concern is to avoid
19 having one group of customers subsidizing another.

20 Note that for customer pools, balancing is
21 usually at the pool level--in other words, total receipts to
22 total deliveries rather than matching particular receipts
23 to particular customer deliveries.

24 Finally, many utilities use SCADA systems to
25 monitor system flows and have OFO authority to tighten

1
2

1 transportation service flexibility if it becomes necessary.

2 Lastly, on reconciling the actual flows at pooled
3 points, many LDCs incorporate pooling into their scheduling
4 rules. This can be done for receipts--at city-gates or for
5 On-System Production--or deliveries--groups of customers.
6 Pools can be organized geographically, by service
7 characteristics, and/or at the supplier's discretion. It is
8 really a territory-by-territory determination.

9 For most LDCs, the reconciliation is a monthly
10 accounting calculation but depending upon the service design
11 can be a daily calculation.

12 Keep in mind that service designs and changes to
13 service designs need to be approved by state commissions.
14 Whether a daily or monthly reconciliation, flow differences
15 can be balanced with physical assets, cased out, or carried
16 forward to a subsequent day or month.

17 Note that even under a monthly reconciliation,
18 LDCs may monitor daily activity to make sure that there's a
19 relative balance within a tolerance range.

20 Thank you, very much.

21 MS. COCHRANE: I just wanted to clarify for
22 Mr. Ellis why I asked that question about city-gate. In
23 your Rehearing Request you suggest that posting could be at
24 the interconnections with the interstate or at the city-
25 gate, and I just wanted to clarify that that means two

1
2

1 different things. That your city-gate is not at the
2 interconnection with the pipeline.

3 MR. ELLIS: That is correct. They are two
4 different places. And I think for SoCal Gas the more
5 correct statement would be On-System Receipts versus
6 deliveries to Storage. And for PG&E's system, they have a
7 number they can post at the city-gate. For ours, let me
8 just say it could be traded, the amounts scheduled to a
9 city-gate can be traded, can be scheduled in and out, and I
10 think the more accurate measure would be On-System
11 Receipts.

12 MR. REICH: Ms. Shahan, in your hearing request
13 you say Nicor has 400 meters that meets the 15,000 limit,
14 but you only schedule about a dozen?

15 MS. SHAHAN: Yes. And actually I can clarify
16 that even more. Those entities are not scheduled to their
17 delivery point meters. They are restricted in scheduling to
18 specific receipt points.

19 So they would not be able to use our CDP with
20 Natural because those entities--we have some very large
21 refineries in our service area, and then we have some
22 electric generators, and because of their load, and they are
23 close to certain pipelines, they are required to bring it in
24 off of that pipeline and schedule to that receipt point into
25 our system.

1
2

1 But basically it's the receipt point. It's not
2 their delivery point.

3 MR. REICH: Just to clarify, so their
4 activity--if they have volatility in their demand, that
5 would show up in a nomination on the pipeline?

6 MS. SHAHAN: Well, no, we do balancing for them.
7 So they have nominated it on the pipe, the pipe is confirmed
8 and scheduled a certain amount. If something happens during
9 the middle of the day or the night and they've changed in a
10 later nom cycle on the pipe, we don't have a later nom
11 cycle. They're just out of balance and we will help them
12 with our storage. They have storage rights under their
13 contract.

14 MR. REICH: So for Natural--you said Natural was
15 your--

16 MS. SHAHAN: It's one of them.

17 MR. REICH: --your main pipeline--

18 MS. SHAHAN: Um-hmm.

19 MR. REICH: So if you have one of these
20 facilities that can only get gas off of Natural, what does
21 that look like? What does, you know, one day where they
22 have high demand versus one day that they have low demand
23 look like to Natural versus what it looks like to you in
24 terms of planning?

25 MS. SHAHAN: Well, actually they aren't on

1
2

1 Natural, I will say that. They are on some of the others.
2 We are on seven interconnects. And they--if they have
3 changed their mid-day or late nom, we still have them
4 scheduled for their morning nom. And again, whatever they
5 bring in and the pipe has proved, or confirmed, they get to
6 play with that difference with their storage.

7 MR. REICH: And are these--these are
8 transportation, all transportation customers?

9 MS. SHAHAN: Yes.

10 MR. REICH: So you're just, you're providing
11 transportation service but also balancing service?

12 MS. SHAHAN: Yes. All our transportation
13 customers do have a certain amount of storage rights under
14 our Illinois Tariff.

15 MR. ELLIS: That's the same situation for our
16 system, too.

17 MR. REICH: You anticipated my next question.

18 Also, Ms. Shahan, in your--in the Rehearing
19 Request you talked about your eight storage facilities. Can
20 you talk a little about how those are scheduled, or planned
21 for on a daily basis?

22 MS. SHAHAN: Again there's the two different
23 worlds at Nicor. There's the SCADA control room that's
24 watching the pressure and making sure everything is
25 copacetic, working. That is really behind the scenes of

1
2

1 what transportation customers are doing and what they're
2 scheduling.

3 They are--if it's summertime and they want to
4 fill their storage, they just nominate to storage. They
5 don't have rights in different fields. They're scattered
6 around our service area. And they nominate--and it doesn't
7 really matter what pipe they bring it in off of; they're
8 nominating to virtual storage, and we make sure it gets
9 where it needs to go.

10 MR. REICH: So it's an unbundled storage service
11 where these customers, their gas is in storage as opposed
12 to, or in addition to buying gas from you, if necessary--

13 MS. SHAHAN: Correct.

14 MR. REICH: And with SoCal?

15 MR. ELLIS: Same situation.

16 MR. REICH: Chris?

17 MR. PETERSON: The model that seems to occur on
18 many of these systems is large-volume receipts are scheduled
19 either by you or in some cases maybe by others into
20 substantial city-gate receipt points. And then things vary
21 from there in terms of the latitude that your customers have
22 to then schedule that gas on non-major interstates of
23 different sizes.

24 But generally what would help us understand is
25 that--I mean, some of you have large--you have generated

1
2

1 assets on your systems. They can consume 85 million to 170
2 million a day at typical 7000 heat rate combined cycle
3 plants. These loads can change quickly depending on weather
4 conditions.

5 So if you're just scheduling at the pool level
6 and you're truing up at the end-use level on a monthly
7 basis, how are you managing congestion on your system? How
8 do you make sure that the pipeline system integrity isn't
9 being violated?

10 Because there's this disconnect in that, on the
11 one hand at certain points things are happening daily,
12 there's SCADA, you may even be looking at things at one
13 level hourly, maybe even five-minute intervals, or whatever,
14 yet on the end-use side you're only looking at deliveries
15 maybe on a monthly basis.

16 So how do you reconcile this? How do you make
17 sure how you manage congestion? How do you make sure
18 customers are getting what they're entitled to commercially
19 and in their contracts? That would help us understand sort
20 of the commercial and operational challenges you might have
21 in comporting with different ways we could go with this
22 rule.

23 MR. ELLIS: For SoCalGas/SDG&E, as I heard the
24 question: What do you do when things start to get out of
25 balance? What kinds of things can you do to manage these

1
2

1 situations?

2 And, you know, we have operational flow order
3 authority if the situation--if the system situations require
4 it. And in that case, balancing is daily.

5 For SoCalGas/SDG&E currently, the OFOs are for
6 pack conditions only. We no longer call OFOs for draft
7 conditions. For pack conditions, the typical response to a
8 pack OFO would be to immediately stop scheduling.

9 But the general question you asked, how is the
10 volatility managed other than monthly, it's managed daily on
11 an OFO basis if the conditions require it. And in that case
12 balancing is daily.

13 MR. PETERSON: And the OFOs you might apply,
14 would those be system wide? Are the customer-specific?
15 That varies on interstate natural gas pipelines too
16 depending on who is leaning on the system, where it is. How
17 does that work?

18 MR. ELLIS: I believe ours is system wide. That
19 is subject to check.

20 MR. REICH: Can I follow up?

21 MS. COCHRANE: Mike would like to--

22 MR. NOVAK: Yes, I think it is also a case-
23 specific situation. And Bridget started to touch on the
24 operating world versus the accounting world.

25 In the operating world, you are probably going to

1
2

1 have a communication from the operator of the electric
2 facility to the gas control room, hey, we're going to be on
3 in a few hours. It has nothing to do transactionally; it's
4 just the load is coming on. So that is going to tell the
5 gas operator, start packing the system.

6 The nominations will come in. They'll be
7 balanced. I mean, again it's a service design and probably
8 location of facility type of situation. The OFO authority
9 can come into play. But there won't necessarily be a one
10 common rule that fits every single situation where this is
11 going to come into play.

12 MR. YOUNG: One thing, in terms of the process a
13 lot of times you'll have pipelines--you know, pipelines will
14 have their gas control center. You'll have the LDCs who
15 have their gas control centers. The mainline delivery
16 points often have balancing agreements between the pipe and
17 the LDC.

18 So there's a process at the beginning of the
19 month to estimate how much gas you're going to need. So the
20 LDC customers will come in and say this is how much I'm
21 going to need this month. They'll secure gas. They'll
22 either buy it from shippers, have their own transport
23 agreements on the pipelines, and they'll nominate to that
24 mainline delivery point.

25 Then as things happen, you know, that estimate

1
2

1 assumes they're going to be able to cover everything with
2 their line pack. They've got enough for the day to cover
3 everything.

4 If there are overpools for some reason, the
5 pipeline is going to see that there's gas being overpooled.
6 There's communication between the control centers every day.
7 If something has to happen, there's communication. The gas
8 controller on the pipeline will say: What's going on?
9 You're supposed to take 50 million and you're taking 80
10 million.

11 Then the response could be: Well, we just got a
12 problem here. Can you help us out? Or we're going to get
13 back down on rate. Or there needs to be a new schedule at
14 that mainline delivery point to bring more gas in because
15 the pipeline has to manage that same type of thing with all
16 their delivery points.

17 So, you know, without getting into all the orders
18 and the postings on a daily basis, that's just part of the
19 gas controller's job to know. But there's a lot of work
20 that gets done into that schedule director at the beginning
21 of the month. So they're not just scheduling a number and
22 letting it flow; they're doing some analysis and estimates
23 of what they're going to need for the month, and they're
24 usually pretty close.

25 And then on a daily basis, the gas control

1
2

1 centers work with each other to make that happen.

2 MR. PETERSON: If I could follow up on that, so I
3 guess one thing that would be helpful for us to know more
4 about, too, is if your main concern is that receipts and
5 deliveries at the city-gate pooling points, or main entries
6 in your system match on a daily basis, then how do you
7 allocate volumes of gas to your large customers that sit
8 behind your gates?

9 How does that work? If it's not a daily nom
10 process, how do you effectuate that commercially? And I
11 think what you were saying is some of this is, you look--is
12 some of this done on a monthly basis where, okay, it's not
13 done daily but a generator may say, hey, I anticipate
14 needing 50 million a day on average. They let you know
15 that. And then you set up your system that way? Or how
16 does that work?

17 MR. YOUNG: I think one of the reasons there is
18 not a daily allocation is because most of--and I'll let you
19 guys correct me where I'm wrong--but on the LDCs, most of
20 those delivery points serve a customer. So you don't have
21 multiple allocations at an ultimate delivery point.

22 So whatever flows to that ultimate delivery is
23 allocated to a customer. So they'll have a pool of all of
24 their gas. So if they have 100 meters, those 100 meters all
25 aggregate to one customer. So the customer then can

1
2

1 schedule that one number, and the LDC's responsibility is
2 just to make sure the deliveries get there.

3 But then there's a post-month allocation, if you
4 will, saying here's the measurement, here's the volume that
5 flowed at each of those points. You sum it up to that
6 scheduled record level, and that is your imbalance, if you
7 will.

8 MS. SHAHAN: And I'll just add that, you know,
9 these customers on Nicor's system have contractual
10 limitations. They have MDQs that they're supposed to stay
11 within. And if they haven't, then they will either have an
12 authorized overrun, or an unauthorized overrun, but they
13 again are nominating to their pools.

14 They may have one meter that could be a
15 transportation customer that is just a refinery and he has
16 one meter. Or it could be a supplier/marketer type of
17 transportation customer that has a thousand customers behind
18 him. And all those meters are on his contract, and that is
19 his responsibility to figure out--he's going to get charged,
20 and then he's going to have to figure out with his customers
21 what deal he has negotiated for them for their supply.

22 So it is still an end-of-the-month issue. And as
23 far as every day, we are looking at there's lots of
24 forecasting that goes on. Constant forecasting and revising
25 the forecasts because of the weather as much as any other

1
2

1 volatility. But market demand can also, and supply
2 operations or force majeure can affect those too.

3 But the control room has plans and is watching
4 not just daily, but speaking multiple times during the day
5 to other control rooms just to make sure everything is
6 working and going all right and they don't see any issues
7 coming from upstream toward us.

8 So it is an art, and it is a constant
9 communication.

10 MR. YOUNG: I mean, as an example, if you
11 had--you know, I'm the pipeline. I'm delivering to an LDC.
12 It could be either a nomination at our interconnect point of
13 100 million. Then that's there for the month.

14 Then one day all of a sudden 140 million is being
15 pulled off our system because they need some gas. Well the
16 first thing I am going to see as a gas controller is we're
17 going to call and say, what's going on?

18 If it's an anomaly, they say, well, the
19 temperature's just raised real high, there's some anomalies
20 today, you know, can we go out-of-balance for the day?

21 Well then my response could be: Sure, but you
22 need to nominate more for tomorrow because I can't prop that
23 up. And that's where the nomination process at the mainline
24 delivery point would happen. They would identify the people
25 who were overpooling. They would have secure transportation

1
2

1 on our pipes so that tomorrow that nomination could be 140
2 to meet that pool, or maybe 160 to meet the pull of 140 so
3 that I can get paid back for the gas they pulled yesterday.

4 So again, it is more of an art with some science
5 mixed in.

6 MR. NOVAK: Even for pools from customer-choice
7 programs where we may be given a different quantity
8 instruction every single day of the month, obviously the
9 meters you might have with 20,000 customers in a particular
10 supplier's pool, we aren't doing a daily comparison of how
11 much they delivered to how much the customers used on that
12 day. We simply sum up all the customer consumptions, then
13 we sum up all the receipts that should have in at the
14 quantities on the days that we wanted, and then compare the
15 two numbers.

16 And then any balancing will take place not at the
17 customer level but at the supplier level between the
18 supplier and the utility.

19 MR. PETERSON: If I could follow up with
20 comments, Mr. Novak and Mr. Young, you both just made then,
21 it seems to me in the comments that have been made there may
22 be challenges in terms of disclosing on a daily basis
23 information that might be customer level on networks for
24 your companies or your members, but what I'm hearing though
25 is ultimately on a monthly basis because of invoicing,

1
2

1 because of billing, you do know ex poste at least how much
2 you are delivering to your customers in situations where you
3 don't know day to day, but because of the monthly billing
4 cycle you do ultimately know that. And that information is
5 available to you.

6 So on a daily basis you have information
7 available at some SCADA-metered locations, major receipt
8 points, maybe even some major delivery points, but in
9 addition you do know this information at--or you arrive at
10 information through allocation procedures or other true-ups
11 and balancing adjustments for the end of the month for your
12 customers. Is that correct?

13 MR. NOVAK: That's correct.

14 MS. SHAHAN: I just have to clarify the question.
15 If you say "this information," there's the scheduled world,
16 and there's the actual flow world.

17 MR. PETERSON: Right.

18 MS. SHAHAN: So it's what are you asking for.
19 What actually flowed, we definitely know by the end of the
20 month, and maybe 15 days later by the time the bill gets
21 out--

22 MR. PETERSON: Right.

23 MS. SHAHAN: --what we're charging end-users for.
24 But--or what their suppliers are charging, because we're
25 reading the meters, are charging the end-users for.

1
2

1 But the scheduled, again, is these virtual
2 points. And part of the clarification Nicor asked for is,
3 if you want this information of what is scheduled into our
4 system to pools and points, please realize there is no
5 location information. There is no available capacity
6 information. There is no design capacity information
7 because they are paper.

8 MR. NOVAK: Let me amend my answer just a little.
9 It depends upon the meter at the location. For the large
10 customer, we're probably going to have daily measurement and
11 are probably going to know more quickly, and are probably
12 going to know an exact number that they used.

13 When we're talking about a residential customer
14 where I'm reading it once a month on a billing cycle, the
15 best I can tell you is what I think they used.

16 MR. YOUNG: And so I would say you do have
17 measurement data at the points, but to move that back to,
18 and compare it to the scheduled data, it depends on how
19 different pipelines do their allocation process at the end
20 of the month.

21 Some people will allocate to the measurement
22 meter so that you will have the month scheduled and
23 measured. In other cases those measurement meters are
24 actually grouped. So the measurement is at a group virtual
25 meter and you apply that to the nomination that was done at

1
2

1 that same virtual group meter.

2 So you would have to put it together or break it
3 apart if you wanted to go one-to-one, but not all--either
4 gathering systems or LDCs would have a one-to-one
5 relationship at the end of the month. They would have
6 measurement at the end of the month.

7 MR. PETERSON: I've got one last follow-on for
8 you, Mr. Young.

9 All of the companies we purport to cover under
10 this rule have some significance in terms of the size. We
11 increase the annual volume commitment by a factor of five,
12 going from the NOPR to the Final Rule, considering burden
13 issues and some of the reporting things that you all are
14 relating to us today.

15
16
17
18
19
20
21
22
23
24
25

1
2

1 But even within the continuum of the possible
2 market participants that would be covered by this Rule,
3 there could be a lot of variety in terms of information that
4 does exist already, currently, for example, PG&E and SoCal,
5 they have the Pipe Ranger and onboard systems, somewhat
6 unique for LDCs to actually have something, you know,
7 somewhat like what interstate natural gas pipelines offer.

8 I suspect there are other companies, maybe TPA
9 members, that are very large companies, many of which might
10 be much larger even than standard interstate natural gas
11 pipelines, that may have a richness and robustness in terms
12 of the amount of information they collate each day already,
13 and how they solve their networks each day.

14 And there are these -- and there may be other
15 systems that may be smaller, that use the city gate model
16 where they are just kind of measuring what is coming in, to
17 like a handful of major city gate points, and then from
18 there, it's kind of a pool, and then from there, there may
19 be different strategies in terms of how you allocate that.

20 Can you speak to, you know, representing TPA and
21 the different companies you account for, can you give us
22 some insight as to the complexity of information, what
23 exists now, that's already being collated, how that
24 information is used, and how that might work?

25 MR. YOUNG: Well, there is a variety, and when

1
2

1 you talk -- you know, you hear the word, "pools" or
2 "aggregation points," and I think the issue that most people
3 have, is the level of detail at either the initial upstream
4 wellhead point, or the final downstream delivery point.

5 The one consistent point, I think, that
6 everybody probably has, is a mainline receipt point or a
7 mainline receipt or delivery virtual point. And gas is
8 scheduled at that point.

9 Even pipelines who schedule at the wellhead, they
10 will also schedule at the delivery point, into an
11 interconnect at a pipeline, an intra or interstate pipeline.

12 So the consistency, in my mind, would be at that
13 point, so you could have kind of common ground for
14 everybody, and then you don't have the burden of LDCs having
15 to figure out, well, how do I get all these thousands of
16 meters to compare to a scheduled record, when I don't have
17 it?

18 I think that's the issue that most of the
19 pipeline companies have. You know, from an energy transfer
20 standpoint, we've got receipt points coming into our pipe,
21 people nominate on those, and if they are more than 15
22 million a day, those will be posted.

23 But if we have a point where we're aggregating
24 hundreds of meters, we have one set of pipelines where gas
25 comes in, it's purchased; it's all at a -- there's really

1
2

1 not a nom, because we just know what we do, estimates of
2 what we think is going to be out there, but we don't really
3 nominate this gas that we're buying.

4 So there's really not a nomination that we can
5 look to. We'd have to create that at the end of the month,
6 or daily, for reporting purposes, but we do have that data
7 downstream at the mainline receipt points and the delivery
8 points, where we can provide that data.

9 And it's 1:1, if you will. There might be some
10 cases where you have to group, when you do the reporting, if
11 you have hundreds of those points, and we schedule at the
12 virtual point, then the design capacity or the capacity at
13 that virtual point, might have to be the sum of those meters
14 that were upstream of that.

15 But I think that could be a designation that each
16 of the companies could make, and some people could have the
17 upstream, other people wouldn't, so, you know, some
18 companies pool one way; others pool another. But the
19 consistency is that scheduled virtual point and how do we
20 report capacity at that point?

21 MR. ELLIS: I wonder if I could speak to that
22 question? As I heard, Mr. Peterson, you're asking, what
23 information is available.

24 I think I would begin by saying that we look at
25 what information is of value, that you've got posted

1
2

1 information at a level that we believe is of value.

2 If you turn to Slide 4 in the presentation
3 materials, that's the map that shows the receipt point
4 zones. You go on our website today, you'll see, for each of
5 these receipt point zones, with the amount of capacity
6 available, you can see how much is being used, and,
7 therefore, how much is available at each of these locations
8 on a receipt point basis.

9 That's currently available. We think that's the
10 level of information that is important to know, what is the
11 capacity that you use to bring supplies into our system.

12 And to answer Ms. Cochrane's question again, we
13 think the three levels are: What's on-system; what's going
14 to storage; and what's going off-system.

15 The on-system, again, is broken down at each of
16 these five zones, to tell anyone interested, what is
17 available at any time that they're looking.

18 And I think this is important with reference to
19 the explanations stated at Paragraph 50 of Order No. 720, in
20 which the Commission is saying, why are you looking for this
21 information; what are you going to do with it?

22 The example that's given at the end, for
23 example, in overseeing markets, the Commission routinely
24 checks for unused interstate natural gas pipeline capacity
25 between geographically distinct markets with substantially

1
2

1 different prices, as a sign that flows may be managed to
2 manipulate prices.

3 What we have available today, is capacity, the
4 amount of capacity that's available to bring supplies into
5 our system. We don't think there's any addition to
6 transparency that could be found, if you did have -- if we
7 did have, if you did have access to demand down to the
8 individual facility level.

9 The relevant inquiry is, what can be brought into
10 our system, how much is going into storage, how much is
11 going back off the system; that's the level at which we
12 think the information is valuable for the purposes you
13 stated.

14 MS. COCHRANE: For clarification on this, is this
15 available to anyone?

16 MR. ELLIS: Yes.

17 MS. COCHRANE: You mentioned that we have the
18 customer password on your website, and I just wanted to
19 clarify what's publicly available to anyone looking on your
20 website.

21 MR. ELLIS: It's the information I just stated;
22 it is publicly available. Anybody who wants to see what's
23 available in a particular receipt point, location, can do
24 so.

25 MR. REICH: Just to follow up with you, Mr.

1
2

1 Young, you talk a lot -- you've been using the terms,
2 "mainline receipt point, mainline delivery point."

3 From a regulatory perspective, is there some way
4 -- can you suggest a way to define the term, "mainline,"
5 that you -- as a starting point?

6 MR. YOUNG: I think there's a -- we looked at --
7 there's a reg. I don't know the exact area, but it's
8 defined in the regs, and that was, you know, at the tailgate
9 of a gathering system, processing plant, you know, anywhere
10 at the -- where gas comes in from a grouped set of wellheads
11 and delivers into a point, and then, you know, the mainline
12 delivery points are the points, I think, where we deliver to
13 the LDCs or the industrial points.

14 And those are the pricing points. If you look at
15 where people trade off of, those are the areas that people
16 are looking at in the market. There's not any trading
17 points at wellheads or downstream; they're all at kind of
18 the interconnects on pipelines in areas or zones off the
19 pipeline.

20 MS. COCHRANE: Mr. Ellis, I'd like to ask you a
21 question about your Rehearing Request. You stated that the
22 posting information that we were requiring in -- are
23 requiring in the Rule, may violate state or other regulatory
24 guidelines, and I was wondering if you could explain more,
25 how you think that we might be conflicting with your other

1
2

1 regulatory requirements?

2 MR. ELLIS: Yes, that's a concern of PG&E's.
3 There is a tariff rule in PG&E's tariff, that requires them
4 to maintain the confidentiality of customer-specific,
5 commercially-sensitive information, and that's the
6 reference.

7 MS. COCHRANE: Okay, so it's just limited to
8 customer-specific information, and likely went to the
9 location named?

10 MR. ELLIS: That's correct. Both PG&E and the
11 SoCal Gas SDG&E joint system treat information concerning a
12 customer's individual nominations or flows, as confidential
13 and commercially-sensitive, and PG&E also has a tariff rule
14 approved by the CPUC, that requires them to maintain that
15 confidentiality.

16 MS. COCHRANE: Thank you.

17 MR. YOUNG: And just as a followup, the reg is 18
18 CFR 157.202-65.

19 MR. ELLSWORTH: This question is for Mr. Young.
20 You talk a little bit about gas control. I was kind of
21 wondering whether you could expand on exactly what type of
22 information they see. I think you mentioned line pack, so
23 they can look at pressure.

24 But do they actually -- are they also looking at
25 flows across large meters, or pool points, or what kind of

1
2

1 information are they actually collecting?

2 MR. YOUNG: Gas control, they get SCADA feeds, so
3 they'll see the real-time activities on the pipe on
4 different points.

5 I like to call it -- they get a dispatch, if you
6 will, every day, so the Nomination Scheduling Group will
7 take the orders from the customers, where all customers
8 bringing gas in at these receipt points, taking to these
9 delivery points.

10 The scheduling system will aggregate all that
11 together, and, at a point-by-point level, tell them, these
12 are the nominations, the schedules, or the confirmed volumes
13 at each of these interconnecting points.

14 And they are usually what I call the mainline
15 receipt and mainline delivery points. That's what they're
16 looking at.

17 Gas control will get that, they'll have their
18 SCADA screen, they'll know that I've got nominations of 150
19 million at this point, they see SCADA real-time, and they'll
20 see what they're doing, every day, and that's how they will
21 manage their pipe.

22 There is also a set of alarms, and they'll have
23 line pack estimates. They'll look at pressures, so there
24 are pressure alarms all throughout the pipe.

25 They manage -- you know, every gas control group

1
2

1 has a different set of SCADA screens, but they'll look at
2 the points that are relevant to them, alarms will come up,
3 and they'll manage accordingly, whether compressor stations
4 are running, and if something happens, the line pack drops
5 in one area, they might have to turn on a compressor to
6 bring more gas in from other areas, to make the
7 determination whether to bring gas in or out of storage.

8 Usually, their job is, can I ride this out,
9 without having to do anything, or do I need to make some
10 kind of adjustment to the system?

11 Sometimes that adjustment goes back -- comes back
12 to the scheduling group, which says, hey, we either need to
13 cut some nominations, or we need to get more gas brought
14 into the pipe, because we can't fill it with our current
15 line pack.

16 MR. QUINN: Can you explain what the scheduling
17 protocols are for flows off-system. You mentioned that one
18 of the places that gas can go, is off-system. How does
19 scheduling work for those flows?

20 MR. ELLIS: I'll try to. With reference to the
21 nomination model at page 10 of the presentation materials,
22 there's a box or a circle for OSD off-system deliveries.
23 Currently, on our system, our customers can nominate
24 supplies for delivery to PG&E.

25 That nomination will be confirmed by the system

1
2

1 operator and the gas will flow off-system. We do not have
2 CPUC authority to confirm nominations for deliveries back to
3 the interstates. For example, if you look at the map to the
4 Transwestern System, at Needles or to the El Paso System at
5 Topac or Aaronberg, when we receive that authority from the
6 CPUC, then we will be able to confirm nominations and those
7 volumes will be confirmed, and the aggregate of those
8 volumes is what we would propose as one of the three
9 elements at the level of detail of information that would be
10 of most use to anyone wanting to watch actual system
11 operations and demand and available capacity on our system.

12 That would be the aggregate of off-system
13 deliveries, the aggregate of on-system and deliveries to
14 storage. Storage is currently available and capacity is
15 currently available.

16 MR. QUINN: Could you explain why you think the
17 aggregate is the right number, rather than, say, deliveries
18 to within-state, to PG&E and deliveries back to the
19 interstates, in general?

20 MR. ELLIS: That's a question at a level of
21 detail I have not considered. The question is, for off-
22 system deliveries, why isn't it relevant to know, to
23 individual pipelines? It may be; I don't have an answer for
24 that question.

25 MR. QUINN: Thank you.

1
2

1 MS. COCHRANE: Oh, please go ahead.

2 MR. MURRELL: This is really for Mr. Young, but
3 also a little bit for Mr. Ellis. Mr. Young, you had a very
4 specific proposal to make a change.

5 Under your proposal, for your company, how many
6 points would end up having information reported, and how
7 does that compare to the number of points you believe your
8 company would have to report under the existing rule?

9 MR. YOUNG: We didn't do the analysis of the
10 exact numbers, but if you look at the couple thousand meters
11 that we have on our system right now, a majority of which, a
12 design capacity, it could be argued, would be 15 million or
13 more. We have a lot of four-inch meter runs in the pipe
14 that are, again, not pulling much, so virtually, you know,
15 75 to 80 percent, maybe 90 percent of the meters, would be
16 reported under the design capacity, if we argued that was
17 how to go.

18 If we didn't see that, that number would
19 probably drop significantly. I would say we would have --
20 gosh, I'd have to put a pencil to it, but, you know, a
21 hundred or so.

22 I mean, don't quote me on that, but it would be a
23 lot smaller, but the thing that we thought, was, you're
24 going to capture the same data, the same, and, I would
25 argue, more accurate data, with less meters, because then,

1
2

1 when we go through the design, identifying what meters do we
2 post, that's been a big question that we've had.

3 We've tried to do that, and we've had lots of
4 meetings with engineers and said, okay, let's get all the
5 meters and go through it, and right now, we're in the
6 process of identifying it one-by-one, based on pressures and
7 orifice plates, and, you know, rate of flow.

8 And that's the max that we can possibly do.
9 We're going to have a lot of meters out there that are never
10 going to flow more than 15 million a day. If we do, the
11 average flow will capture those, and that's why we want to
12 do the ten-day heat, because, yeah, we'll have more meters
13 there than -- we'll have a lot of meters where they're not
14 going to flow 15 million for, you know, more than, you know,
15 maybe 30 days a year, but it's more conservative, but you're
16 not going to have the big gap between all this excess
17 capacity being shown, and what's really there.

18 So we just want to do something to get the right,
19 most accurate number. And, you know, this doesn't
20 necessarily have to be the exact way to do it, but it was a
21 proposal to say, it seems to make more sense, and I think
22 most companies, at least in the TPA, they go to measurement
23 groups and they have measurement data.

24 Then they can do that query pretty simply, and if
25 it feels comfortable that that's correct, and then it's just

1
2

1 a matter of some pipelines would have to aggregate those to
2 the virtual points; some pipelines would not, because they
3 don't have virtual points.

4 But they could --

5 MR. MURRELL: In terms of the types of dynamics
6 that you see on your system, from one year to the next,
7 would you expect to see many changes in terms of points that
8 become eligible under your screen, in the next year or the
9 year after that? Would you see a lot of points dropping off
10 and being added to the list?

11 MR. YOUNG: No, I don't think there would be a
12 lot -- there shouldn't be a lot of points added. I mean,
13 there would be new points and new production that came on,
14 or new delivery points. If we had power plants, certainly
15 we'd do that.

16 In terms of meters dropping off, if we had
17 wellheads that have declined, but those would be pretty big
18 wellheads, if we're doing 15 million a day, so I don't see a
19 lot of changes. That's why we thought the yearly would be a
20 good number, because you wouldn't see a big change from year
21 to year; you'd have a consistent path throughout the year.

22 MR. MURRELL: Okay, thank you. Mr. Ellis, you
23 had kind of articulated a proposal that, in my mind, I was
24 trying to quantify in the same way. Do you have a sense of
25 what the impact would be, in terms of the number of points?

1
2

1 MR. ELLIS: Yes. The proposal I have, would
2 identify deliveries and capacity available at our receipt
3 points, with our interstate systems and with California
4 producers.

5 It would identify receipts or withdrawals from
6 storage, net aggregate, on a daily basis, and the difference
7 will be on-system demand, on-system usage.

8 We have that information available, readily
9 available today, so posting a separate screen that provides
10 it, is something we could do.

11 I'm not sure, Mr. Murrell, I caught Mr. Young's
12 proposal exactly. I did hear the part about looking at
13 average flows over the largest ten days, to identify the
14 15,000 MMBtu criteria. I did not gather, if he was speaking
15 exactly to nominations at those locations, or to deliveries
16 at those locations.

17 MR. YOUNG: It was based on physical at those
18 locations, physical deliveries.

19 MR. ELLIS: Thank you. We would not propose any
20 statement of data based on actual flows or measured flows.
21 For one thing, to begin with, you'd have to have the
22 capacity to do that, and that would be a costly undertaking,
23 or could be a costly undertaking for many systems.

24 But, even more fundamentally, I don't see the
25 value with respect to the Commission's transparency goals,

1
2

1 which we very much support. But I don't see the value with
2 respect to the Commission's transparency goals, in measuring
3 actual flows to locations of a particular size.

4 MR. YOUNG: Let me clarify. I wasn't saying to
5 post actual flows. I was saying to use actual flows to come
6 up with the meters to post.

7 So, yeah, I agree, we wouldn't want to post
8 anything, any actual data, daily, because that would be just
9 --

10 MS. COCHRANE: Just to clarify, too, I had
11 written down that you were talking about points where you
12 schedule and that would include the pools. I thought you
13 were talking about pool meters.

14 MR. YOUNG: Right, so you would have the -- if
15 somebody scheduled to the pool meter, those are oftentimes
16 an aggregation of a number of wells.

17 MS. COCHRANE: I'm sorry, a pool meter, as
18 opposed to, like, a pooling point. Virtual points?

19 MR. YOUNG: I guess it depends. Some pipelines
20 follow the pool meter; some people call it a virtual point.
21 It's kind of a paper aggregation point that people nominate
22 to, and, at the end of the month, a number of meters are
23 combined to show that's the volume at that paper point.

24 So the design capacity that I was -- or the
25 capacity I would look at, would be those meters, summed up.

1
2

1 If they were more than 15, then we would have a capacity
2 that we could compare the schedules next to on a daily
3 basis, but I wouldn't want to post any actual data every
4 day.

5 MR. PETERSON: Just so I can confirm, that would
6 apply both to receipt and delivery points; is that correct?

7 MR. YOUNG: Yes.

8 MR. PETERSON: But you couch that in terms of two
9 points that, I guess, are scheduled now?

10 MR. YOUNG: Right. I call them the commercial
11 scheduling points. They are points where people -- where
12 shippers do their nominations, and they come into our
13 systems, saying, I'm bringing gas from this point and taking
14 it to this point.

15 Those are often those virtual points. They don't
16 schedule at the hundred meters behind there; they nominate
17 at that one virtual or pool point, and so they would have a
18 nom of -- you know, as an example, if they had 100 meters
19 and they all did 100 Mcf, that would be 10,000 that they
20 would nom at that virtual point.

21 At the end of the month, they would sum all the
22 measurements at those points, compare it to the schedule to
23 allocate.

24 MR. PETERSON: And under the --

25 MS. COCHRANE: Bridgett.

1
2

1 MS. SHAHAN: I was just going to say, I guess I'm
2 a little bit confused, but if it's a virtual point, a paper
3 pool, we don't have any design capacity. It's just, for
4 Nicor and Natural, it's Natural's point, too, it is the
5 Chicago city gate at Nicor, and it is covering 75 actual
6 points that interconnect between Natural and Nicor, so
7 there's no design capacity in that.

8 So if you want to know what's scheduled on
9 Nicor's system on a daily basis, we can tell you that, and
10 it is the information that we get from the pipelines. It's
11 the pipelines' meters, it's the pipelines' reporting, and
12 that will be two virtual points, one for Natural, one for
13 Midwestern, and then several for the other -- that are
14 actual, physical interconnects with the other pipes.

15 I think there's about 13 others, and we know
16 what's scheduled there, and it's because the pipelines tell
17 us what's scheduled there. And if you want what actually
18 flows at all 96 interconnects, we know that, too.

19 But they're -- I'm just saying that they are kind
20 of two different -- they're very different worlds.

21 MR. PETERSON: So, currently, on your system
22 right now, we can look at interstate natural gas pipelines -
23 - and we do every day, and we see how much gas is delivered
24 to your city gate off Natural and other pipelines.

25 MS. SHAHAN: Correct.

1
2

1 MR. PETERSON: And so we see that. What we don't
2 know, is if Nicor has a massive market area gas storage
3 capability, for example, and some of that is not all
4 pipeline-owned storage, and so you can solve your demand
5 each day in that market, by relying on that.

6 I guess Mr. Ellis's in California, we know what
7 that number is, currently, on SoCal and on PG&E. I don't
8 know that we know what that number is, say, for Nicor, in
9 terms of the contribution of storage withdrawals on a given
10 day. We see the Chicago city gate price has maybe doubled
11 or whatever, because it's cold, we know what's going through
12 the pipelines, but the pipelines will get constrained,
13 they'll get max'd out, and there will be a large withdrawal
14 capability probably brought to bear by Nicor.

15 And so from an oversight standpoint, we don't
16 have that window right now, to understand what's going on.

17 MS. SHAHAN: And we don't have that on a daily
18 basis, either. I mean, it's the end-of-the month figuring
19 out with the schedules, again, and on our system, our
20 transportation customers are scheduling to their pool, to
21 their contract, or they're scheduling into storage. That's
22 basically the choices they have.

23 And at the end of the month, we figure out all
24 their customers that are covered by their contract, whether
25 it's just themselves or thousands, and coordinate, like,

1
2

1 well, you had this much storage this month and you've
2 ratcheted down to here, or you're up to here, and it's
3 definitely a lag of knowing, of dealing with all the
4 paperwork.

5 I guess the easiest way to say it, is, it's the
6 control room deals real-time and makes it work every day,
7 and then a month later, all the paperwork is figured out, of
8 who did what.

9 MR. YOUNG: I mean, I would classify the LDCs,
10 just like the gathering. I mean, I do think you get most of
11 the data that you need, from the interconnect delivering to
12 them.

13 And if they do have a storage pool, eventually
14 that gas has still got to get back there, so the gas going
15 to the LDCs, is coming through the mainline delivery points
16 at some point, just like on the gathering side.

17 MS. COCHRANE: I don't think Staff has any other
18 questions. Do any of the panelists want to say anything in
19 addition, or clarify anything?

20 (No response.)

21 MS. COCHRANE: Okay, all right, why don't we --
22 no problem stopping early. So why don't we take a ten-
23 minute break and then we'll start with Panel III, so let's
24 come back at 11:30. Thank you.

25 (Recess.)

1
2

1 MS. COCHRANE: All right, thank you. Why don't
2 we start? This is the third panel, addressing the cost of
3 compliance. Again, we have John Ellis joining us again, and
4 Will McCandless, Director of Pipeline Portfolio, Commercial
5 Operations with Enogex, on behalf of the Texas Pipeline
6 Association.

7 Thank you for agreeing to speak on this panel,
8 and I was wondering, do either of you care to go first?
9 Okay.

10 MR. McCANDLESS: Well, thank you. First, I'd
11 like to, you know, thank the Staff, you know, for allowing
12 me to be here and to speak to some of these issues. I
13 appreciate the opportunity.

14 Again, my name is William McCandless. I'm a
15 Director at Enogex, an Oklahoma company. My primary
16 responsibility is, I'm -- one of my primary
17 responsibilities, is to manage and direct the Volume Control
18 and Scheduling Group, so I have a lot of experience, and
19 this Rule will have some impact on the day-to-day function
20 of me and my staff.

21 I'm here today to talk about the cost and effort
22 to implement Order 720 and maybe some proposed changes that
23 would allow us to better implement it, more cost-
24 effectively.

25 I still believe there is still much that is vague

1
2

1 about the Order, and there's some confusion on actually how
2 to implement it. We are in constant talks with engineers,
3 internally, on what does this mean?

4 I think you've heard some statements earlier
5 about a four-inch meter run, could, theoretically, get
6 15,000 MMBtus through it on a daily basis.

7 On the Enogex system, that would be about 5,000
8 meters, 5,000 to 6,000 meters, so it would be a significant
9 reporting requirement for our company.

10 Our members have estimated the cost to
11 implement, and the timeframe, based on some very basic
12 assumptions. These assumptions will have the impact to
13 actually reduce our costs.

14 The first assumption is that reporting will only
15 occur at nominated receipt and delivery points. This would
16 also include virtual points.

17 This also includes those meters, those virtual
18 points and meters downstream of just gathering and
19 processing facilities, so the Enogex system and many of the
20 interstates, have gathering systems that feed our intrastate
21 systems, and we receive gas from multiple locations.

22 I think you used the term, "city gates," prior,
23 and if we can minimize the number of those meters that
24 actually have to be reported, that would greatly reduce our
25 costs.

1
2

1 We will not be -- another assumption is that we
2 will not be required to change our current nomination and
3 contracting processes. I think one of our big concerns --
4 we've implemented systems, we've implemented processes to
5 really manage this day-to-day business, this month-to-month
6 business.

7 We're really hoping that the impact of this
8 reporting, does not have a significant change in the way we
9 contract today and the way we manage our business today,
10 from the day-to-day nominations management.

11 We're also asking that -- we're also assuming
12 that the posting is only required on standard business days.
13 Many of the intrastates, many of the members of the TPA,
14 don't necessarily staff a weekend volume control group.

15 We may have a weekend gas control that manages
16 the physical aspects of the pipe, but as far as the
17 scheduled aspects and managing the contracts and the
18 nominations, that tends to be a normal business-days
19 function, and requiring us to report on a weekend or on a
20 holiday basis, would mean we'd have to increase our staffs,
21 therefore, our costs.

22 I understand that an estimate of \$30,000 was
23 included as the cost to implement the Order 720. This is
24 the number I emphatically disagree with, even with the
25 assumptions I noted previously.

1
2

1 There were no members of the TPA that actually
2 introduced or provided numbers in that neighborhood.

3 Based on information provided by TPA members,
4 average costs to implement, again, assuming these
5 assumptions, was \$100,000, with a \$50,000 a year annual cost
6 to maintain.

7 Some of our members' actual startup costs are
8 much higher, because they're starting from scratch. They're
9 not as technical or they don't have the technology in place.
10 There's an initial technology they're going to have to
11 implement to better facilitate the scheduling and
12 aggregation of scheduling information.

13 Included in these costs, were hours for -- and
14 this is under implementation -- was the IT group to collect
15 business requirements, develop and then implement a
16 solution; for users to go through an acceptable -- through a
17 period of acceptance testing; legal hours for consulting and
18 reviewing of the business requirements to ensure a solution
19 meets FERC reporting requirements.

20 Because there's no safe harbor in this Rule,
21 there is potential liability, and because of that, our
22 internal audit and our external audit, are going to want to
23 get involved. This means we're going to have to develop
24 SOCs controls, business processes; we're going to have to
25 document those controls, to ensure that behind the scenes,

1
2

1 even though, as we're reporting, that there's documentation
2 from managers and from the people actually doing the work,
3 that they've checked off the box and they're actually doing
4 what they're supposed to be doing, and that they are
5 verifying the numbers, as appropriate.

6 The fact that, again, that it is a potential
7 material liability, forces us to go through this audit
8 process.

9 The commercial groups will need to communicate
10 with our large end users and producers, informing them of
11 the new reporting requirements under the new Rule, and we
12 expect many of our customers will argue confidentiality.
13 Many of our large end users have confidentiality agreements
14 or clauses within their contracts.

15 Right now, we know that that's going to be a
16 touch point for many of our customers, and it's just going
17 to require additional time for commercial, to actually walk
18 them through the Rule and why this is happening, so it's
19 just additional time.

20 And, finally, there are some direct costs
21 associated with computer hardware and software.

22 On an ongoing basis, IT maintenance associated
23 with the new hardware updates, software, system upgrades,
24 and replacements, there's ongoing monthly SOCs control
25 documentation and testing that needs to go on.

1
2

1 Executing the actual data exports, verifying and
2 then posting, if you, you know -- and, again, this is an
3 area where, if you had 6,000 meters you had to report
4 against, versus -- it's one number, versus if it was 150
5 that you could verify against, that's another number, so,
6 again, for us, we prefer the lower number that would
7 include virtual points that I think were mentioned
8 previously.

9 And, finally, there's no doubt that the changes
10 that you've made in this latest Order, to move away from
11 actuals, benefitted us greatly. It reduced the costs
12 greatly, and we appreciate that.

13 However, the \$150,000; \$100,000 for
14 implementation and \$50,000 for ongoing, still remains very
15 material, a very material expense for many of the members of
16 the TPA, including my company, Enogex.

17 In the past three months, my company, just to
18 give some flavor, has gone through staff and salary
19 reductions, hiring freezes, and severe budget cuts, so we
20 appreciate your consideration and thank you for the time.

21 MS. COCHRANE: Thank you. Mr. Ellis?

22 MR. ELLIS: Thank you. For San Diego Gas and
23 Electric Company and Southern California Gas Company, first
24 I want to say that we very much support the Commission's
25 price transparency goals.

1
2

1 We have an electronic bulletin board that has a
2 great deal of information available today, and the first
3 question that we face in trying to come up with an estimate
4 of costs for compliance with Order 720, is to understand
5 what it is that the Commission would want to see from our
6 systems, in addition to what we have already.

7 One logical interpretation of Order Number 720,
8 would ask for a listing of customers who have meters of a
9 certain size, first, the identification, the list of
10 customers, would have a meter with a delivery capacity of a
11 certain size.

12 We do not currently have that functionality
13 today. The point that I would make there, is, if that
14 information were provided, along with a format that would
15 indicate scheduled volumes to each of those customers or
16 locations, the numbers that would be posted next to it,
17 would be zero.

18 What would be the cost to set up a screen or a
19 board that listed the number of customers and present next
20 to those customers, on a daily basis, what are the
21 nominations for all of them that would be zero.

22 There would be a cost to come up with that list,
23 and I don't see any benefit to posting zero next to it every
24 day, and that is, in fact, what the information would be for
25 SoCal Gas and SDG&E.

1
2

1 The second would be to identify nominations at
2 the pool level. In my presentation for the second panel, I
3 mentioned the fact that most nominations are handled through
4 contract marketers or through accounts with multiple
5 facilities behind them.

6 There would be another cost, different from the
7 first, if the idea were to identify and provide a nominated
8 daily number for pools. That could be done. It would come
9 at another cost, and that cost would be less than a cost to
10 identify and list individual customers with a meter capacity
11 of a certain size.

12 There, I question the value of having nominated
13 daily information for pools, for pooled accounts.

14 The third would be the information that we
15 proposed in the second panel, and that is the aggregate of
16 on-system demand, on nominations to storage, that is, in the
17 aggregate, what is being injected or what is being withdrawn
18 on a net basis from storage, and off-system deliveries,
19 whether that's an aggregate of all off-system deliveries,
20 or, as Dr. Quinn suggested, off-system deliveries to
21 individual locations.

22
23
24
25

1
2

1 That number I think would be significantly less
2 for us, and that is primarily because we already have much
3 of this information available. So that third proposal is
4 one that could be accomplished at a reasonable cost.

5 We have, as part of the presentation materials,
6 an estimate from PG&E that is stated in terms of hours
7 rather than dollars for startup costs. I believe their
8 estimate is for the first of the three levels I proposed.
9 That is, what would be the estimated startup burden in terms
10 of hours to develop a screen or a listing of all delivery
11 locations with a meter capacity of a certain size.

12 But again, for PG&E I believe the information
13 that would be posted next to each of those listed customers
14 or locations, while it would not be zero as it would be for
15 SoCalGas and SDG&E, it would be essentially a meaningless
16 number because each of these customers enjoy balancing
17 flexibility under their CPUC-approved transportation rates
18 that do not require them to nominate the volumes on a daily
19 basis to individual facilities.

20 That said, I believe the estimate that PG&E has
21 presented is the most detailed of the three levels I
22 propose.

23 I would also note that we are speaking about
24 SoCalGas and SDG&E as one EBB. PG&E's Pipe Ranger System is
25 another. Those are systems that have been in place for more

1
2

1 than 10 years. They have a lot of functionality, a lot of
2 information that is already posted.

3 I am sure that the startup costs for other AGA
4 member companies would be quite different, but I wanted to
5 present this information on behalf of the companies I was
6 asked to speak for.

7 Thank you.

8 MS. COCHRANE: Questions?

9 MR. REICH: Just a quick clarification,
10 Mr. McCandless. The \$150,000 estimate, is that based
11 on--that is based on your understanding of what is currently
12 in the Order? Or perhaps some kind of continuum to clean it
13 up?

14 MR. McCANDLESS: I think it's a continuum to
15 clean it up, because I think the way it is currently written
16 to require posting of information at meters greater than
17 15,000, and the fact that our businesses, even though we
18 flow--you know, we have numerous, in our company 90 percent
19 of our meters meet that requirement. But we don't nominate
20 at that level.

21 So there is no scheduled information necessarily
22 at that level. And so the assumptions we were making is
23 that what you are really looking for is schedule
24 information. You're looking for the aggregate of that
25 information at market points, or at points where wholesale

1
2

1 gas is bought and sold.

2 So we believe what you're really looking for is
3 maybe the information at the virtual point. And so if we
4 can get to the virtual point, that data is readily
5 available. That is how we conduct business today. I think
6 many of the intrastates support pooling, or one form of
7 pooling, and if they don't they do it at the meter level,
8 which they would report at that level.

9 So that is our preferred method. And again I
10 think one of the questions that was asked was how to reduce
11 costs. And for us, if we could report at the pooling level,
12 or at the virtual meter level, that would be one significant
13 method to reduce costs.

14 Did that help?

15 MR. REICH: Oh, yes. And also you described your
16 process to develop the posting system. Can you--do you have
17 a sense of how long that process would take, say shortest to
18 longest?

19 MR. McCANDLESS: Shortest to longest? You know,
20 there's Enogex and what I think we can do, and I think
21 there's--but, you know, there's the companies within TPA as
22 well and all the other intrastates. I think you would find
23 a wide variety of technical capabilities and a wide variety
24 of systems and capabilities within their companies.

25 Enogex, I believe the 150 days, based on these

1
2

1 assumptions, based on a more simplified but using a virtual
2 pool is probably doable. If you start looking at actual
3 meters, or we could get information up on the web just like
4 John Ellis has said, but it would be meaningless.

5 If you require schedule information, it would
6 entail us changing our business practices to require our
7 customers to start scheduling, which I think for our
8 customers would be a nightmare. We would go from dozens and
9 hundreds of nominations to tens of thousands of nominations.
10 And I don't even know if our systems could handle that type
11 of load.

12 So it would require significant changes to
13 systems, significant effort, and it would almost be
14 inestimable. We would be back up in the million dollar
15 range again.

16 MR. REICH: And I know that SoCalGas and PG&E
17 have their own systems going, and various interstate
18 pipelines and I'm sure some intrastate pipelines have some
19 kind of posting process. Are there any--or are you aware of
20 any packages, or is this all internal development based on
21 the estimate of kind of how long it will take it to put it
22 together? Or is there a contracting element there?

23 MR. McCANDLESS: There can be--most of ours would
24 be internal. I know there are third-party BBS types that
25 provide that as a service, so that all you have to do is

1
2

1 provide the information to the BBS.

2 I think getting the information up to the web is
3 the least-cost part of it. I think that technology is
4 pretty well established. It's the aggregation of the
5 business data itself, and it's pulling it into a format.
6 It's the definition of what the capacity is. It's the
7 definition of available capacity. It's pulling all the
8 meters, making sure that you've pulled all the meters that
9 meet the requirement, and that you're doing this on a daily
10 basis potentially numerous times, depending on the number of
11 cycles you support, or the number of times you make changes
12 to your nominations.

13 So I think it is the actual pulling of the
14 information and the methodology of that that entails most of
15 the cost. Getting it up on the web is not near--it's a
16 well-established technology.

17 MR. ELLIS: For SoCalGas and SDG&E I don't know
18 the answer to your question. I don't know to what extent
19 there are packages available that could be used as a base or
20 a floor for individual systems EBB.

21 I do know that we spent a great deal of money, I
22 believe in the millions, to get our system revised as of
23 October 1st, 2008, to provide the detail with respect to our
24 firm access rights system, but I don't know to what extent
25 that was based on a model or a base that's available

1
2

1 commercially.

2 MR. PETERSON: Mr. McCandless, on the--we concur
3 with your general thought in terms of I was involved in
4 looking at some cost issues involved in comporting with this
5 rule, and it was our presumption that many of the potential
6 covered parties by this had information on their operations.

7 And in fact many of the potential parties that
8 would be covered by this rule, some of them have interstate
9 natural gas pipeline companies under their holding company
10 umbrella. This is a standard thing they already do. So
11 this is not a new thing for some that would be covered by
12 this rule.

13 And as you note, you can go to--there are
14 software companies in Houston and elsewhere that specialize
15 in offering EBB systems, informational posting systems, akin
16 to what the interstates already do. It is kind of a canned
17 thing.

18 Our understanding is that is not terribly
19 expensive. But your comments I think are helpful to us in
20 noting that. So that side of things we didn't anticipate,
21 frankly, to be that costly.

22 But the process issues in taking what some
23 parties have currently and then transferring that into, you
24 know, a publicly disclosable format, that is something we
25 were trying to get more information on today. And we

1
2

1 suspect that there's a lot of variability in terms of the
2 capabilities of different parties to do that currently, as
3 well.

4 So anyway, I wanted to note that. In terms of
5 the timeline, I think TPA said that one thing they might be
6 seeking in comporting with this is, aside from the cost
7 issue, is do the challenges of, at least for some of their
8 members in gathering this information, you might need
9 additional time to come into compliance with the rule. And
10 that is something that, if so, we would like to hear some
11 more specifics about, about what is entailed with that.

12 So I don't know if you have those thoughts now.
13 Those comments were noted in Rehearing, and we saw them.

14 MR. McCANDLESS: I can speak to a little bit.
15 And I think you make a good point. But even a company that
16 has interstate and intrastate business--I'm going to go back
17 to your first one first--it is true that the mechanism to
18 get information from the systems up to the web is in place
19 and that they could leverage that technology, that
20 expertise.

21 What may be misunderstood, or not fully
22 appreciated, is the business paradigm, the business
23 processes, the way that the intrastate conducts business may
24 not marry well with the way the interstates conduct
25 business. And so it may not be a simple one-to-one

1
2

1 translation.

2 There are some assumptions, and I make some of
3 those in here about virtual pools. A lot of the intrastates
4 and city-gates rely heavily on virtual pools to deliver gas
5 to our end users, to pool gas from gathering systems. For
6 example, at Enogex we don't have receipts at the--we have
7 six or seven processing plants with stubs. We don't
8 necessarily receive gas from those on a scheduled basis
9 individually.

10 We have one major receipt point from the
11 gathering system that's an accumulation of all the tailgates
12 of the plants as well as gas that's directly brought in
13 that's not processed. So it's a virtual point, and that's
14 where the scheduling begins.

15 And so that's a little different than maybe what
16 you would expect from an interstate.

17 As far as costs, it is really a function of
18 narrowing down the rules. Right now it is up in the air
19 because we are still unsure as to what we're going to
20 actually have to implement. It's a function of, you know,
21 are we going to have to live with the 15,000 a day rule?
22 And what does that mean, even if we post meaningless
23 information up on the web?

24 You know, we don't really want to go there. We
25 really want to provide the most meaningful information to

1
2

1 facilitate the transparency that you all are looking for,
2 and that the market desires.

3 So--and again we are proposing some solutions
4 for that. But if it's required to change our business
5 processes, or if you're looking for much more information
6 than we currently are estimating, the cost estimates could
7 go up ten-fold, and the time estimates could go up ten-fold
8 as well. It could take multiple years.

9 Again, it is a function of our systems as well
10 that are in place.

11 MR. PETERSON: Mr. Ellis spoke earlier about the
12 existence of the PG&E and SoCal systems that are long held,
13 and people have relied on those. Do you--I will presume you
14 are familiar with those, but you have information now in
15 terms of solve your network each day.

16 MR. McCANDLESS: Um-hmm.

17 MR. PETERSON: I guess what challenges would
18 there be if you're not doing a detailed daily version of it
19 by point, but you're doing something more rolled up than
20 that, what--I mean, how does that affect your time line to
21 roll something out and your costs associated with that?

22 MR. McCANDLESS: We--

23 MR. PETERSON: And what information do you have
24 now that you could bring to bear to provide the market with
25 a clearer picture of--you know, the Oklahoma market is kind

1
2

1 of a place where we do not have very good demand
2 information, frankly. And so what exists already that would
3 be ready to go that you could implement in a system that
4 would shed more light on that?

5 MR. McCANDLESS: Very quickly, what we can
6 implement very quickly would be a system where we reported,
7 again, the virtual meters, the pools where we weren't
8 necessarily required to report at the actual meter level.

9 Most of it, we do balance our system daily. We
10 go through a process every day. We balance the system
11 daily. That doesn't mean everybody is in balance; it just
12 means we compare our noms to actual flows.

13 Those actual flows may be--again, it may be the
14 sum of 100 different wells. And so I may be measuring a
15 customer, a customer may have nominated 200, or 20,000
16 MMBtus. Their actual flow of the 100 wells might have been
17 20,257. And so, you know, they're building up an imbalance
18 in one direction.

19 Part of the job of the volume control group is to
20 monitor those to keep them within a reasonable tolerance,
21 and then bring them back. And then, if needed, request
22 action to bring--request action of the customer to bring
23 that back in balance.

24 So it is being monitored daily. We have got a
25 lot of good information on a daily basis at the scheduling

1
2

1 and contractual level. I think the struggle I have is, when
2 you're looking to dive into--some of the rule speaks to the
3 actual nature of the business, and I think the lady I think
4 from Nicor did a good job of saying there's these two
5 worlds. There's the nomination and contractual world where
6 you're balancing contracts. And then there's the physical
7 world that occurs underneath that that the gas control
8 groups manage. And the two worlds sort of live in parallel
9 and they balance. At the end of every month you try to get
10 everybody into balance, but the rule is sort of saying we
11 want to--what I hear you saying is you want to see what's
12 going on at the scheduling level, that's where the market
13 lives; but what's actually going on at the actual level may
14 be different.

15 There may be some activity there that is not
16 representative of the nomination world, of the contractual
17 world.

18 MR. REICH: I just want to get back once again to
19 the estimate you gave earlier, the \$150,000 estimate. In
20 that estimate do you include having to develop any kind of
21 operational data that you don't already generate? Or is
22 this all based on in a world where we're doing virtual
23 points?

24 MR. McCANDLESS: It's based on the world
25 primarily of virtual points where we identify the 150 or 200

1
2

1 wells--or not wells, but meters, or virtual locations that
2 will have to be identified and have an engineer at this time
3 to actually come up with a number, what that theoretical
4 number is.

5 If we have to go in and identify the 6,000 or
6 5,000 meters, that number will grow considerably to have an
7 engineer sit down at each of those meters and back into a
8 design capacity would be extensive. We don't just--that's
9 not an attribute that we keep with each of those meters.

10 MR. REICH: Thank you.

11 MR. PETERSON: And the reason why the potential
12 meter numbers are so high I presume is mainly because of
13 the--is that more of a supply issue where you have lots of
14 wells that could flow up to a certain level each day, many
15 don't--

16 MR. McCANDLESS: Right.

17 MR. PETERSON: So it's not a delivery thing,
18 mainly? It's really on your receipt side? Is that correct?

19 MR. McCANDLESS: That's correct. It's primarily
20 on the receipt side. A lot of it is--you know, a 4-inch
21 meter tube is sort of standard 4 to 6 inch on our system,
22 it's sort of standard. If you could 15,000 through it, you
23 know, you may have a well that comes on, and again the way
24 the decline rates work, you may have a well that may come on
25 and the very first day produce 15- or 18,000, so you see the

1
2

1 meter run for that size, but very quickly, inside that
2 month, and then from that point forward for the rest of the
3 life of that well, it's going to produce significantly less
4 than that 15,000 a day meter. It will produce, you know,
5 1,000 to 2,000 a day. And again, we would like to avoid
6 having to report--I think in reporting it, it is just going
7 to be superfluous information that you would otherwise get.
8 I think you would get more accurate information if you got
9 it at the virtual point.

10 Because at the virtual point you would basically
11 be netting all the gathering meters. I don't know if that
12 makes sense or not. Versus just the ones that are of
13 significant size.

14 MS. COCHRANE: Any other questions?

15 (No response.)

16 MS. COCHRANE: Okay, thank you.

17 As I said, there is no reason why we can't end
18 early, especially since it is lunchtime. I want to thank
19 everyone again for coming, and especially the panelists. I
20 really appreciate some of you traveling here, and hopefully
21 the fog has lifted and when you leave you will get a nice
22 view of the Capitol as you leave, instead of the fog we had
23 this morning.

24 What I would like to do is, there was a proposal
25 that was presented by the TPA during the panel presentation.

1
2

1 So there are a couple of things I would like to do.

2 I would like to provide a 10-day period for three
3 things to happen. I want to narrow what we receive at the
4 end of the 10 days, which is March 30th, but first off there
5 were a few panelists who provided--Mr. Ellis, you provided a
6 Power Point. Then there were two maps that were provided.

7 If you could please file those in the record in
8 this proceeding so that others have it. I know that the
9 Southwest one you might have to scan that since it had some
10 handwritten things on it, which was fine. But if you could
11 please put those in the record I would appreciate that.

12 Also, if any panelist wants to correct the
13 record. I don't want to open it up to a lot. This was
14 really intended to get operational information, not more
15 legal argument or anything, but if anybody wants to correct
16 the record of statements that were made when you go back and
17 think about it, if you think you made a misstatement that
18 you would like to correct, please do that.

19 Then also I would like to ask the TPA if you
20 could provide a written statement of this proposal. There
21 was some discussion back and forth. If you could just
22 clarify so that it is more clear what the proposal is.

23 At this stage of the proceeding, we do have a
24 Final Rule. We have Requests For Rehearing that are already
25 filed. We are in the Rehearing stage. So it was not the

1
2

1 intent to get more proposals. However, you know, the
2 Commission wants to make this work and we want to have a
3 rule that works.

4 We did grant an extension of time for compliance
5 with the Rule, so we have some time to think about it and
6 make sure that we get the information that we need. As
7 people have said, we get valuable information and meaningful
8 information.

9 So Staff will take everything that we have heard
10 so far and make a recommendation to the Commission. If the
11 Commission decides that this proposal is something they want
12 to consider, then we will have to go through Notice and
13 Comment Procedures under the APA at this point.

14 So I would not want this 10-day period to be a
15 time for people to respond to the proposal because right now
16 this is Staff. But, you know, if the Commission is to
17 consider it then there will be an opportunity for Notice and
18 Comment. We will put it in the Federal Register for all of
19 the members and people since this does address a lot of
20 entities who are not normally under our jurisdiction and we
21 want to make sure that everybody has an opportunity to see
22 the proposal and comment on it, and not just those of you
23 who are here at the technical conference.

24 So does that make sense, Gabe? Does that make
25 sense Mike?

1
2

1 (Nods in the affirmative.)

2 MS. COCHRANE: I'm checking with my attorneys to
3 make sure I'm properly stating how we are going to proceed
4 under the APA.

5 So with that, I thank you all very much. Take
6 care.

7 MR. ELLIS: Thank you for the opportunity come
8 here today.

9 (Whereupon, at 12:17 p.m., Wednesday, March 18,
10 2009, the technical conference was adjourned.)

11
12
13
14
15
16
17
18
19
20
21
22
23
24
25