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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Regulation of the Purchased Gas Adjustment Clauses Contained Within the Rate Schedules of Columbia Gas of Ohio Inc. and Related Matters.	)	Case No. 04-221-GA-GCR
In the Matter of the Regulation of the Purchased Gas Adjustment Clauses Contained Within the Rate Schedules of Columbia Gas of Ohio Inc. and Related Matters.	)	Case No. 05-221-GA-GCR

THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
NOTICE OF FILING DEPOSITION

Pursuant to Ohio Adm. Code 4901-1-21, The Office of the Ohio Consumers' Counsel gives notice of filing the deposition of Scott D. Phelps, which was taken on October 17, 2006.

Respectfully submitted,

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Consumers' Counsel

Larry S. Sauer, Trial Counsel
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CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Ohio Consumers' Counsel's Notice of Filing deposition*, was served via Electronic Mail, this 12th day of December, 2006.

Larry S. Sauer

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of: :
: Case No. 04-221-GA-GCR
The Regulation of the :
Purchased Gas Adjustment :
Clause Contained Within :
the Rate Schedules of :
Columbia Gas of Ohio, :
Inc., and Related Matters.:

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In the Matter of: :
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The Regulation of the :
Purchased Gas Adjustment :
Clause Contained Within :
the Rate Schedules of :
Columbia Gas of Ohio, :
Inc., and Related Matters.:

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DEPOSITION

of Scott Phelps, taken before me, Rosemary F. Anderson, a Notary Public in and for the State of Ohio, at the offices of Columbia Gas of Ohio, 200 Civic Center Drive, Columbus, Ohio, on Tuesday, October 16, 2006, at 11:03 a.m.

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APPEARANCES:

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On behalf of the Residential
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On behalf of Columbia Gas of Ohio

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Public Utilities Section
By Mr. John Jones
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On behalf of the Staff of the Public
Utilities Commission.

ALSO PRESENT:

Columbia Gas of Ohio:
Mr. Thomas J. Brown, Jr.
Mr. Larry Martin
Mr. Michael Ripley

Ohio Consumers' Counsel:
Mr. Michael Haugh
Mr. Bruce Hayes
Ms. Tessa Parsons

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Tuesday Morning Session,
October 16, 2006.

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STIPULATIONS

It is stipulated by and among counsel for the respective parties that the deposition of Scott Phelps, a Witness called by the Ohio Consumers' Counsel under the applicable Rules of Civil Procedure, may be reduced to writing in stenotypy by the Notary, whose notes thereafter may be transcribed out of the presence of the witness; and that proof of the official character and qualification of the Notary is waived.

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SCOTT PHELPS

being by me first duly sworn, as hereinafter certified, deposes and says as follows:

EXAMINATION

By Mr. Sauer:

Q. Good morning, Mr. Phelps. My name is Larry Sauer. I'm an attorney representing the Office of Ohio Consumers' Counsel.

Have you had your deposition taken before?

A. Yes.

Q. Then you're probably familiar with generally the rules that are -- we play by here. I'd ask that you listen to my questions and then respond, and I will let you respond, and we won't talk over each other so the court reporter can take everything down.

You can answer "yes" and "no" to questions and not "un-uh" and "uh-huh" so it will be easier for her to get down and us to read later.

You're required to answer all of my questions unless your attorney instructs you specifically not to answer the question. If he objects, the objection will be dealt with at a later time by the attorney-examiner.

If you need to take a break, let me know. I just ask if there is a pending question, you answer the question and then we will break.

A. Okay.

Q. Can you state your name and business address?

A. My name is Scott Phelps. I work at 200 Civic Center Drive, Columbus, Ohio 43215.

Q. And what position do you hold with Columbia Gas right now?

A. Director of gas management services.

Q. Who do you report to?

A. I report to Mike Watson.

Q. What is that person's title?

A. Mike is the vice president of energy supply services.

Q. And who reports to you?

A. I have three direct reports, Rich Smith.

Q. What's Mr. Smith's title?

A. Manager of trading. Tom Heckathorn. Tom's the manager and contracts and scheduling.

The third person is Katie Reed. Her title is manager of gas purchase services.

Q. And, generally, what are your responsibilities as the director of gas management services?

A. I'm responsible for procuring the gas, entering into supply contracts, and buying spot purchases, making off-system sales, releasing capacity, scheduling that -- having that scheduled on the interstate pipelines, and reconciling month-end invoices and billings.

Q. Are you providing these services for Columbia Gas of Ohio only or for other Columbia affiliates?

A. No. I provide these services for the five Columbia Gas titled distribution companies.

Q. And if you could, which distribution companies are those?

A. Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Kentucky, Columbia Gas of Maryland, and Columbia Gas of Virginia.

Q. And you work for Columbia, or are you technically working for NiSource?

A. I work for NiSource Corporate Services.

Q. How is your time allocated to Columbia Gas of Ohio?

A. When I'm working directly on a particular LDC's work, requirements, I direct bill that, or, in other words, on my time sheet I put those hours in for that company. All other time is allocated on a preapproved methodology.

Q. Roughly on a percentage basis do you know what your time -- what amount of your time goes to Columbia Gas of Ohio?

A. It's quite aways the largest company, probably 60 percent, probably more than half, anyway.

Q. Does that allocation percentage fall pretty closely to the supply of gas among the different affiliates, or is there some measurement that coincides with that percentage?

A. Not in terms of the direct billing, but in terms of the allocation, it does.

Q. You said one of your functions is off-system sales.

A. That's correct.

Q. Can you describe for me what is off-system sales?

A. Well, technically it's defined in our stipulation, but it is what we can refer to as secondary market activity using capacity and supply to -- and selling that product upstream of where we would normally sell gas to our distribution customers.

Q. And what time periods do you typically enter into off-system sales transactions? Can they be hourly, daily, monthly?

A. Quite a wide range. They could span -- a product could span one day up to several months.

Q. What authority do you have to enter into those off-system sales transactions?

A. Could you be more specific about that?

Q. Do you have authority to enter into each and every one of the off-system sales transactions you engage in, or do you at a certain level of transaction have to get approval from the vice president of energy supply services?

A. I have authority to do it, to enter into the transactions. I do provide regular updates to the vice president of that activity, and the parameters are, say, constrained by our portfolio of assets and demand. Once we serve other core market requirements, if there's other assets available, we have the latitude then to use those assets.

Q. And what do you mean by "core customers"?

A. Well, we have obligations to serve Choice balancing requirements, Choice peak day requirements, the GCR customers, and, to some extent, stand-by service customers and transportation balancing. I think that pretty much covers it.

Q. And are these the upstream customers you're referring to?

A. All those customers I just talked about are distribution customers.

Q. Distribution. And in a previous answer you mentioned something about upstream customers.

A. I believe you asked what are off-system sales. Is that what you are referring to?

Q. Yes, what are the upstream customers you were referring to.

A. I don't remember referring to upstream customers, frankly, but if you can remind me what that was, I'll be glad to answer you.

Q. You said you sell to customers upstream. What do you mean by upstream? Are those city gate, or what do you mean?

A. Upstream. When I said upstream, from where we would normally sell the gas. By definition that's the distribution customer's meter. So technically upstream could be anywhere from the Columbia Gas of Ohio receipt point from an interstate pipeline to someplace in Texas or Louisiana, for example, where our capacity assets may begin.

Q. How do you know what capacity or commodity is available at any point in time, whether they would be eligible for an off-system sales transaction?

A. We keep good records of what we've done with our assets and what the demand of the customers is going to be at any given point in time.

Q. Are there specific reports that you rely on?

A. On a very short-term basis we rely on a morning report that's called the Gas Operations Outlook. It spans five days, I believe, beginning with the current day. It includes things like forecasted temperatures and demand, a general balance of the system.

Q. Okay. So that's a very short-term look at what's available for off-system sales.

A. Uh-huh.

Q. Is there a report or activity that you engage in to determine if you have the opportunity to do longer term off-system sales?

A. Well, when it comes to something that might be done with the assets, which could be a capacity release also, we're looking at our peak day demand forecast as well as the assignments or elections of Choice marketers to determine unused asset capabilities.

We run monthly send-out reports.

Q. What are those?

A. It's an econometric modeling of delivering gas to our GCR market. The end result is how best to deliver that gas to the GCR market. Those are reviewed monthly for upcoming months and seasons.

Q. And are those reports a span longer than the one-month period?

A. Not so much reports as they are runs from a model. And, I'm sorry, I didn't hear the rest of your question.

Q. What time period do you run these models for?

A. Specifically, normally the specific detail is for the following month, but an entire season is normally taken into some consideration, a summer season or a winter season.

Q. And do you know what park, loan and exchanges transactions are?

A. I know generally what the definition is, yes. I mean, I know what I think they are.

Q. What do you think they are?

A. They're all part of the same family of products. A time exchange is synonymous with park or loan. A location exchange is something different. But I'll assume we're talking about time exchanges, and it's when gas is received by one party and delivered to the counterparty at a later time.

Q. What would Columbia's -- first, does Columbia engage in park, loan and exchange transactions?

A. On a limited basis we do.

Q. And what would Columbia's role be typically in that transaction you just described?

A. We would identify a volumetric -- an unused volumetric capability in our portfolio and approach a counterparty with an effort to enter into a transaction with them for a fee that they would pay us.

Q. How are the revenues accounted for?

A. Revenues are defined as off-system sales revenues by the stipulation.

Q. Do you know approximately what percentage of Columbia's off-system sales in 2005 would have been related to park, loan and exchange transactions?

A. It varies year to year, depending on changes in the market, changes in our capabilities. You're just talking about off-system sales; you're not talking about the combination of off-system sales and capacity release, which was the sharing mechanism. I want to make sure I don't give you the wrong number here.

Q. I want to make sure I understand. The sharing mechanism is based on both off-system sales and capacity-release revenues; is that correct?

A. That's correct.

Q. And park, loan and exchange transactions are only off-system sales, or can they be capacity release as well?

A. They are part of the off-system sales half of that.

Q. Okay. So, just asking as a percentage of those off-system sales numbers, just the off-system sales piece, if you know, what percentage of off-system sales?

A. Probably 20 to 50 percent.

Q. Have you run into a situation where as a result of there being an off-system sales transaction, due to a change in weather conditions or something, what was thought to be excess capacity or commodity turned out to be capacity or commodity you needed to serve core customers? Have you run into circumstances like that?

A. I can't remember any specifics. It may have happened. Not recently.

Q. In an event such as that, what would Columbia's process be to replace the commodity or capacity that had been part of an off-system sales transaction that was subsequently determined it was needed to serve the core customer need?

A. What would be our reaction?

Q. Yes.

A. If it occurred, we would serve the customer by procuring gas, or normally -- that's the end of that question --

Q. On the spot market.

A. -- the end of that answer. Yes.

Q. That would typically be it.

A. Yes.
Q. That typically would be at a higher price probably than this commodity or capacity would be released at.
A. There's no way of saying that.
Q. A little while ago you mentioned the sharing mechanism that was part of the 2004 stipulation. That was discussed earlier today in Mr. Brown's deposition.
A. Yes.
MR. SEIPLE: Are you talking about 2003 or 2004?
MR. SAUER: I think it's probably a 2003 stipulation that was approved by the Commission in 2004.
A. So you're talking about the sharing mechanism that's currently in effect.
Q. Yes. What's your understanding of the sharing mechanism?
A. Revenue from marketed capacity releases and off-system sales transactions over the course of time are accumulated. If in the calendar year $25 million in total is exceeded, a sharing mechanism begins at 50 percent based on current Choice

participation, and prior to 25 million, the company retains those dollars in part to offset the capacity costs of the Choice program.

If Choice were to grow, the company's share of revenue above $25 million steps up in a series of four or five ratchets.

Q. Do you approach off-system sales differently for Columbia Gas of Ohio if the $25 million threshold has not been achieved yet versus if you hit the 25 million?

Let me rephrase that again. Is Columbia Gas of Ohio's goal to achieve as much off-system sales revenues as can be achieved?

A. As long as we are meeting our other goals at the same time, yes.

Q. What other goals might conflict with the goal of achieving max off-system sales capacity revenues?

A. Reliable economic service to our GCR customers, meeting the balancing requirements of Choice and transportation markets on the system.

Q. Previously Mr. Serio marked OCC 1 a 12-page document with attachments labeled Reply Comments of the Office of Consumers' Counsel. Do you

have that in front of you?
A. I believe so.
Q. If you look at Attachment A, page 2 of 3, line 11 speaks to sharing mechanism on off-system sales and capacity release, and line 12 is actually capacity release, and then 2005 has a $14.8 million revenue number. Do you see that?
A. Yes, I do.
Q. Did you participate in preparing this document in any way?
A. I don't recall participating in creating this document.
Q. Okay. Do you recall providing projections from 2005 through 2010 for capacity-release revenues?
A. Generally, yes, I recall working on that sort of a forecast. I don't know if it was in this time frame, but, yes, I have done that.
Q. Do you have any recollection of what volumes of capacity release would have been associated with the revenues that are listed in 2005 through 2010?
A. Normally on a forecast like this, the amount of capacity release is related to the level of

Choice participation on row 1.

Q. Can you explain that a little more?

A. Yes. As participation grows, the amount of the 25 percent portion of capacity costs that we are exposed to as COH also grows, and the assumption is that if that grows, capacity release will increase revenue-wise and off-system sales will decrease.

Q. Was there any consideration within the stipulation as to how to address a decrease in Choice participation?

A. The stipulation sharing mechanism, I believe, goes from zero to 50 percent or something when it comes to the sharing mechanism, and maybe that's how it's contemplated. Maybe I'm not getting your question.

Q. Okay. Well, the Choice participation on line 1 between 2005 and 2010 fairly dramatically increases.

A. Okay.

Q. Was there any contemplation as to how that might be addressed in the stipulation if Choice participation levels decreased?

A. I don't know.

Q. Going back to the capacity-release

revenues, you say they were somewhat tied to the level of Choice participation.

A. I believe that's true, because in forecasts like this one, that's the way it's been tied together, and I see that that's happening in this one by looking at those two rows.

Q. And do you have any feel for what quantity of capacity is being released in order to achieve 14.8 million in revenues?

A. Not really, no.

Q. Similarly, did you participate in providing forecast data for the off-system sales revenues that were shown here between 2005 and 2010?

A. I may have been involved in that. I don't recall.

Q. Do you have any recollection of what quantity of capacity or commodity may have been involved in the off-system sales transactions that would have yielded $16.4 million in 2005?

A. No. It's unlikely that off-system sales is forecasted on a volumetric basis. It's more likely it was based on historic experience combined with changes in Choice participation.

Q. Based on your familiarity with off-system sales, how does $16.4 million in 2005 compare to what Columbia had experienced, say, in 2003 and 2004?

A. I don't remember.

Q. Well, between 2005 and 2010 it's a pretty -- $16.4 million in 2005, 16 million the rest of the way out. Is that pretty consistent with what you've experienced prior to 2005?

A. My recollection is we were probably above that number in capacity release, may have been below the numbers that are appearing on here historically, but I'm not sure what those numbers were.

Q. And you seem to indicate that the higher the Choice participation, the more opportunity for capacity release; is that what you were telling me?

A. Yeah. I believe that's the likely reason why it moves from 14.8 to 18.8.

Q. So with lower participation levels, you would expect the capacity-release revenues to be less.

A. This is -- this is a forecast model approach. What happens in the marketplace is different from what I might forecast, so what I might expect, this is a best -- these are a series of assumptions about we got more capacity. It's also an assumption that the market value of that capacity stays at older levels, doesn't go down, so there's a lot of unsolvable or unknowns to the equation.

The assumption is that those other variables do not change your basic assumptions. Your basic assumption is that if we have more capacity to release, capacity release, two things happen when we have more participation. Our risk in terms of the capacity costs goes up, and the capacity we have available to release to mitigate that cost goes up, and that's what the 18.8 I believe is showing.

Q. 14.8.

A. Well, the rise from 14.8 to 18.8 is an effect, in part -- an effect of Choice program costs going from 125 to 165. It's two sides of the same coin.

Q. Are you familiar with any similar sharing mechanisms that may be in place in Columbia of Pennsylvania or Columbia of Kentucky, Maryland or Virginia?

MR. SEIPLE: I will register an objection for the record, not relevant.

But you can go ahead and answer, Scott.

A. Yes, I'm familiar with all Columbia

off-system sales and sharing mechanisms.

Q. Can you briefly describe what is in place in Columbia of Pennsylvania?

A. Yes. Columbia of Pennsylvania's mechanism is similar in some ways to Ohio in that off-system sales and capacity release, including exchanges, are tied into a uniform program, a single program. There is no Choice capacity cost risk in Pennsylvania, and the sharing mechanism that is currently in effect is 25 percent of the first $3.5 million goes to the CPA, and 30 percent of that number goes to CPA.

MR. SEIPLE: You might want to explain your abbreviation, CPA.

THE WITNESS: Columbia Gas of Pennsylvania is what CPA means.

Q. So it's 25 percent of the first $3.5 million, 30 percent of all revenues above 3.5.

A. That's correct.

Q. And the balance, the 75 percent under 3.5 million, goes to the GCR customers.

A. That's correct. And to the extent Choice customers do not elect capacity, that's not -- that cost is not picked up by Columbia of Pennsylvania.

Q. You said to the extent that Choice customers do not --

A. Do not elect to take our capacity under assignment, then in that case, the company, Columbia of Pennsylvania, is not subject -- does not assume that cost, as it does in the Ohio program. It does not book that as a cost on the bottom line.

Q. So who's responsible for it?

A. To the extent that occurs, that capacity could get released and it's part of the 75/25 sharing outcome. It's not tracked.

Q. What about Columbia of Maryland?

A. Columbia of Maryland has a two-part program. Capacity release is a program and off-system sales is a program. I might not get every one of those dollar amounts right, but I'll tell you my recollection.

The company gets 10 percent of the first $100,000 of capacity release and 20 percent over $100,000 of capacity release. In off-system sales, the company gets 20 percent of any incremental -- I'm sorry -- of any flowing transaction and 50 percent of any incremental transaction. That's it.

Q. Can you describe for me what is a flowing transaction?

A. Well, the Commission order says something to the effect of if the company uses incremental supply of capacity to facilitate the transaction, that's called incremental. If it's already -- flowing is essentially gas that is purchased for GCR markets and then sold. That's their definition. Again, there's no connection to the Choice capacity costs in there. It's a stand-alone program.

Q. So the company is not at risk for any costs.

A. Program costs, that's correct.

Q. And do most of the suppliers in the Maryland program take capacity from Columbia?

A. I don't really know the answer to that question. I don't remember. It's a very small program in a very small company.

Q. How about in Pennsylvania, are most of the suppliers taking the Columbia capacity there?

A. It's a very different Choice program, and they're only able to take FTS for a baseload, and I believe that most of them are taking that FTS.

Q. What exactly is FTS?

A. Firm transportation service as opposed to storage, is what I was trying to indicate there.

Q. And that's firm transportation service from the upstream pipeline.

A. Yes.

Q. And the description of the Columbia of Pennsylvania program, you said it's off-system sales and capacity release, including exchanges. What did you mean by exchanges?

A. I meant that in a similar fashion to Ohio, exchanges are part of the off-system sales definition.

Q. Can you explain what an exchange transaction is?

A. Yes. A time exchange is one in which one party delivers gas to a counterparty, and then at a later time, the counterparty delivers the gas to the original party at a different time.

Q. That's what you told me earlier; there were time exchanges and location exchanges.

A. That's correct.

Q. And those are all part of the park, loan and exchange then.

A. (Witness nods head.)

Q. Okay. And Columbia of Kentucky's

program.

A. Columbia of Kentucky has a uniform measurement of capacity release and off-system sales, and the sharing is a simple 50/50 split between the company and the customers, and there's no transition costs risk in Kentucky.

Q. And Virginia.

A. There is not a regulatory sharing mechanism in Virginia for Columbia Gas of Virginia.

Q. Is there a -- well, with those particular off-system sales and capacity-release transactions, do those revenues flow to the company 100 percent?

A. Could you repeat that?

Q. For Columbia of Virginia, are the off-system sales and capacity-release revenues retained by the company 100 percent?

A. Revenues, all impacts flow to the customers.

Q. So Columbia retains zero.

A. That's correct.

MR. SAUER: Off the record.

(Luncheon recess taken.)

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Tuesday Afternoon Session,
October 16, 2006.

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By Mr. Sauer:

Q. Mr. Phelps, we had just broken for lunch. We were kind of talking about the different sharing mechanisms that were in place in the different Columbia jurisdictions, and if you got an upstream customer who would be served from different Columbia affiliates, how would you decide which affiliate would get credit for an off-system sale or a capacity-release revenue?

A. First of all, everything we do by contract for each individual LDC, I mean every purchase I make, every capacity that I use, those are all LDC-specific, so when we're using an asset of some type, it's very clear whose asset that is. If there's available gas to sell, I know whose that is. If there is capacity to release, I know.

We don't do any business as a combined entity so we have all five tracks running simultaneously and individually for each company. I mean, that's my primary response, I guess. I mean that's the key point, I think. And each of those

LDCs has its own position in that portfolio in terms of serving its customers, in terms of how cold it is, in terms of what we're doing each day. So there's not -- it's clear to me when we have an asset to sell, I mean, whose asset it is.

Q. So there isn't a situation where you're operating, for example, Columbia of Ohio and Columbia of Pennsylvania as a single entity for any purpose.

A. That is correct.

Q. Does it become less clear if it's Columbia of Ohio but it's assets that would -- let me ask -- back up and ask a different way. Do you engage in off-system sales transactions with capacity or commodity that would be owned by a Choice supplier?

A. Do you use somebody else's assets to make an off-system sale?

Q. Is that possible?

A. I don't think that's possible.

Q. Okay. The Choice suppliers that have taken capacity or commodity from Columbia may engage in their own off-system sales transactions.

A. They're marketing companies. I assume they're transacting business in upstream markets.

Q. But they aren't taking their full -- they aren't serving their full customer load with Columbia assets; is that correct?

A. With assigned assets?

Q. Yes.

A. As a rule, that's true. There's probably some that do, but some don't.

Q. Okay.

A. They're somewhere between 75 and 100 percent of what they need is coming from us through an assignment.

Q. Okay. And then those -- the balance of assets that aren't used, for example, if there's 25 to 50 percent of their capacity not used by Columbia capacity or commodity, those are assets that would be available for Columbia of Ohio to engage in off-system sales or capacity release transactions; correct?

A. You said 25 to 50, and I'm not sure what you were referring to with those two numbers.

Q. I thought those were the numbers you gave me that they are using --

A. Well, I said they're taking 75 percent to 100 percent, whatever they need from us, 75 to 100.

Q. That 25 to zero balance then, those assets.

A. Those assets they did not take assignment of, those are mine.

Q. Okay.

A. So that would be part of what we're using to do off-system sales and capacity release.

Q. Do you have any sense of what percentage of your off-system sales may be derived from the utilization of those assets?

A. Not specifically. A very large part of capacity release, just in general terms, a big part of capacity release and a material part of the rest of off-system sales, I don't try to, you know, I don't have that all labeled, for example, in the system or something.

Q. Okay. I think, as you said earlier, as the percentage of Choice decreases, then your availability to do off-system sales increases.

A. It's a general theory based solely on, you know, being a bigger company, being a bigger buyer of gas, as a small LDC would be -- maybe have off-system sales -- a big LDC would have more off-system sales than a small LDC. It's based on that concept.

Q. How did you consider the off-system sales that were -- the revenues that were derived from the off-system sales transactions in November and December of 2004, from your perspective, were they to flow entirely to Columbia of Ohio?

A. That's really not my area of expertise. I would defer that to either Larry or Tom Brown.

Q. How do you alert potential buyers of Columbia's excess capacity or commodity that might be available for off-system sales transactions?

A. For capacity we have a very extensive list of potential buyers of capacity. Specifically we fax out notices to them describing the capacity that we are taking offers on, or we're running, for example, an RFP, and they have a time line to respond by and so forth, and they do that. There's probably more than 100 names on the list of companies.

Q. And that's all done by faxing?

A. That's how it starts. That's how it starts.

Q. Okay.

A. And then they will send their bid in, and then, you know, through telephone and things, we'll wrap things up afterwards, and those things get posted on the pipelines system, scheduling system. Any pipeline has a scheduling system, and we post that on there, and follow those, say, FERC and pipeline rules from that point in terms of, you know, their process of actually awarding the capacity to the counterparty.

With off-system sales it's different. We are essentially dealing with wholesale marketing type companies, and we're calling them on the telephone.

Q. Now, is that outside of the normal fax notice you talked about earlier? There may be situations you pick up the phone and call?

A. It's completely different. The fax notice is capacity release, and the last I said was the off-system sales.

Q. Commodity?

A. Off-system sales products, including things like the exchanges we talked about, but there's a clear distinction. Capacity release is capacity release. It's nothing else, and it goes through the pipeline, and there's a contract awarded according to the pipeline's tariff and all that. It's very specific, and you know what you're doing.

You're subletting your capacity.

Q. Okay. And that release, it can be recallable if you need it --

A. Yes.

Q. -- or once you let it go, it's gone?

A. No. We have both kinds. We determine what it is we're marketing. If we don't need it back during the time frame of the contract, it's nonrecallable. If we may need it back, it's recallable.

Q. Now, I know we had talked back and forth about off-system sales and capacity releases, and I asked you some earlier questions about off-system sales, and I will ask similar questions about capacity release. I don't know, in your previous answer you may have assumed it was the same for whatever reason.

A. Okay.

Q. The time frames for gas release transactions, are they typically a longer-term transaction, or can you have short-term capacity release transactions?

A. Up to a point they're both. A release transaction -- release transactions less than a month

in duration are rare.
Q. Okay.
A. There's probably a couple of them out there, but for the most part, capacity releases go either for a month or for a number of months up to, say, a year.
Q. Okay.
A. Or it could be a winter season or a summer season, that sort of thing.
Q. And I think we talked about the different modeling that you did or reporting options that you had available to determine how you know what was available for off-system sales. Is it similar for capacity release, how you determine what's available?
A. The planning process is used to help us determine capacity release availability, the amount we could release, and that also is done with the help of that product that I referred to, which is called send-out, and it comes out of our monthly planning sessions.
Q. And who is involved in the monthly planning sessions? Would that be Mike Anderson's group? Is this all internal to your organization?
A. Yeah. It's all of ESS and kind of a

cross-functional effort. It includes Mike Anderson, some of his planning people, me, a couple of my folks, my managers, Mike Ripley, they're all involved in that session. That's a pretty good description, I guess, of the group. Sometimes one or two more; sometimes one or two less.

Q. Okay. When you're focused on capacity release transactions, are there authority limits that you have if you want to enter into a capacity release transaction?

A. The plan coming out of that is, say, a mutual plan in the group, and it's something we have come to and kind of hammered out and agreed to, and it would include -- capacity is a limited thing, you know. You have a contract. We have a certain amount of it that's been removed for the Choice program assignments, and those are gone.

And we have other needs to serve daily swing needs on the -- basically balancing the system during that upcoming month and things like that. When all of that is said and done and we've applied the amount of gas we need to buy on the extreme days, then we know through the mathematics how much we might release. We can try to release it. It doesn't mean we can release it because the market doesn't necessarily buy it.

There are some times and some particularly with, I'll say, some parts of the portfolio that are just in some months too big for the market to absorb, our storage injection rights or something like that. There's more there a lot of times than we can sell, but we go out and try to sell that. So we'll identify a number, but that's not necessarily you will see what we sold because we just couldn't find that much market.

Q. So if you have more available, you'll sell it off in increments smaller than what you originally planned on releasing. Is that what you're telling me? It's not an all or nothing transaction.

A. No. There's multiple transactions to get to a total. If you have 10,000, you do 10 deals at 1,000 each or what the market will offer you.

Q. Okay. I think you described as one of your functions as the procurement of gas, one of the functions.

A. Uh-huh.

Q. What are your -- generally what are you procurement practices for supplying GCR customers?

A. Generally, we supply the GCR with a combination of firm short-term contracts and spot gas. Spot gas is purchased either one day, say 30 days at the time, in other words, one month or a single day.

Term purchases are negotiated each summer through a process that we run beginning in late spring, and we get multiple bids from parties related to different receipt points and months we want to purchase the gas. We'll buy more spot gas in the summer than we will the winter. From a reliability standpoint, we will, say, bulk up during the three coldest months of December through February with firm gas. We have a general approach that says we need -- we build the language in the contracts that allow us to swing down or not take the gas if we don't want it to add flexibility for different weather conditions and so forth.

We approach counterparties that we feel are good and capable on the systems where we need to buy the gas, that they have the kind of history and skill we can depend on. So usually there's a list of about, you know, 20 to 25 to 30 people involved or companies involved in the RFP. Typically that's for a 12-month period.

Q. So you rely typically on the RFP process.

A. Typically for the winter months, not the summer. Summer we are buying a lot of 30-day spot gas, and a lot of months through the shorter months, because of daily management of the system balancing that I referred to in terms of balancing the system, we have daily purchases as well, or we'll have daily purchases because, well, we're not quite filling up the storage to the point we wanted it to be at the end of the month so we are going to buy to stay on plan.

Q. And you referred to, I think you said, "term sales." Is that similar to baseload sales?

A. I probably said term purchases, not term sales. A term purchase, what I mean by that is it's got a contract, spans several months to a year, generally speaking, could be longer, but it's not just a 30-day deal. It's a more lengthy term. That's where I'm using that word, and it's labeled firm, and it's designed to meet the cold, you know, days of our customer demand in terms of volume. It's not necessarily related to baseload. If I trigger the purchase for January under that term contract, then, yeah, in January it's a baseload volume.

Q. Okay.

A. It's not the baseload for 12 months or something like that. It's got kind of first of the month flexibility generally, and in terms of zero -- in terms of it nominating from zero up to maximum daily quantity of the contract, and it also has the ability to swing up or swing down during the months. That doesn't come free. If you actually trigger those kinds of things at that point, then you get into keep-whole types of provisions with the contract.

Q. And keep-whole provisions are --

A. They reflect the difference between gas daily and first of the month, generally. I mean, the supplier expects and goes out and provides you with the first of the month supply. He based that on his first of the month index. He's tied it down, and you hit a warm weekend in November, and you can't take the gas. So he's at risk or he -- it goes both ways, but he's at risk for -- he has to go out and sell that gas.

Q. If he sells it at a loss, you pick up that difference.

A. That's right. That's right.
Q. Which ultimately gets passed back.
A. So we try not to overbuy.
Q. In that situation you said the supplier had sold it at a loss. That loss comes back to Columbia and then gets passed to the GCR; is that correct?
A. If that happened, yeah.
Q. And I think you had described purchases that might takes place in shoulder months. Can you tell me what those are?
A. Well, there's not a month that goes by that we don't buy some kind of gas. We are either serving the market or filling storage, so we're buying gas in the shoulder months as well.
The only -- what I'm -- I'm not sure what we were referring to, frankly, when we talked about shoulder months, but shoulder months are served by a combination of term and spot gas.
Q. What months of the year would typically be considered shoulder months?
A. Well, people would have different definitions of that, but I'm pretty much limiting my discussion to November and March right now.

Everybody has a different -- that's just where you come from, what you're doing. I'm distinguishing it from the three core months because we buy a higher level of term gas in the three colder months.

Q. Okay. When you're procuring gas, what would be the longest term for a transaction?

A. Recognizing this distinct -- this difference between -- let me ask you if you can describe that a little bit more, what you mean by the longest term of a transaction. Is it the furthest month into the future that we have a contract or something like that?

Q. Are you talking in terms of one-year contracts, two-year contracts, five-year contracts?

A. Almost everything I talked about so far is between three months and one year when we're talking about term contracts.

Q. Okay.

A. In some cases in the recent past we went out further than that by several months because of the aberration of a Columbia of Ohio hedging program. The way that program works, you may need to purchase or fix the price on some gas that's as far out as one and a half to two years out. That's really the only kind of interstate, long-term -- longer-term purchase we've made recently. I have, you know, some local gas contracts and stuff with, you know -- actually, those roll over every year now, too, so I guess you can say they're one-year contracts, too. I was off on the wrong track there.

Q. And what would be the shortest term of a transaction?

A. The shortest term of any transaction or of a term contract?

Q. Of any procurement transaction.

A. Any procurement transaction. One day may be -- depending on how you look at the way these things are recorded, we may buy halfway through the day so it's kind of an intraday.

Q. More of a spot purchase type purchase.

A. An intraday is unusual. That's more towards critical times when you didn't really have a good enough feel the day before. There's quite a few one-day purchases. It's just the way the market works. Typically the market is in a spot of either one day or 30 days. There's not a lot of four-day or seven-day deals.

Q. Within your organization has there been any discussion or studies done to determine if a wholesale auction could be undertaken to serve the GCR customer supply?

A. The only discussions have been reactions to what we've read and heard about the recent East Ohio Gas auction in terms of talking about that auction, not in terms of talking about Columbia of Ohio doing an auction. This is just general discussion.

Q. And what is your understanding of that auction?

A. Is it high or low? You want me to explain the auction? I don't have a great understanding of it. I have a general understanding of it. I know there were 12 tranches. That's the new word. There were 12 tranches, and there were some winning bidders.

Q. Is there any operational constraints that you're aware of that would preclude Columbia Gas of Ohio from conducting a wholesale auction?

A. I don't know yet.

Q. What type of analysis do you anticipate would be required in order to make that determination?

A. I doubt that I would be making that analysis. I'm not sure what would be needed to review.

Q. Is the auction terribly different than the RFP process that you've talked about going through to procure the supply of gas?

A. On the surface I can't tell, other than, you know, the brief bits and pieces I've heard, so I assume that there's considerable differences in terms of rules of delivery, the way capacity is treated, how the system is balanced, which I don't know how that's done with the East Ohio process, just to name a few.

Q. Do you know how much capacity Dominion reserved in order to meet their balancing needs?

A. No, I don't.

Q. And you're also responsible for the banking and balancing services that are provided.

A. No, I'm not.

Q. No?

A. I think we said that would be Heather, better talk to Heather about that.

Q. Okay. Are you responsible for monitoring and calculating the supplier's capacity that is mandatory under the 2003 stipulation?

A. Yes, my group is. I don't do that personally, but it falls under my responsibility.

Q. And you're familiar with the analysis that goes on to make sure the suppliers are appropriately taking the capacity they're required to take.

A. I'm familiar with the process.

Q. And do the suppliers have an opportunity to meet that requirement in different ways?

A. Yes.

Q. And what options do the suppliers have?

A. Well, they have -- they elect between two different kinds of balancing services. One does more in terms of balancing but also costs more, is a bigger contributor to their 75 percent requirement.

They have options related to how much firm transportation capacity they elect in conjunction with that. There are some -- there's an option, I believe, that they can elect Columbia Gulf to link up with Columbia Transmission, for example, there's some upstream optionality for them. And they get, to some extent, a chance to look at it throughout the year. They can't change everything all the time, but they can take more capacity to meet their needs as they go.

We get their information. We check it to make sure it's at least 75 percent and fit the requirements, and then whatever needs to be released, is released or assigned to them.

Q. So they can take it either through upstream pipeline or storage, or through banking and balancing, are those the two?

A. Yes. I neglected to mention storage, but I should have. I should have mentioned storage.

Q. Okay.

A. So we are talking about FT, storage and balancing services essentially.

Q. And what are balancing service credits; do you know?

A. I don't know. I'm not familiar with that term.

Q. Okay. I think the auditor on page 5-6, Exhibit 5-8 on page 5-6, they have balancing service credits going from November of 2004 through October of 2005. Do you see that?

A. I see the table, yeah.

Q. Okay. Do you know what they're referring to?

A. It appears to me it's an amount these marketers pay for these balancing services, but I'm not sure.

Q. Okay. That being part of what -- it helps them meet their required 75 percent capacity, those charges?

A. It appears that way, yes.

Q. Can the suppliers meet their mandatory capacity through any other Columbia service?

A. You mentioned storage and FT assignments and balancing. Not that I recall.

Q. Does Columbia place any parameters on the marketers regarding the mix of how much capacity and storage versus banking and balancing that they take?

A. The tariff is pretty specific about that, and I don't have it memorized, but, yes, there are limitations on storage. Some of those depend on which balancing service you select. They limit changes, in other words, on service depending on whether you select balancing service A or B. You're limited to something that has relationship to where your customers are located in terms of the delivery point site of the picture. In other words, you can't take it all in one market area. You have to deliver to the market areas where your customers are located, those kind of parameters, locational, and there's some FT limitations.

As I said, this is all specified very specifically, I think, in the tariff. I don't know what the words are.

Q. Okay. You say they do have some ability through the course of the months or the year to make a change to whatever they've selected.

A. Yes. They can make the kind of change -- I'm talking about if they're within their parameters, say they have 100 decatherms, and within that parameter they could take -- the rules would allow them to take up to 120 decatherms of that particular asset, and he comes in and says he wants 110 now. We would say okay and release that to him.

Q. Okay. Now, the Choice program costs that the suppliers are not responsible for, who's responsible for those costs?

A. Those Choice program costs related to the capacity that the marketer didn't take through the process we just described are the responsibility of Columbia Gas of Ohio, in my understanding.

Q. Okay. And then those costs are being recovered through off-system sales and capacity-release revenues; is that true?

A. Generally speaking, that's my understanding.

Q. And these program costs have been incurred since the beginning of the Choice program.

A. The very beginning of the Choice program, or the beginning of this stipulation?

Q. Let's take it in two parts. Since the beginning of the Choice program, there's always been program costs that have been the responsibility of Columbia; is that true?

A. I don't recall. I don't think that's always been true.

Q. And since the beginning of this 2003 stipulation, that program costs --

A. There's been program costs every month.

Q. And, to your knowledge, has the Commission ever conducted a hearing and evaluated the prudence of those costs?

A. I don't understand the question.

Q. Have those costs ever been reviewed by the Commission?

A. The costs that we incur and take the bottom line ourself?

Q. Yes.

A. I don't remember what all of the topics of the audits have been or what different subject matters have been related to that since 2004. You might ask Larry about that.

Q. If I could, I'd like to back up just a minute to some of the discussion we had about park, loan and exchange transactions. And I think you had talked about time differentiated exchanges versus location exchanges. Could you describe what a location exchange is?

A. A location exchange would occur simultaneously instead of at different times, so if there's -- the transactions I'll describe in a minute are all happening at the same time, and the difference is not the time that the gas is exchanging hands; the difference is the location at which the exchange is changing hands.

Q. So kind of a like-kind exchange?

A. Yeah, you could -- some people would call it that.

Q. And are there time-differentiated

exchanges that are not park and loan type exchanges?

A. I think -- well, I mean, park and loan, all that stuff is really defined by the person talking, and in my mind, they're essentially the same thing. I'm not going to say that everybody else that you ask that question of is going to give you the same answer because there's a lot of people in this industry, but I've described park and loan or exchange, and I've done it for both of them together, and one party gives gas at one time and another party gives it back another time. That applies to the loan or a time exchange.

Q. You're not aware of any facility differences necessary to accomplish those exchanges or any operational differences to accomplish those exchanges?

A. They can be done at different locations, which, you know, might entail different assets, depending on who's doing them. But whether you called it an exchange or you called it a park, I'm not drawing a distinction there. I would call them the same thing.

Q. Okay. Does location exchange have to take place the same day?

A. Does it have to? If it didn't take place the same day, it would probably be a combination of a location exchange and a time exchange. So that's a new -- so that's a third category.

Q. And you engage in those as well?

A. You just invented something.

Q. How many days -- if you have a situation where a transaction does not takes place in the same day, how many days could separate between the two exchanges and still in your mind be a park, loan and exchange?

A. How many days could -- would you say that again, because I'm not sure which product you're talking about anymore.

Q. I'm not sure I know anymore. You said there are -- potentially there could be a -- I think you were suggesting there could be a time and locational transaction taking place, a combination of the two.

A. It could happen. There's nothing that prevents it from happening. You raised the question I said, yeah, it could happen. It's a combination of the two of them. It's not just a location exchange. It's not just a time exchange.

Q. Okay. And as you separate, they're not happening simultaneously; you're getting some time in between the two transactions.

A. Uh-huh.

Q. Is there a limit of time that in your mind it would no longer qualify to fall within these types of transactions?

A. Well, you said the same thing. Which transaction? Can you give me one to talk about? I just want to answer you clearly. Just ask me one of them.

Q. If the transaction is more than one day, is it a park transaction or a loan transaction?

A. If it's not happening at the same day, it's either a time exchange, which you could call a park or a loan, or it's this new thing that you discussed, which is a combination of a time and a location. You didn't say whether the location was different in the transaction.

Q. Okay. So assume the location was different. How many days could there be between the transactions before you wouldn't consider it a park or a loan?

A. There is no number of days.

Q. There's no limitation?

A. Theoretically there is no limitation.

Q. Okay. Do you know what percentage of exchanges make up Columbia's off-system sales revenue?

A. I think I answered that one.

Q. What was that?

A. I said I was estimating between 20 and 50, probably.

Q. Okay.

A. It's a rough estimate.

Q. Do you know which off-system sales transactions generate the most revenue between park, loan, exchange and pipeline capacity release or regular off-system sales as well?

A. The value of the transactions are dependent on circumstances in the market. Sometimes any one of those that you've just said could be the most valuable of the four or five that you mentioned. It depends on -- it depends on the market and what kind of weather, supply/demand balance, all those things that occur.

Q. If you recall or know offhand, in 2005 what were -- which of these were more -- generated more revenues?

A. How do you -- I'm not sure how to measure that.

Q. Are there reports that your organization generates on a regular basis that identifies revenue streams and what amounts were received?

A. We record how much revenue is booked, for example, but your question is dependent on a lot of variables or interpretation. How many decatherms, how many transactions did it take to make that $3 million dollars versus the other way, this year versus last year. When you say which one is more valuable, I don't know what that means.

Q. Okay. Again focusing on just 2005, did you create a report in which you could identify there were so many million of off-system sales, so many millions of capacity release, so much for park, loan and exchange and itemize each of those items?

A. In that fashion, I would estimate the capacity release was the most valuable, but I'm estimating. It's right up there. Exchanges were probably second, followed by smaller pieces of the other flowing sales and so forth. But that will change. I'm trying to remember 2005. I don't remember exactly what it was.

Q. Okay. What's the report that you prepare? What's it called?

A. I'm just saying we have revenues that we booked, and we have a record of it. I don't have a report named for it.

Q. Which of the transactions that we have been discussing provide the greatest margin?

A. That's what I just answered.

Q. Okay. That's capacity release.

A. When I'm talking about revenue, I'm talking about net revenue; okay?

Q. Okay.

A. Same thing as margin.

Q. Generally speaking, what is it about capacity-release revenues that allow them to generate the most revenue?

A. The capacity release benefit is -- it comes in every day. It can be a relatively small amount of money on a daily basis, but it's happening every day, and with other products, they tend to be, you know, much less -- more sporadic, and, you know, not for a month at the time, not like for four months like I do a release.

So I would say, just generally speaking, that's the first thing about capacity release, the important thing is that it's revenue every day.

Q. And does Columbia release storage to customers?

A. Be more specific, please. We do release storage to Choice marketers.

Q. To Choice marketers.

A. Yes.

Q. And where would the revenues from that transaction, where would that fall?

A. That's part of this discussion and part of those revenues that relate to the marketer achieving 75 percent of the capacity costs.

Q. So that would fall in their capacity and storage charges.

A. Yes.

Q. Is that the only situation in which Columbia would release storage to customers?

A. We're not prevented from releasing storage, but I can't recall any other time releasing storage.

Q. You have discussed earlier Columbia's -- you mentioned the hedging program. Is that program under your organization?

A. Yes, sir.

Q. Can you kind of give me a general explanation of what the hedging program is?

A. Sure. The background is that the hedging program was initiated in 1998. It's had some small amendments over the years, but it's very much like it was then in design. It's a program -- it's a plan that initially forecasts GCR customer demand in a future winter period and then strives to lock in the price on a percentage of the gas that we will have to buy in that winter to serve that market.

So what I've excluded in that sentence is withdrawals from storage. It's not in this calculation. So when I say 50 percent, what I mean is 50 percent of the gas that we would plan to buy in the November through March cycle, not 50 percent of the total amount that our customers will burn because that would include storage withdrawals. So the plan is intended to mitigate the risk related to winter price spikes in the market.

The second part of the program, the second step is we calculate trigger prices pursuant to the language of the plan. It's very specific. We calculate trigger prices at which we will go out and lock in those future prices for a specific amount.

So in the end what we have is five trigger prices and five volumetric bands that each relate to 10 percent of that volume I said we were going to buy in the winter. If we don't reach a trigger price; that is, if the trigger prices are based on the winter strip NYMEX price, that's what we're monitoring there.

If the winter strip reaches a trigger price, falls to a trigger price, we will lock in that 10 percent of the volume, and we will do that with a physical gas contract. We will call one of our suppliers with whom we have contracts, and, in particular, this hedging process, and lock in the prices based on the NYMEX for that future winter period that occurs that day. We do not enter financial contracts ourselves.

If we get to the summer just prior to the future winter period and we haven't locked in at least 30 percent on our way towards that 50, if we haven't locked at least 30 percent, then the plan provides direction where we hedge in May, June and July to get to at least 30 percent so that at least that portion of the winter volume has a fixed price.

Q. If I understand what you're telling me, there's -- based on winter strip NYMEX, there is an historical number that is used to establish what you're calling trigger prices.

A. Yes. We do historic prices to calculate the trigger prices. I didn't go into a lot of detail on that, but that's what we do.

Q. Okay. And those trigger prices are a percentage of that historical --

A. Yes. Specifically we look at the window period of time when the NYMEX is traded at the future winter, and we average all those numbers in the winter period to say that's an indicator of what the market thinks that winter is like.

We also go back four prior winters for the previous four winters, and we average the final settle price of each of the winter months, so talking about 20 numbers, the final settle price for each month in the prior four years, so four years times five months. Each month has a final settle that's very much like an index price. It's created in the same time frame, the monthly index.

On the one hand I have the average of

those 20 months of actual history, and I've got this hundreds of numbers related to what -- how the market has traded this future winter period, and we give each one of those equal weight. We average it, creates a benchmark.

Triggers are actually percentages of the benchmark. So the five triggers are 85, 95, 105, 115 and 125 percent of the benchmark price. So all that description that I -- all that averaging and stuff, that was a description of how to get to the benchmark, and this trigger is simply that.

Q. And, again, you're at the point in time purchasing supply for the next winter only.

A. No. The plan -- the creation of these five prices is done at the beginning of each November. When we do that, we're creating or calculating those trigger prices for the second winter out. So at any time in our plan there's two winters that we're actively looking at. The next two winters are always, say, on the table for us in this plan. Come November one winter drops off, the winter you just entered, that winter drops off and a new one two years out is picked up. So the benchmark we're calculating for that winter two years out.

Q. Okay. So in November of '06, you'll be creating a benchmark for the winter of '08.

A. Yes, the winter of '08-'09.

Q. Okay. Are you looking at the trigger prices on a daily basis, on a monthly basis?

A. Whenever it hits a trigger, we need to act, and our plan is act whenever it hits that. You know, you can hit big stretches of time where you're nowhere near it, so you're not taking time out that day to go look at it necessarily because you're a dollar away or something. But in practice or in the way the plan works, anytime it gets down to the trigger, that's when we're acting on it.

Q. Okay. So if you are in a situation where the 85 percent trigger hits, then you have a volumetric band.

A. Yeah. We have a specific number of decatherms we are going to lock in at that time.

Q. Okay. And what are the bands that you're operating under?

A. Which band? Are we talking volumetric or dollars?

Q. Volumetric, yes.

A. Are you asking for a number or a

description of it, because I don't have the numbers? I don't have them in my head.

Q. Okay.

A. But those are the, you know, the volumetric triggers that go with each one of those things. Each one equals 10 percent of the gas to be bought in that winter such that if you triggered all five, you would be at that 50 percent number I talked about, which is the maximum hedge volume, the 50 percent, the minimum being 30.

Q. Let me see if I understand it. At 85 percent you have the same volumetric band as you have at 95 percent.

A. Yeah, they're equal bands.

Q. It's unlikely --

A. I'm not going to get to 85 until I've gone through all the others, most likely. It could start out day one and hit all of them, but to get to 85, naturally, it's going to show prices dropping and we're going to get there. I'll go through the 125 and do that. I'll go through the 95 and do that before I ever do the 85.

Q. Okay. With this volumetric band it's determining what physical gas contracts you're going to enter into.

A. That's correct. That's correct.

Q. You're actually buying supply.

A. Yeah. I want to add one thing to the size of the band; that is, that one of the things that is an additional aspect of the plan is because this is a physical hedge, we also put another parameter in the program, and that is related to the baseload in any of those winter months so that sometimes in the past our winter maximum has not been 50 percent of the total volume. It becomes some other number because it's limited by our baseload take capability, and it's likely to be in a month like November, for example, and so not every year has a 50 percent max. Some years have like 38 percent max or 46 percent max or something like that, and then we cut the volumes into five equal parts, but now it's 8 percent instead of 10 percent. It's one of the limitations of the physical hedge program.

Q. Is it dictated by how much storage is available?

A. What I just described?

Q. Yes, the limitations that come into play.

A. What I just described is, for the most part, limited by warm days in the shoulder months. Everything is related to the portfolio at some point, but I can't say it's a storage issue. It's just a baseload FTS issue, a baseload firm transportation issue.

So I want to point that out because that's a secondary limiter to the 50.

Q. You said that the supplier was then entering into financial contracts or --

A. No. Actually, I said we don't enter into any financial contracts. Whether he does or not is up to him.

Q. But Columbia of Ohio is not doing any financial hedging.

A. That's correct. That is correct.

Q. Now, once Columbia has entered into a hedging transaction, does Columbia hold that position until the delivery month, or is Columbia trading around those positions prior to their expiration?

A. No. The plan is to hold it. It's not a plan where I want to get in and out. It's a plan -- if it's for November of 2008, our plan is to flow that gas in November or March of '09 or whatever months we're looking at.

Q. And how does Columbia treat the gains or losses that come about because of these transactions?

A. These are all fixed price contracts so this is stated right in the plan. These are all GCR impacts.

Q. GCR effects?

A. Impacts.

Q. Impacts?

A. There is a decatherm of gas we are buying. It's a decatherm of gas we're buying in December of '06, and it costs X. It costs whatever we contracted for, and that is what we would report -- be booking towards the GCR.

Q. I thought the auditor had mentioned something about -- it's on page 6-2, top of the page. It says, "In 2004, 2005, the Plan" -- I think they're talking about the hedging plan -- "saved consumers $15,438,000." How as that determined?

A. How did he do that?

Q. Yes.

A. There was a -- well, it's up to him to say how he did it, but I can tell you how I think he did it. There were a couple of interrogatories -- in fact, we might have provided him this. I can't remember for sure, but it's a comparison against the monthly index, essentially. I mean, I can't remember if he asked us for that report or if he just asked us for the indices.

But there's a first of the month index for each one of these months in question. It's very close, if not the same as the price, or maybe it's been adjusted with bases in the report with his information, but he's equalized or made this purchase in Louisiana equivalent to NYMEX or equivalent -- I'm sorry -- equivalent to the first of the month indexes. I'm not sure offhand if that was the NYMEX index that some people report or the Henry Hub index, I mean, or if was that Onshore, Columbia Gulf or which index.

The point being, this is a comparison against basically what we were paying for our other gas that month or what people were paying for gas at that location that month for a 30-day purchase. He's just added up the totals, the total differences.

Q. Do you do something internally similar to that?

A. Yeah. Yeah. I believe we provided that somewhere along the road in one of the interrogatories.

Q. Did Columbia Gas of Ohio engage in any physical or capacity transactions with its affiliates?

A. Physical or capacity transactions? Of course, there's a lot of capacity with my pipeline affiliate that I have a long term contract with.

Q. How about the other LDC affiliates?

A. From time to time we have had some, but the answer is yes. I think there's been some of both, capacity release and some sort of off-system sale.

Q. And how are those recorded?

A. As off-system sales.

Q. Okay.

A. Or capacity release.

MR. SAUER: Is this a good time to take a break?

(Recess taken.)

Q. (By Mr. Sauer) In terms of off-system sales and capacity-release transactions, how are those revenues accounted for? Are they accounted for in the same month that they occur? Are they recorded the month the revenues are collected, or is there another method that's used?

A. Well, I'm going to defer to Larry on that. I have a fair understanding of it, but I don't know if I can answer that question.

Q. To the extent that Columbia projects off-system sales and capacity-release transactions, what circumstances could result in Columbia not achieving the level of transactions it anticipated?

A. Several things. You know, price of gas changes every day; in other words, based on the kind of year the industry has in terms of weather, volatility, all the things that impact that, if that puts -- that can easily put us in position where we need to either defer off-system sales because it's more difficult to serve the market, our market. That's our primary task. Or it's lack of volatility and maybe, for whatever reason, just doesn't create opportunity, doesn't create the margins. And so it's very difficult to predict, and it's difficult to -- it's difficult to predict what those variables -- which of those variables will occur this year and will we be in position when they do occur to make some kind of sale.

You know, a lot of our assets are most

valuable at times we need them.

Q. You said sometimes you may defer capacity-release transactions because it would make serving core customers more difficult. Is that what you said?

A. I was speaking generically about off-system sales or transactions in general, and saying that -- it came around to the same point again, which was when the margins present the best opportunity may not be the time when we have any assets, and when they present the least opportunity may be when we have the most assets.

That's actually fairly common in the industry, and it makes sense because it's driven by supply and demand. And when we need our assets to serve our markets and our balancing services and stuff, that tends to be the time when these would be most valuable, but that takes second place to serving this market.

With the volatility, the Choice participation could change, and that changes our opportunity in the future.

Q. As Choice participation decreases, your opportunities increase. Is that, generally speaking --

A. As I said, some opportunities go up and some go down. There's a theoretical point of view that says if the 25 percent grows, they'll be more capacity-release revenue, but there will also be more Choice program costs. You asked if it was easy to predict it, and I'm saying, no, it's not.

Q. When Columbia prepares a forecast similar to what we were looking at on exhibit, OCC Exhibit 1, Attachment A, page 2, there was a forecast for capacity release and off-system sales. Do those forecasts -- does this forecast in particular just reflect normal weather?

A. I don't know what that forecast predicts, Remember, I didn't even remember having a hand in it.

Q. Does Columbia ever take a prediction such as this and then look back to see where it was accurate, where it was inaccurate?

A. Would you point where the forecast is?

Q. Off-system sales revenue, lines 12 and 13.

A. Well, if we had actuals become known during the course of the year as you went through it, sure, we know how we would compare to something like that if we generated one.

Q. Do you know if they did in particular with this projection and what happened actually in 2005?

A. No, I don't remember the numbers.

Q. Would you look at the audit report on page 5-9?

A. Uh-huh.

Q. If you look at the exhibit on page 5-9, the off-system sales revenues in column G, do you see that?

A. Yes.

Q. And that time period is November 2004 through October of 2005. But if you remove the 12.9 million in November of 2004 and November of 2005 and December of '04, the ten months of '05 are somewhere around 105 million. Do you see that?

A. That's what he's got, yeah.

Q. Okay. How did that compare to what is shown on Exhibit 1 for off-system sales of 16 million?

A. This is gross revenue.

MR. SEIPLE: For the record, you need to indicate what you're pointing to when you say "this."

Q. Okay.

A. I have to say I didn't make this table, so I wanted to say that, too. In column F, cost is listed. What I believe the auditor has done with this particular table is ask us for those -- for off-system sales where we bought gas, what was the cost of that gas, and then he asks some other questions and put these several things together to create a picture of a revenue here that looks like about 3 million, a net margin or margin that would be related to the 16, or whatever you pointed out on that page.

Q. The difference between column G and column F is what you said would be $3 million?

A. That's right, roughly. I'm just telling you how I think he created the table. He's got a total revenue and he's got a gas cost.

Q. Okay. And what is reflected on Exhibit 1 would be for off-system sales, that 16.4 million would be a net, again, a net revenue number.

A. Yes, it would be.

Q. Okay. If you look at page ES-7 of the audit report, in the second column, second paragraph down, the auditor discusses 1,150 transactions, off-system sales transactions, that were reviewed, and there were 11 of those transactions that were sold at a loss, and Columbia explained to the auditor that there were $14,945 of avoided costs that essentially made those 11 transactions not at a loss; is that correct?

A. That's correct.

Q. And can you explain what avoided costs are?

A. Yes. Avoided costs is the terminology that we use according to the portion of the stipulation that talks about other avoided costs or savings and other avoided costs that result from transactions. And this is within the off-system sales definition.

Avoided costs in this context that we're talking about was described in some detail in one of the interrogatories, 117, I believe. I'll try to describe what that says.

In all of these cases, the avoided costs was created by avoiding transport costs that were already being incurred. Again, this comes down to volatility in the marketplace, and usually in these cases what we are talking about is locational values. Got gas, buying and purchasing at Point A, and if, in this particular case that's with all 11 of these things, I think, is that we were selling -- I'm going to get myself confused. I better slow down.

We buy gas at another point on an incremental basis. We sell gas at Point A so that in the end when you got the original purchase and you have a purchase and a sale, the net result of that is still one purchase, say, one decatherm still coming to our market. Nothing has chanced. We intended to buy X decatherms today, fill storage or whatever we were doing there, and that is still is the case after this is done because the volumes tie out, and you're left with two purchases and a sale, essentially, so you net one purchase.

The physical side, therefore, nothing has changed. The financial side is we pay less transportation and shrinkage because we are not moving the gas from Point A to Point B, as a simple example. In these examples, what you end up with, even though the gas that we -- let me see. This is really hard to do by waving your arms.

The net financial result is a lower cost.

When you net out, you include the fee that we're paid for the exchange, or even if we pay somebody -- not exchange, the fee that we're paid for this incremental sale, the fee that we're -- I wish I had 17 in front of me. It would be a little easier for me. You could show a loss here of a nickel. I have records and books that show savings of 6.6 cents, and the net of that was a positive 1.6 cents and that's what our records show.

The avoided costs, I mean, it's what it says. It's costs -- if we had done nothing we would have incurred some costs. Because of this transaction, this incremental off-system sales transaction, we applied to whatever we were doing that month, our total costs went down. And we record those costs and they are, you know, along with, once in a while, taxes or that kind of thing or transportation costs that we charge against ourselves in the off-system sales.

It's all in that same cost issue. It's not what we bought -- it's not what we paid for the gas. We bought the gas from producer X, and we paid them $6, but there's other elements of the off-system sale, one of which is avoided costs, if any. Another is if we transported the gas, we incur that cost. If we have to pay a tax for some reason in some state, we incur that cost.

Q. You said originally there was a purchase and a purchase and a sale.

A. Originally there was a purchase. That's part of our system supply that would have been bought for the month.

Q. Now, did that -- was the original purchase one transaction, the subsequent purchase and sale a second or a second and third transaction?

A. Yes, there's three transactions altogether.

Q. Three transactions that would have been part of that original 1,150 transaction that the auditor looked at.

A. No. In the original transaction in this case where we have gas flowing to Point A to Point B -- I don't remember exactly if this was the case on this one. But let's say it was one of those term purchases or 30-day spot purchase or something, picking it up here and we are taking it up here.

I'm trying to think of a good way to describe it.

MR. SERIO: Let's go off the record for a second.

(Discussion off record.)

A. Originally the original purchase I talked about is not one of the 1,150.

Q. Okay.

A. It's a purchase for system supply that was preexisting.

Q. So it's not an off-system or a capacity-release transaction?

A. That's correct. The off-system transaction is the incremental purchase and sale.

Q. Who would have the original transaction been with?

A. One of our suppliers.

Q. Why would that be outside of an off-system or capacity-release transaction?

A. We really didn't do anything with that transaction, per se. We didn't stop that gas. We still had the transaction with them, and they were --in terms of the incremental pieces of this, let me be more specific. In this one example, we bought gas incrementally for $6.34. Same day incremental we sold gas for $6.29. The reason one was more expensive than the other was because the more expensive one was closer to the marketplace, closer to us physically.

So that's your location value difference. We're taking a five cent hit for that. That's this number that he found in the audit that added up to whatever he said. But we didn't have to -- because of the location where we bought the gas and sold the gas, we dropped transportation and shrinking charges between Point A and Point B. On a net basis we had that many decatherms less of transportation and shrink between those two points. That value of that is 6.6 cents.

So in the first one on the list of these 11, the real margin that we recorded in our records was 1.6 cents. That's the avoided cost, is the 6.6 cents piece of that. The volatility between these locations, some days it's more than the transportation costs, some days it's less than the transportation costs, things like that.

Q. Had avoided costs been recorded in all off-system sales transactions?

A. I'm not sure what you're asking. If there were some we identified, we did record them.

Q. Okay. There may not be avoided costs in every off-system sales transaction.

A. Certainly not.

Q. But if there were, they were recorded and included in the revenue for off-system sales.

A. That's correct.

Q. I think in the last set of discovery we asked for that information, and I think Steve just sent that to us late yesterday, and I haven't had a chance to go through all that.

Did you participate in preparing a response to that?

A. Yes. Im trying to think what question that was.

Q. I don't remember the number either. This was some response to the amount of avoided costs that were actually incurred and recorded as revenue

A. It was like 114 to 118, and I did those.

Q. You indicated in the one transaction you looked at there was 6.6 cents in revenue, 5 cents in avoided costs and 1.6 cents net.

A. I believe you said that backward, but I'll say it. The 6 .6 is the avoided cost. The 5 cents is, say, the cost because you sold gas for less than you paid for it. That was the 5 cents.

Q. What gets recorded as off-system sales in the off-system sales revenue?

A. 1.6.

Q. 1.6. In the MP audit report at page 3-4, under the last paragraph in the right-hand column, it says: 94 percent of Columbia's pipeline points of delivery are daily measured. Do you see that?

A. Yes.

Q. And the remaining 6 percent are not metered.

A. Yes.

Q. Are there any steps being taken to expand the metering to include the other 6 percent?

A. I'm not sure, but Mr. Ripley might know the answer to that.

Q. Are you familiar with straddle transactions?

A. Somewhat.

Q. Can you describe your understanding of straddle transactions?

A. I look at that as a hedge position somebody is implementing to close in the ultimate costs of gas, similar but not quite the same as like a collar around some pricing.

Q. Does Columbia Gas of Ohio get involved with straddle transactions with affiliates --

A. No.

Q. -- Columbia distribution affiliates.

Does Columbia Gas of Ohio do straddle transactions at all?

A. No, we don't.

Q. Are there any transactions that might be similar to straddle transactions that would be referred to by Columbia Gas of Ohio under a different name?

A. Well, I did indicate our hedging plan discusses collars, and we have the ability to do collars in that plan, and, in fact, did, I think in the very first year or so. We haven't done any since, mainly because it seems -- there's kind of an asymmetric to the puts and calls, doesn't look as good of deal as just fixing the price to me. That's the nearest thing I think we got.

Q. And the first year of the hedging plan was 1998; is that what you said?

A. Yes.

MR. SAUER: We're finished.

MR. SEIPLE: We will review that for signature as well.

(Signature not waived.)

(Thereupon, the deposition concluded at 3:05 p.m.)

- - -

State of Ohio :
: SS:
County of ____________________ :

I, Scott Phelps, do hereby certify that I have read the foregoing transcript of my deposition given on Tuesday, October 16, 2006; that together with the correction page attached hereto noting changes in form or substance, if any, it is true and correct.

____
Scott Phelps

I do hereby certify that the foregoing transcript of the deposition of Scott Phelps was submitted to the witness for reading and signing; that after he had stated to the undersigned Notary Public that he had read and examined his deposition, he signed the same in my presence on the ________ day of ______________________, 2006.

____
Notary Public

My commission expires _________________, ________.

\- - -

CERTIFICATE

State of Ohio :
: SS:
County of Franklin :

I, Rosemary F. Anderson, Notary Public in and for the State of Ohio, duly commissioned and qualified, certify that the within named Scott Phelps was by me duly sworn to testify to the whole truth in the cause aforesaid; that the testimony was taken down by me in stenotypy in the presence of said witness, afterwards transcribed upon a computer; that the foregoing is a true and correct transcript of the testimony given by said witness taken at the time and place in the foregoing caption specified and completed without adjournment.

I certify that I am not a relative, employee, or attorney of any of the parties hereto, or of any attorney or counsel employed by the parties, or financially interested in the action.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal of office at Columbus, Ohio, on this 23rd day of October, 2006.

____

Rosemary F. Anderson,
Professional Reporter, and
Notary Public in and for the
State of Ohio.

My commission expires April 5, 2009.
(RFA-6916)

\- - -

State of Ohio :
: SS:
County of FRANKLIN :

I, Scott Phelps, do hereby certify that I have read the foregoing transcript of my deposition given on Tuesday, October 17, 2006; that together with the correction page attached hereto noting changes in form or substance, if any, it is true and correct.

Scott D. Phelps

Scott Phelps

I do hereby certify that the foregoing transcript of the deposition of Scott Phelps was submitted to the witness for reading and signing; that after he had stated to the undersigned Notary Public that he had read and examined his deposition, he signed the same in my presence on the 26TH day of OCTOBER, 2006.

Stephen B. Seiple

Notary Public

STEPHEN B. SEIPLE, Attorney-At-Law
NOTARY PUBLIC--STATE OF OHIO
My commission has no expiration date.
Section 147.03 R. C.

My commission expires ________, ________.

\- - -

Errata Sheet
For Deposition of Scott Phelps
Taken on Tuesday, October 17, 2006

Page 1, 3, 84, and in cover letter to Scott Phelps	Deposition taken on Tuesday October 17, not Tuesday October 16.	Mistaken date
Page No. & Line Reference	Correction	Reason for Change
Page 24, line 4	"of" should be "or"	Typing error
Page 38, line 5	"shorter" should be "shoulder"	Hearing error
Page 41, line 21	"aberration" should be "application"	Hearing error
Page 60, line 6	"do" should be "use"	Hearing error
Page 60, line 23	Insert "as" between "frame" and "the"	Lost word
Page 66, line 18	"as" should be "was"	Typing error
Page 75, line 11	"chanced" should be "changed"	Typing error

FILE

OCC Deposition
Exhibit No. 1

15

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Service.	)	Case No. 94-987-GA-AIR
In the Matter of the Application of Columbia Gas of Ohio, Inc. to Establish the Columbia Customer Choice[SM] Program.	)	Case No. 96-1113-GA-ATA
In the Matter of the Regulation of the Purchased Gas Adjustment Clause Contained Within the Rate Schedules of Columbia Gas of Ohio, Inc. and Related Matters.	)	Case No. 98-222-GA-GCR
Application of Columbia Gas of Ohio, Inc. to Revise its Tariffs to Establish a New Gas Transfer Service.	)	Case No. 03-1459-GA-ATA

REPLY COMMENTS
OF THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
REGARDING
COLUMBIA GAS OF OHIO'S
OCTOBER 9, 2003 STIPULATION AND RECOMMENDATION

Introduction

The Office of the Ohio Consumers' Counsel ("OCC") hereby submits these reply comments pursuant to the attorney examiner's entry of November 13, 2003. Herein, the OCC responds to the comments filed December 8, 2003 regarding Columbia Gas of Ohio, Inc.'s ("Columbia") Stipulation and Recommendation filed in the above-captioned dockets on October 9, 2003. The OCC's failure to respond herein to any comment does not necessarily mean that the OCC accepts the position taken. With respect to any of the issues raised by the stipulation, the OCC respectfully refers the Commission to the OCC's initial comments filed in these dockets on December 8, 2003, which comments are hereby incorporated by reference.

A. The Commission must reject the stipulation and exercise its statutory authority to determine the reasonableness of Columbia's pipeline capacity contracting decisions in gas cost recovery proceedings.

While Columbia stresses the reliability that it claims will result from the stipulation, the issue presented by the stipulation is whether Columbia's pipeline capacity contracting levels are far in excess of what is actually required to assure reliability. Pursuant to the stipulation, Columbia will renew its contracts with interstate pipelines, including its own NiSource affiliate pipelines, to provide Columbia the capacity to serve as much as 100% of its core market customers, including choice customers. The management/performance auditor in Columbia's current audit proceeding questions whether Columbia's capacity contracting decisions are reasonable, realistic and consistent with Columbia's experience under the choice program. *Columbia Gas of Ohio, Inc.*, Management and Performance Audit, Case No. 02-221-GA-GCR at 4-47-49.

Columbia also stresses the certainty that it claims will result from the stipulation, but the issue is whether Columbia's pipeline capacity contracting will continue to escape regulatory oversight. Columbia Comments at 6. To the extent that the certainty Columbia seeks results in a lack of regulatory oversight of its capacity contracting decisions, such certainty is not in the public interest.

The stipulation forecloses the Commission's authority to review Columbia's pipeline capacity contracting for the entire six-year term of the stipulation. As the OCC argued in its initial comments, the Commission should not forgo for the stipulation's entire six-year term its statutory authority to review Columbia's capacity contracting decisions in the context of the gas cost recovery ("GCR") audit proceedings. Columbia itself points to the problems that result when regulators are not given needed levels of oversight authority. Columbia Comments at 6-7. Given that the stipulation denies the Commission the level of oversight authority that the General Assembly saw fit to confer upon it, the Commission should reject the stipulation and maintain its oversight authority.

Columbia's reference to the "unstable and rapidly changing environment" of natural gas markets should also cast doubt on the wisdom of pre-approving Columbia's pipeline capacity contracting for the entire six-year term of the stipulation. Columbia Comments at 7. If gas markets continue to experience rapid change and increasing volatility throughout the entire six-year term of the stipulation, the Commission will not want to have pre-approved so far out into the future Columbia's pipeline capacity contracting decisions. If governmental aggregation pursuant to Sub. H. B. 9 results in choice participation rates as high as 82% by the end of calendar year 2007 as Columbia itself is projecting, again, the Commission will not want to have pre-approved Columbia's pipeline capacity contracting decisions for as far into the future as the stipulation provides. See OCC Attachment A at 3, Columbia's response to OCC Interrogatory No. 3.

The Commission Staff warns the Commission not to be locked into Columbia's proposal for such an extended period of time. Staff Comments at 2. Given the questionable and controversial nature of Columbia's proposal for re-contracting to serve 100% of its core market customers, the lack of Commission oversight is not reasonable. The length of the stipulation is too long a period of time to remove such an important issue as the level of capacity contracting from the Commission's purview. The Commission should reject the proposed stipulation in favor of a thorough regulatory review of this issue in GCR audit proceedings.

B. The stipulation harms ratepayers.

While Columbia itself makes little or no effort to support the various stipulated funding provisions, Interstate Gas Supply, Inc. ("IGS") and WPS Energy Services, Inc., dba FSG Energy Services ("WPS") fill the void by arguing in support of several of Columbia's stipulated funding provisions. IGS and WPS argue that the stipulation makes Columbia responsible and at risk for certain choice program costs. IGS and WPS Comments at 11.

Columbia's own analysis of the funding provisions shows that the actual risk to Columbia is negligible. Columbia projects the funding from the stipulation's various sources to exceed choice program costs by $68 million even before adding funding from post-in-service carrying charges ("PISCC") and other deferrals totaling an additional $124.2 million more. See OCC Attachment A at 2, Columbia's response to OCC Interrogatory No. 3. In other words, the funding from the stipulation's various sources is projected to exceed choice program costs by $68 million **and in addition to that excess $68 million, Columbia will accumulate PISCC and other deferrals totaling another $124.2 million** during the term of the stipulation. Therefore, rather than putting Columbia at risk for choice program costs, the stipulation is designed to over-fund such costs.

Moreover, with regard to the excess $68 million that the stipulation is designed to generate for Columbia, $46.4 million is provided by direct contributions from ratepayers in the form of the migration cost rider. Id. Even if there were no such direct contributions from ratepayers through the rider, the stipulation would still over-fund Columbia's projected choice costs by $21.6 million. Thus, even if the Commission were to reject the cost migration rider, the stipulation would still over-fund Columbia's projected choice program costs by $21.6 million plus the $124.2 million in PISCC and other deferrals. Therefore, given Columbia's own analysis, rather than putting Columbia at risk, the stipulation is designed to over-compensate Columbia for its projected choice program costs.

The over-funding of choice program costs is particularly improper when, as the Staff points out, Columbia's stipulated provision for re-contracting pipeline capacity actually creates stranded costs. Staff Comments at 2. With the October 2004 expiration of a significant amount of Columbia's capacity contracts, Columbia has the opportunity to shape its capacity portfolio to eliminate stranded costs. According to the Staff, the stipulation's provision for re-contracting for capacity to serve 100% (reduced to 95% after October 1, 2005) of its core market customers is unreasonable given the current levels of migration experienced by Columbia. Staff Comments at 2. The Staff believes that Columbia's decision to re-contract at the stipulated levels is the driving force behind the creation of the stipulation's funding sources. Re-contracting at a level that more realistically reflects the impact of the choice program would eliminate the need for these funding sources. Staff Comments at 3.

With regard to other purported benefits of the stipulation, the OCC does not agree with Columbia that customers will benefit from the stipulation's base rate freeze. Columbia Comments at 7. As the Staff points out, the PISCC and other deferrals render the base rate freeze provision worthless to customers. Staff Comments at 5. Even though Columbia would not file a base rate case until October 31, 2010, that rate case would include carrying charges on the plant investments (including the unamortized balance of accrued PISCC) and the unamortized balance of deferred depreciation and property tax expense from the stipulated period. Columbia would not forgo recovery of any of these costs, but merely recover them at a later time. PISCC compensates Columbia for the delay in cost recovery. In addition, the numerous exceptions to the rate freeze, especially the stipulation's failure to preclude automatic cost adjustments pursuant to R.C. 4929.11, also render the stipulated rate freeze of dubious value to ratepayers. Staff Comments at 6-7.

Columbia also claims incorrectly that the stipulation will result in reduced demand rates for GCR customers. The 2003 stipulation itself creates no such result. Rather, the reduced demand rates result from the termination of the 1999 Columbia stipulation. Once the 1999 stipulation terminates, Columbia will no longer be able to calculate the GCR based on the provisions of that stipulation. The termination of the 1999 stipulation is the sole factor that reduces demand rates for GCR customers.

Columbia also implies that the stipulation brings about enhanced capital program investment in line extensions, economic development, pipeline safety and infrastructure reliability. Columbia Comments at 6. The stipulation's impact on such matters is actually nothing more than its provisions for the deferral of PISCC and all depreciation and property tax expense on all property on which PISCC is calculated. Stipulation at 21. As the OCC stated in its initial comments, these deferrals will create, without any demonstration of any necessity for such deferrals, regulatory assets that Columbia will seek to recover from ratepayers at some future date. These deferrals will inflate Columbia's earnings during the years of the stipulation and increase the revenue requirement at the time of any subsequent base rate case. As the Staff of the Commission correctly points out in its comments, the PISCC provisions allow Columbia an opportunity to recover expenses in a future proceeding that, absent the approval of the stipulation, Columbia would not be able to recover. Staff Comments at 6.

Finally, Columbia also points to the continued customer benefits from the choice program. While consumers have experienced savings from participation in the program, the management/performance auditor in Columbia's current GCR audit proceeding casts doubt that customer benefits from the choice program have recently been as robust as Columbia is projecting such savings to be during the term of the stipulation. Columbia Comments at 7. Columbia has estimated that customer savings from choice may be as high as $50 million to $63 million per year during the six-year term of the stipulation. See OCC Attachment A at 2. Such estimates greatly inflate the more recent experience for customer savings under the choice program. The management/performance auditor provides total customer savings for each month from November 2000 through October 2002. Management/Performance Audit at 7-7. For an entire year from August 2001 through July 2002, the aggregate savings to customers in the choice program actually were negative. During the last year of the audit period, choice customers were disadvantaged by $64.3 million. Id. at 7-6. Therefore, Columbia's projections for customer benefits from the choice program do not reflect the recent experience of choice customers.

C. Commission approval of the stipulation is not a pre-condition necessary for the continuance of the choice program in Columbia's service areas.

The Commission should not accept the argument made by certain marketers that the choice program in Columbia's service area will suffer unless the Commission approves the stipulation. IGS and WPS state that the unknown future of Columbia's choice program is already impacting supplier business decisions and that there is reduced marketing activity in Columbia's choice program compared to the Dominion East Ohio market where ongoing competition is certain and the marketplace stable. IGS and WPS Comments at 2. IGS and WPS argue that approval of the stipulation is necessary to protect the Columbia market and that failure to approve the stipulation will result in a diminution of offers due to the uncertainty surrounding the post-November 1, 2004 period.

While the stipulation may act to give the marketers information about how the Columbia choice program will operate during the six-year term of the stipulation, the marketers cannot contend that there is no certainty in the absence of the stipulation. Columbia already has on file with the Commission the tariffs that prescribe the operation of the choice program in its service areas. Columbia also has pending an application to conform its tariffs to the requirements of Sub. H.B. 9 and the Commission's administrative rules adopted to implement the provisions of Sub. H.B. 9. There is no reason to believe that the Commission's rules and Columbia's tariffs are inadequate to provide marketers with the information they need to operate in Columbia's service areas. In addition, there is no comparable stipulation in the Dominion East Ohio service areas that would lend credence to the notion that a stipulation such as Columbia's is necessary for the success of the choice program.

Columbia cannot unilaterally terminate the choice program. Even if Columbia attempted to begin the process to end the choice program in its service areas, those seeking choice are not without remedy. Any effort on Columbia's part to withdraw its Sub. H.B. 9 tariffs would be met with certain opposition by various interested parties. Moreover, there are provisions in Sub. H.B. 9 that allow petitions to be filed with the Commission to require a natural gas company with fifteen thousand or more customers to provide distribution service. R.C. 4929.29. Therefore, it is not true that the choice program is dependent upon Commission approval of the stipulation.

Conclusion

The stipulation is a bad deal for residential ratepayers. It forecloses Commission review of Columbia's pipeline capacity contracting for the entire six-year term of the stipulation. It harms ratepayers by pre-approving funding sources and revenues for Columbia without the statutory procedures for the approval of such sources and revenues. It over-funds Columbia's own projections for costs due to customer migration. It allows for the creation of new regulatory assets that will cause Columbia's revenue requirement to increase at the time of Columbia's next base rate filing.

Thus, as the OCC stated in its initial comments, the Columbia stipulation fails the criteria set forth by the Commission and approved by the Supreme Court for the approval of settlements. The stipulation violates numerous important regulatory principles and practices; it harms ratepayers and is not in the public interest. Therefore, the Commission cannot approve the stipulation.

Respectfully submitted,

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Deputy Consumers' Counsel

Colleen Mooney

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Larry Sauer
Assistant Consumers' Counsel

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CERTIFICATE OF SERVICE

I certify that a copy of these *Reply Comments of the Ohio Consumers' Counsel* was served by first-class U.S. mail, postage prepaid, to the parties identified below, this 22nd day of December 2003.

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PUCO Case No. 94-987-GA-AIR, *et al.*
OCC Interrogatory No. 3
Respondent: Larry W. Martin

**COLUMBIA GAS OF OHIO, INC.
RESPONSE TO OCC INTERROGATORIES**

Interrogatory No. 3

Referring to the Stipulation at Paragraph 9, pages 11-12:

a. What are the annual estimated amounts for "Choice Program capacity costs" as defined in Paragraph 9?

b. In determining the costs in response to Subpart (a) of this interrogatory, what are the choice participation rates assumed?

c. What are all the other assumptions used in determining the costs in response to Subpart (a) of this interrogatory?

Response:

a. See Attachment 3(a), Line (2), CHOICE Program Costs.

b. See Attachment 3(a), Line (1), CHOICE Participation.

c. See Attachment 3(b).

__Assumptions:__
Capacity reduction of 5% starting '06
PISCC beginning 11/1/04
Surcharge escalates as participation increases
Sharing of OSS/Cap Rel. over $35 M

30-Sep-03

Line No.		2005	2006	2007	2008	2009	2010	Total
1	CHOICE Participation	62%	67%	82%	82%	82%	82%	
		$M	$M	$M	$M	$M	$M	$M
2	CHOICE Program Costs	125.5	135.6	165.7	165.7	165.7	165.7	923.0.
3	Marketer Revenues							
4	Balancing Services	39.9	43.1	55.1	55.1	55.1	55.1	
5	Capacity Assignment	41.2	44.5	52.6	52.6	52.6	52.6	
6	Increase to 75%	13.0	14.2	16.6	16.6	16.6	16.6	
7	Total Marketer Revenues	94.1	101.8	124.3	124.3	124.3	124.3	693.1
8	Net CHOICE Program Costs	31.4	33.8	41.4	41.4	41.4	41.4	230.8
9	Less: 5% Capacity Reduction	-	10.0	10.0	10.0	10.0	10.0	50.0
10	Final Net CHOICE Program Costs	31.4	23.8	31.4	31.4	31.4	31.4	180.8
11	Sharing Mechanism on OSS/Capacity Rel.							
12	Capacity Release	14.8	16.0	18.8	18.8	18.8	18.8	106.0
13	Off-System Sales	16.4	16.0	16.0	16.0	16.0	16.0	96.4
14	Total OSS / Capacity Release	31.2	32.0	34.8	34.8	34.8	34.8	202.4
15	OSS/Cap Release Shared over $35 M	-	-	-	-	-	-	-
16	50% COH if CHOICE Part. < 60%							
17	60% COH if Part. 60% - 69%	-	-					
18	70% COH if Part. 70% - 79%							
19	80% COH if Part. >= 80%			-	-	-	-	-
20	Funding Sources							
21	Capacity Release + OSS after sharing	31.2	32.0	34.8	34.8	34.8	34.8	202.4
22	Surcharge Revenue = $0.03, $0.035, $0.05	5.3	6.1	8.8	8.8	8.8	8.8	46.4
23	Total Funding Sources	36.5	38.1	43.6	43.6	43.6	43.6	248.8
24	Net CHOICE Program	5.1	14.3	12.2	12.2	12.2	12.2	68.0
25	PISCC	2.9	9.8	17.0	24.2	31.6	38.7	124.2
26	**Total Funding**	8.0	24.1	29.2	36.4	43.8	50.9	192.2
27	Customer Benefits	2005	2006	2007	2008	2009	2010	Total
28	Net CHOICE SAVINGS	50	53	63	63	63	63	353.0
29	Net GCR Savings	11	10	5	5	5	5	39.7
30	Base Rate Freeze	17	17	17	17	17	17	102.0
31	Total Customer Benefits	78	80	84	84	84	84	494.0
32	Net Benefit	69.9	55.4	54.9	47.7	40.3	33.2	301.2

Attachment 3 (b)

Major Assumptions Used In Development Of Columbia's Response to OCC Interrogatory No. 3(a)

- The implementation of the opt-out provision of HB 9 by various governmental entities will result in a significant increase in Columbia's CHOICE Program participation rates.
- The implementation of the HB 9 opt-out provision by these entities will result in a CHOICE Program participation rate of 62% by October 31, 2005.
- CHOICE Program participation rates will increase an additional 5% during the calendar year 2006 as more municipalities elect to participate in the program.
- There will be a major increase in Columbia's CHOICE program participation rates during Calendar Year 2007 as the program grows in popularity. This will result a decision by major municipalities to become Natural Gas Aggregators and will result in an overall participation rate of 82% by the end of the calendar year 2007 which will remain constant for the balance of the term of the Stipulation.
- COH contracts for peak day capacity equal to 100% of the demand of core market and GTS standby customers for the first year, 2004-05.
- This peak day capacity contract level will be reduced to 95% of the demand of core market and GTS standby customers during the 2005-2006 gas year and remain constant for the balance of the term of the Stipulation.
- COH contracts for peak day capacity based on a design temperature with a 10% risk level.
- COH serves as the Provider of Last Resort.
- Total capacity costs are calculated based on projected contracted capacity and March 2003 pipeline rates.
- COH contracts for 70 MDth of Tennessee FT capacity and 433 MDth of Gulf FTS-1 capacity.
- COH contracts for either ANR or Panhandle capacity sufficient to meet operational needs on the west side of Toledo.