BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

ORDER NO. 720, PIPELINE POSTING : Docket Number

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

NATURAL GAS ACT :

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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.

APPEARANCES:

Federal Energy Regulatory Commission:

William Murrell

Jerome Pederson

Christopher Ellsworth

Christopher Peterson

Arnie Quinn

Steven Reich

Gabriel Sterling, III

Panels:

Roger A. Farrell

President & COO

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

Larry Black

Manager, Gas Purchases and Transportation

Southwest Gas Corporation

Vonda Seckler

Managing Executive, Gas Supply

Ameren Corporation (on behalf of AGA)

Robert W. Young

Director of Scheduling

Energy Transfer (on behalf of TPA)

APPEARANCES (Continued):

John Ellis
Senior Counsel
San Diego Gas & Electric/Southern California
Gas Company

Bridget Shahan
Assistant General Counsel & Chief Compliance Officer
Nicor Gas

Michael Novak
Assistant General Manager, Federal Regulatory Affairs
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San Diego Gas & Electric/Southern California
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Will McCandless
Director Pipeline Portfolio - Commercial Operations
Exogex LLC (on behalf of TPA)

P R O C E E D I N G S

(9:00 a.m.)

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

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.

Requests for rehearing of the Rule, were filed on December 22nd. On January 15th of this year, the Commission granted and 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.

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.

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.

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

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

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

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

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

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

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

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

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

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

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

So the first is panel is designed to review structural issues in the Commission's designation of major non-interstate pipelines, and I really appreciate you coming today to talk about this issue.

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

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

Thank you very much. We can just start.

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

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

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

MS. COCHRANE: Yes, you just flip it.

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

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

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

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

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

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

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

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

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

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

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

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

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

The shaded areas that you see on there, represent Southwest franchise territories. That's not to imply that there are, indeed, distribution lines throughout every bit of that shaded area. Much of that is desert with cactus and jack rabbits in it, but it is a franchise area.

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

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

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

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

Part of what is now Northwest and Northern California area, was acquired in earlier years. In 2005, we acquired the distribution business of Avista Corporation, around the Lake Tahoe area, thereby completing what we now refer to as our Northern California Operations.

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

Today, they are all Divisions operated by Southwest Gas.

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

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

Four of the six areas are relatively small, and, independently, would fall well below the 50 million decatherm threshold, but, more importantly, really, because of the size and the makeup of the market demands on them, reporting data pursuant to Order 720, would not really contribute any meaningful addition to the marketplace intelligence that we believe you are trying to gather.

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

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

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

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

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

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

And those points where we do receive that gas on the interstate system, are all at known, existing interstate scheduling points. Our facilities, our only receiving points there, in all areas except Southern Nevada, which is an exception I'll discuss, all the gas scheduled to Southwest by an upstream pipeline, is scheduled to what we would refer to as virtual delivery points.

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

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

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

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

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

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

All four of these LDCs were formed by a series of acquisitions to form Ameren Corporation's LDC Group, mostly, independently operating, except for a few emergency interconnects between the Illinois facilities, and those interconnects are only used for emergency system operating purposes.

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

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

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

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

These are areas where there is no market being developed, just by the nature of the customers that are behind those gates, heat-sensitive, and we would like for clarification that when we look at the delivery threshold facility-by-facility, that the non-contiguous areas could be segregated and looked at on their own merits.

MS. COCHRANE: Thank you. Mr. Farrell?

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

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

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

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

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

MS. COCHRANE: Could you just wait a second? Let me check with the -- can you hear him, if he's over there?

(Pause.)

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

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

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

(Discussion off the record.)

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

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

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

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

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

They contain liquids, they contain hydrogen sulfide, CO2, the full gamut, not -- you know, there are some wells that are pipeline quality, by nature, but certainly, in the majority of the cases, the gas has to be conditioned in order to be sold, to be sold into the interstate or intrastate commerce, okay?

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

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

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

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

After you do that, you process the gas. We call processing essentially -- you know, we cool the gas down to minus-150 to minus-200 degrees Fahrenheit, and what happens there?

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

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

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

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

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

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

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

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

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

Southern Union itself, we have four plants. We're connected to stub lines that are interconnected, they go to multiple markets. The markets are always the intras and the inters, okay?

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

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

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

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

So that is the purpose of the stub lines.

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

And, moreover, supplies upstream of a processing/conditioning/treating plant, those are not pricing points; it's not bought and sold upstream of the plant.

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

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

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

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

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

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

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

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

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

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

Then also I'd like to propose that we adopt the posting requirements that we're going to proffer in the next segment, that I think resolves a lot of the issues and concerns of the LDCs, and some of the other market participants.

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

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

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

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

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

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

That would be about the only one I would, you know, the only gathering function that would be downstream of a process facility that I could come up with.

MR. REICH: Is that common?

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

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

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

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

MR. REICH: Thank you.

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

I suspect it's a range, but can you give us a flavor for the magnitude of the million cubic feet per day ranges for these facilities?

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

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

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

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

MR. FARRELL: That would be correct.

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

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

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

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

MR. PETERSON: Right.

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

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

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

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

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

MR. PETERSON: Thank you.

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

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

MS. SECKLER: That's correct.

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

MS. SECKLER: Correct.

MR. REICH: Am I correct?

MS. SECKLER: Yes.

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

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

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

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

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

MS. SECKLER: Yes.

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

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

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

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

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

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

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

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

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

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

(Laughter.)

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

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

They're not really handled any differently, other than as with any major customer, particularly one who has what may be a volatile load pattern like a power plant might be. We have much more ongoing and regular communications with those customers about what their plans are for the day, the gas that they intend to get delivered through our system for their use that day and so forth, where in most of our service territories, the demand, other than our residential heat-sensitive load, is a commercial/industrial load that's fairly flat, fairly regular on a day-to-day basis, and really doesn't require a lot of hour-to-hour, or, you know, minute-by-minute communication.

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

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

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

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

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

MR. REICH: Thank you.

MS. COCHRANE: Chris?

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

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

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

MR. ELLSWORTH: Okay.

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

MR. ELLSWORTH: Okay.

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

MS. SECKLER: That's correct.

MR. PEDERSON: What are those situations?

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

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

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

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

MR. BLACK: I would just speak for Southwest, and I certainly don't know what all the different LDC companies have in their quiver for these issues. Our systems that I've described to you are not interconnected in any way. Clearly some of them are hundreds of miles apart, so they wouldn't be. And even the two that appear to lay adjacent to each other in Arizona were designed and built entirely separately by different companies for different markets, and they do not have an interconnect between the two in the distribution side.

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

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

MR. FARRELL: It is possible that you could have some non-contiguous systems coming into an interstate or a major non-interstate into one. That volume could be pooled, you know, for supply purposes or under an agreement, but if the receipt points or the delivery points from these non-contiguous systems into the major non-interstate or the interstate exceed 15,000 MMBtu per day, or whatever threshold you determine, those volumes will be captured under the proposal that's in front of us.

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

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

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

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

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

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

MR. PEDERSON: Thank you.

MS. COCHRANE: Did you have a question?

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

MR. BLACK: Well speaking for Southwest there are some transportation contracts that we hold on the interstate pipeline in Arizona that may serve both the central Arizona and southern Arizona divisions for transportation service. But again, each of those will be scheduled to known scheduling points by the pipeline and that volume will be captured, either way. And they will be point by point. So I can't even remember right now exactly which points are in our southern Arizona division off the pipe, and which are in the central, because we have like 27 of them in one pipeline company, and literally hundreds of actual meters behind those points, but they would all be reported either way.

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

MR. STERLING: Thank you.

MS. COCHRANE: Any other questions?

(No response.)

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

Thank you, very much.

Panel two can come on up.

(Pause.)

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

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

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

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

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

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

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

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

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

LDCs operationally manage their systems to service all customers with some limited exceptions that are usually spelled out in tariffs that are approved by state regulators.

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

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

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

Thank you.

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

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

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

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

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

The other division is the Gas Supply Department. It is making sure that sufficient gas is scheduled to the city-gate. Now what they are doing is they are handling the nominations, the schedules, and the confirmations. And for our largest interstate pipeline supplier, which is Natural, we have 75 physical interconnects but we have one scheduling point for Natural, and Gas Supply is dealing with that one central, or virtual, scheduling point.

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

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

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

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

That is what we can do upstream.

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

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

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

And if it doesn't happen and we have to do something, then we will do something. Let me see if I've covered all of what I wanted to say. Basically I just wanted to say that also the transportation customers are scheduling on the interstate to a virtual point. And then they are scheduling once they come onto our system to what we call pools, which are virtual points.

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

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

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

So thank you.

MS. COCHRANE: Thank you very much.

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

Rehearing.

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

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

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

The third point is a function of editing a presentation while traveling and having access to the presentation by Blackberry--the point is that both SDG&E/SoCalGas and PG&E already post aggregated on system demand information. This would be an aggregate of the receipts of the different interstate interconnects from California production. The question that's asked by one commenter is: Is this true for SoCalGas? The answer is: Yes, it is.

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

The second slide is--

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

MR. ELLIS: Sure.

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

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

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

MR. ELLIS: The city-gate is a virtual point. It is not a specific physical location. It is a point at which pooled supplies can be traded, received in and out of the system, but there is no one physical location.

MS. COCHRANE: I just wanted to clarify that.

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

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

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

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

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

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

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

As I understand it, the intent of Order No. 720 is to gather information with regard to end-use facilities of a certain size. The first point here is that these end-use facilities typically are going to be served through pooled accounts, and there is no price formation downstream of the city-gate.

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

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

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

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

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

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

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

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

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

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

The conclusion is that requiring of posting of scheduled volumes to end-use delivery points on the California LDCs' systems will not facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. That is because, again, on the SDG&E/SoCalGas Systems we don't even have nominations to end-use delivery points, and the nominations on the PG&E system are arbitrary and do not bear any direct relation to actual or expected consumption.

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

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

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

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

I think in looking at these questions I appreciate that you recognize the limitation on the validity of the information that is typically available to LDCs on scheduling to end-use facilities, and these questions ask, don't you have some operational need to have this information? Generally the answer is: No.

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

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

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

Our response is that our systems are designed and built to criteria defined by our State Commission, and we recover the costs of those facilities in rates paid by our customers, including transportation rates, paid by, among others, the 110 or so customers of the size that Order No. 720 inquires about.

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

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

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

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

That concludes my initial remarks. Thank you.

MS. COCHRANE: Thank you very much.

Mr. Young?

MR. YOUNG: Good morning. I am Robert Young. I am Director of Scheduling for Energy Transfer, and I wanted to go through some of the questions you had.

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

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

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

Then there's either a monthly, sometimes daily process that those gatherers would have with their customers.

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

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

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

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

But for the most part, the gas controller will look at it and he'll tell you on a 5:00 p.m. in San Antonio in the summertime, 5 o'clock your linepack is going to go down because everybody comes home, turns on their air conditioners so the LDCs pulling all the gas off the pipe. But they manage that throughout the day, and that's where they have the 24-hour nom. They'll pack the line, try to stay within the parameters and everything kind of works.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

And at those points, at such points pipeline will post such 10-day nonconsecutive average peak flow as capacity. So rather than a design capacity, that would become your capacity. You would compare that to your scheduled record that are nominated every day.

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

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

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

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

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

And I think that covers everything.

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

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

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

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

Pipeline no-notice service, or in some cases on-system assets--for example, line pack and in a few cases storage--are used to supplement or balance the difference between what is received and what is delivered--which is the market demand. This is essentially how LDCs "back stop" the system.

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

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

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

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

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

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

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

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

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

Nevertheless, in most cases an LDCs do not require a nomination to a delivery point because (1) the customer's physical location is not going to change; and (2) the customers may be pooled for nomination purposes with other customers that are served by the same supplier.

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

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

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

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

Finally, many utilities use SCADA systems to monitor system flows and have OFO authority to tighten transportation service flexibility if it becomes necessary.

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

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

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

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

Thank you, very much.

MS. COCHRANE: I just wanted to clarify for Mr. Ellis why I asked that question about city-gate. In your Rehearing Request you suggest that posting could be at the interconnections with the interstate or at the city-gate, and I just wanted to clarify that that means two different things. That your city-gate is not at the interconnection with the pipeline.

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

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

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

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

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

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

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

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

MS. SHAHAN: It's one of them.

MR. REICH: --your main pipeline--

MS. SHAHAN: Um-hmm.

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

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

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

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

MS. SHAHAN: Yes.

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

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

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

MR. REICH: You anticipated my next question.

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

MS. SHAHAN: Again there's the two different worlds at Nicor. There's the SCADA control room that's watching the pressure and making sure everything is copacetic, working. That is really behind the scenes of what transportation customers are doing and what they're scheduling.

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

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

MS. SHAHAN: Correct.

MR. REICH: And with SoCal?

MR. ELLIS: Same situation.

MR. REICH: Chris?

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

But generally what would help us understand is that--I mean, some of you have large--you have generated assets on your systems. They can consume 85 million to 170 million a day at typical 7000 heat rate combined cycle plants. These loads can change quickly depending on weather conditions.

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

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

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

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

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

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

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

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

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

MR. REICH: Can I follow up?

MS. COCHRANE: Mike would like to--

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

In the operating world, you are probably going to have a communication from the operator of the electric facility to the gas control room, hey, we're going to be on in a few hours. It has nothing to do transactionally; it's just the load is coming on. So that is going to tell the gas operator, start packing the system.

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

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

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

Then as things happen, you know, that estimate assumes they're going to be able to cover everything with their line pack. They've got enough for the day to cover everything.

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

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

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

And then on a daily basis, the gas control centers work with each other to make that happen.

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

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

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

So whatever flows to that ultimate delivery is allocated to a customer. So they'll have a pool of all of their gas. So if they have 100 meters, those 100 meters all aggregate to one customer. So the customer then can schedule that one number, and the LDC's responsibility is just to make sure the deliveries get there.

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

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

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

So it is still an end-of-the-month issue. And as far as every day, we are looking at there's lots of forecasting that goes on. Constant forecasting and revising the forecasts because of the weather as much as any other volatility. But market demand can also, and supply operations or force majeure can affect those too.

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

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

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

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

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

Well then my response could be: Sure, but you need to nominate more for tomorrow because I can't prop that up. And that's where the nomination process at the mainline delivery point would happen. They would identify the people who were overpooling. They would have secure transportation on our pipes so that tomorrow that nomination could be 140 to meet that pool, or maybe 160 to meet the pull of 140 so that I can get paid back for the gas they pulled yesterday.

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

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

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

MR. PETERSON: If I could follow up with comments, Mr. Novak and Mr. Young, you both just made then, it seems to me in the comments that have been made there may be challenges in terms of disclosing on a daily basis information that might be customer level on networks for your companies or your members, but what I'm hearing though is ultimately on a monthly basis because of invoicing, because of billing, you do know ex poste at least how much you are delivering to your customers in situations where you don't know day to day, but because of the monthly billing cycle you do ultimately know that. And that information is available to you.

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

MR. NOVAK: That's correct.

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

MR. PETERSON: Right.

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

MR. PETERSON: Right.

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

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

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

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

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

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

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

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

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

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

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

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

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

MR. YOUNG: Well, there is a variety, and when you talk -- you know, you hear the word, "pools" or "aggregation points," and I think the issue that most people have, is the level of detail at either the initial upstream wellhead point, or the final downstream delivery point.

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

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

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

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

But if we have a point where we're aggregating hundreds of meters, we have one set of pipelines where gas comes in, it's purchased; it's all at a -- there's really not a nom, because we just know what we do, estimates of what we think is going to be out there, but we don't really nominate this gas that we're buying.

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

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

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

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

I think I would begin by saying that we look at what information is of value, that you've got posted information at a level that we believe is of value.

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

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

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

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

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

The example that's given at the end, for example, in overseeing markets, the Commission routinely checks for unused interstate natural gas pipeline capacity between geographically distinct markets with substantially different prices, as a sign that flows may be managed to manipulate prices.

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

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

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

MR. ELLIS: Yes.

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

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

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

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

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

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

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

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

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

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

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

MS. COCHRANE: Thank you.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MR. QUINN: Thank you.

MS. COCHRANE: Oh, please go ahead.

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

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

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

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

I mean, don't quote me on that, but it would be a lot smaller, but the thing that we thought, was, you're going to capture the same data, the same, and, I would argue, more accurate data, with less meters, because then, when we go through the design, identifying what meters do we post, that's been a big question that we've had.

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

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

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

Then they can do that query pretty simply, and if it feels comfortable that that's correct, and then it's just a matter of some pipelines would have to aggregate those to the virtual points; some pipelines would not, because they don't have virtual points.

But they could --

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MR. YOUNG: Yes.

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

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

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

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

MR. PETERSON: And under the --

MS. COCHRANE: Bridgett.

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

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

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

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

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

MS. SHAHAN: Correct.

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

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

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

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

And at the end of the month, we figure out all their customers that are covered by their contract, whether it's just themselves or thousands, and coordinate, like, well, you had this much storage this month and you've ratcheted down to here, or you're up to here, and it's definitely a lag of knowing, of dealing with all the paperwork.

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

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

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

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

(No response.)

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

(Recess.)

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

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

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

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

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

I still believe there is still much that is vague about the Order, and there's some confusion on actually how to implement it. We are in constant talks with engineers, internally, on what does this mean?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Because there's no safe harbor in this Rule, there is potential liability, and because of that, our internal audit and our external audit, are going to want to get involved. This means we're going to have to develop SOCs controls, business processes; we're going to have to document those controls, to ensure that behind the scenes, even though, as we're reporting, that there's documentation from managers and from the people actually doing the work, that they've checked off the box and they're actually doing what they're supposed to be doing, and that they are verifying the numbers, as appropriate.

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

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

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

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

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

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

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

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

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

MS. COCHRANE: Thank you. Mr. Ellis?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

I would also note that we are speaking about SoCalGas and SDG&E as one EBB. PG&E's Pipe Ranger System is another. Those are systems that have been in place for more than 10 years. They have a lot of functionality, a lot of information that is already posted.

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

Thank you.

MS. COCHRANE: Questions?

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

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

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

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

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

Did that help?

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

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

Enogex, I believe the 150 days, based on these assumptions, based on a more simplified but using a virtual pool is probably doable. If you start looking at actual meters, or we could get information up on the web just like John Ellis has said, but it would be meaningless.

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

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

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

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

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

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

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

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

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

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

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

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

But the process issues in taking what some parties have currently and then transferring that into, you know, a publicly disclosable format, that is something we were trying to get more information on today. And we suspect that there's a lot of variability in terms of the capabilities of different parties to do that currently, as well.

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

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

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

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

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

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

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

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

You know, we don't really want to go there. We really want to provide the most meaningful information to facilitate the transparency that you all are looking for, and that the market desires.

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

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

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

MR. McCANDLESS: Um-hmm.

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

MR. McCANDLESS: We--

MR. PETERSON: And what information do you have now that you could bring to bear to provide the market with a clearer picture of--you know, the Oklahoma market is kind of a place where we do not have very good demand information, frankly. And so what exists already that would be ready to go that you could implement in a system that would shed more light on that?

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

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

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

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

So it is being monitored daily. We have got a lot of good information on a daily basis at the scheduling and contractual level. I think the struggle I have is, when you're looking to dive into--some of the rule speaks to the actual nature of the business, and I think the lady I think from Nicor did a good job of saying there's these two worlds. There's the nomination and contractual world where you're balancing contracts. And then there's the physical world that occurs underneath that that the gas control groups manage. And the two worlds sort of live in parallel and they balance. At the end of every month you try to get everybody into balance, but the rule is sort of saying we want to--what I hear you saying is you want to see what's going on at the scheduling level, that's where the market lives; but what's actually going on at the actual level may be different.

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

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

MR. McCANDLESS: It's based on the world primarily of virtual points where we identify the 150 or 200 wells--or not wells, but meters, or virtual locations that will have to be identified and have an engineer at this time to actually come up with a number, what that theoretical number is.

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

MR. REICH: Thank you.

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

MR. McCANDLESS: Right.

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

MR. McCANDLESS: That's correct. It's primarily on the receipt side. A lot of it is--you know, a 4-inch meter tube is sort of standard 4 to 6 inch on our system, it's sort of standard. If you could 15,000 through it, you know, you may have a well that comes on, and again the way the decline rates work, you may have a well that may come on and the very first day produce 15- or 18,000, so you see the meter run for that size, but very quickly, inside that month, and then from that point forward for the rest of the life of that well, it's going to produce significantly less than that 15,000 a day meter. It will produce, you know, 1,000 to 2,000 a day. And again, we would like to avoid having to report--I think in reporting it, it is just going to be superfluous information that you would otherwise get. I think you would get more accurate information if you got it at the virtual point.

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

MS. COCHRANE: Any other questions?

(No response.)

MS. COCHRANE: Okay, thank you.

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

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

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

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

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

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

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

At this stage of the proceeding, we do have a Final Rule. We have Requests For Rehearing that are already filed. We are in the Rehearing stage. So it was not the intent to get more proposals. However, you know, the Commission wants to make this work and we want to have a rule that works.

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

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

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

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

(Nods in the affirmative.)

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

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

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

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