INDEPENDENT PRICING AND REGULATORY TRIBUNAL

ELECTRICITY RETAIL REVIEW WORKSHOP

Tribunal Members

Dr Michael Keating AC - Chairman
Mr James Cox
Ms Sibylle Krieger

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Cnr Phillip and Bridge Streets, Sydney

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KEATING: Good morning to everybody, thank you for your presence. My name is Michael Keating and I am Chairman of IPART. On my left is Jim Cox, who is the Chief Executive Officer of IPART and a full time member, and on my right is Ms Sibylle Krieger, who is the Tribunal's part time member.

As you would all be aware today, the Tribunal has engaged Frontier Economics to provide advice on energy costs and mass market new entrant operating costs and mass market new entrant retail margins. Frontier's work on energy costs covers a number of elements, including the long run marginal cost of a portfolio of new entrant generation to supply a regulated load, the cost of purchasing electricity in the market, including hedging, risk management and transaction costs, the costs of compliance with green energy requirements, including Commonwealth mandatory renewable energy targets in the New South Wales greenhouse gas abatement scheme and national energy market fees and ancillary charges.

Frontier provided draft reports to the Tribunal in December and those reports have been made available by the Tribunal on its website. Submissions on those draft reports from the major stakeholders are due on Friday, 2 February, that's next Friday, tomorrow week. It is important if we're to keep to our timetable, and there is a very firm deadline at the end of this whole process, so it is important that we get the submissions on time.

The purpose of today is to allow interested parties the opportunity to provide feedback to both Frontier and the Tribunal on Frontier's draft reports. After considering your comments and submissions, Frontier will provide final recommendations to the Tribunal, which will be used then in the Tribunal's draft determination which is due for release in April.

We have divided today's program into four sessions, so there's a session on each of, firstly, the long run marginal cost of purchase electricity, secondly, market based electricity purchase costs, third, mass market new entrant retail costs, and then the fourth session will be on mass market new entrant retail margins, and that follows basically the way the reports themselves have been presented by Frontier. In each session Frontier will give a short summary of its draft findings and recommendations, that's how we'll start each session, and I'll then invite key stakeholders to provide a further comment on Frontier's draft recommendation. I'd like to ask you to keep these brief and to the point. I'm sure every Chairman says that, but you can see for yourselves that to fit in adequate time for each speaker on each topic and still finish when we propose to, they will need to be brief and to the point.

Following those presentations, I'll invite questions and comments from anybody else in the room. We propose to have a short lunch break after the second session, so that's midway through the proceedings, and finally can I ask you to note that this hearing is being transcribed and so you will need to identify yourself and your organisation before speaking and it will help the transcribers if you speak loudly and clearly.

I would now like to call on Frontier, Danny, to take us into the first topic.

PRICE: Welcome everyone today. My name is Danny Price, I'm Managing Director of Frontier Economics. This first session is about the analysis and results of the long and marginal cost of generation. I'm sure you've all seen the terms of refernce, but just to refresh people's memory, the terms of reference, I think it was in fact the first one, said that an energy cost allowance needs to be assessed or estimated based on the assessment of long or marginal costs of electricity generation. It went a bit further and gave us a bit more guidance as to how that's to be done by saying it should be the formulation of an optimal portfolio of new generation to meet a particular load, so it was guiding us towards a sort of stand alone type assessment of the costs of meeting the regulated load.

Further on the energy costs, the terms of reference talked about the need to include an allowance for the retailers' greenhouse obligations, and that obviously in New South Wales includes the obligations for the Commonwealth scheme and the New South Wales Greenhouse Scheme, the GGAS Scheme. You'll also note that in the course of doing this study, the government also announced that it had intended to develop a state-based renewable scheme commonly known as NRET. Whilst the details of that scheme are yet to be developed, we've estimated a preliminary cost on the basis of what we know about the scheme, so we included that as well in the report, but as I say, that could change as the policy develops, but so there's really two broad approaches for estimating long run marginal costs. In practice there's thousands of potential approaches, but two broad approaches, as I've indicated, there's what we've called here a stand alone approach, and that really looks at the costs of meeting a particular load as if no other load existed and then there's an approach which is commonly used, which is a sort of incremental load approach and that looks at the incremental costs of making an incremental load off an existing system. It's generally the case that the second approach results in a lower cost, because it gets the benefit of plant that already exists in the system, any spare capacity, but it can also incur the costs of some of the inefficiencies of an existing plant mix as well. But by and large the stand alone approach tends to yield a higher cost. That's neither here nor there, it's just a fact.

So the issue is which one is more consistent with the terms of reference. If you look back at the terms of reference, it talked about the costs of meeting a particular load, the load profile of a particular load and a generation portfolio that would be associated with supplying that particular load. So that tended to cause us to think the stand alone approach was more consistent with the requirements of the terms of reference and in that vein we've provided the estimates of the stand alone long run marginal costs.

There's at least as many models as there are opinions about how to calculate long run marginal costs. We've got our own, otherwise known as Whirlygig. Whirlygig is the sort of standard model that you see in the market, it's a mixed integer programming model, it's a mathematical optimisation model seeking to minimise the costs, so our optimal objective function is really cost minimisation, it has no notion of profit as such, it's trying to minimise total fixed and variable costs of generating electricity to meet the regulated load. The model is capable of inter-temporal, inter-regional modelling, we've applied that to the national electricity market and at the same time we've also used the exact same model to optimise the costs of meeting the MRET and GGAS and NRET Scheme. So the same model, the same data forms the basis of those estimates.

For every model you need data. The plant costs assumptions are obviously a key input into Whirlygig. I should tell you at this stage that we've based this data on the NEMMCO ACIL Tasman data, it's a publicly available source so you can replicate the study. There has been the inclusion, inadvertent inclusion of some cheaper plant options in that report and the model has picked that up, so we need to revise that. That will lead to a somewhat higher price. So the estimates that have been available in the draft report are slight underestimates, but a fresh set of estimates will be in the final report. Obviously that database includes quite a lot of plant cost options. The main ones for New South Wales of course are coal, open cycle gas turbine, closed cycle gas turbine. The greenhouse options include a wide range of options which are well known to all of you and the costs are also well known to all of you.

Just to refresh your memory, and remembering that these are somewhat underestimated, there are differences, I think most notably between Energy Australia and Integral Energy as compared to Country Energy. Those differences are mostly associated with the characteristics of the load, ie, Country Energy's load is a lot flatter, more stable than Energy Australia and Integral's, and Integral and Energy Australia are very similar, which initially surprised us.

Those cost estimates represent a demand weighted average costs, long run marginal optimal costs for non renewable generation, so this is what we call [black?] generation, and in estimating that we've obviously had to, because we're not building off the system, so we have to construct a reserve requirement for really a system that doesn't exist. To estimate that reserve requirement we've used the NEMMCO standard of .002 per cent unserved energy, translated that into a megawatt requirement. It roughly translates into about a 15 per cent reserve plant margin. Included in that is the actual fixed and variable costs of meeting the energy requirement and the reserve requirement and those costs are simply divided through by the energy consumed by each of those retailers.

As I mentioned, we also use the same modelling approach or the same model to calculate the long run marginal costs of green. This is a bit more difficult, given the basis of the terms of reference and I'll focus first on the GGAS. For those who are familiar with this type of work, if I build a new system with new generation technology, then that new generation technology will as a by-product meet the New South Wales GGAS Scheme target. The effect of that is the incremental costs of meeting the GGAS target from an optimally constructed stand alone system is zero. That's an interesting academic point, but not very useful for the purposes of setting prices in the market.

When you see that GGAS number and for that matter also MRET and the NRET, those estimates are not on the basis of a stand alone system, that's a departure from the terms of reference simply because some of those numbers would be zero and that makes no sense to us. So we did those long run marginal cost estimates on an incremental approach, which is the second approach that we applied, and that's incremental to the system, so that was a lot more realistic in terms of the costs that would be incurred by a new entrant retailer.

An important point here is that the model actually has and the approach has no regard to costs which may have been incurred in the past. So a retailer may have incurred costs to meet these obligations some time in the past and those costs might actually be higher than the future costs. So that's something to consider and the reason for that is that the terms of reference talks about the costs for a new entrant, so obviously a new entrant doesn't face sunk costs from decisions made in the past.

Also in the report you'll note that we decomposed the costs. There's various ways of doing that as well. Obviously if you allocate costs to a particular customer, there's always the variable costs or the avoidable costs that are allocated to them and then you're left with the issue of how to allocate fixed costs, which fill many, many economic journals. In this particular way it's a standard approach where capacity costs for energy production has been allocated to energy consumers. You're then left with the capacity that's required to be put in place to meet a reserve requirement for those consumers. The way that we've allocated that is a bit cryptic, it talks about the allocation on the basis of scarcity of capacity. The way that works is at every point in time in the system there's a probability of loss of load. At peak demand times the probability of loss of load is a lot higher, which means that you allocate more of that reserve to those peak times than you would say at base load periods, so that was the basis on allocating the costs of reserve. That's a very quick thumbnail sketch of what we've done in respect of long run marginal costs.

KEATING: I think Integral Energy should be the first to respond.

WALDMAN: Good morning everyone. My name is Karen Waldman. I'm the General Manager of Regulatory and Corporate Affairs for Integral Energy. I'd like to thank the Tribunal for the opportunity to comment on the Frontier draft reports. I'm delighted to kick off the comments on behalf of the stakeholders and I'd like to start by I guess setting what we see as the scene for both aspects of the Frontier energy costs report, so both the long run marginal cost and then the energy purchase costs. This is a pretty significant and critical impact for IPART in its decision making processes. There are critical decisions to be made in relation to the energy purchase cost allowances that come out of this determination process and we believe that the difficult decisions about complex issues by IPART will affect the viability of the retail businesses going forward, the level of competition in New South Wales in the future, and the extent of the level of new generation entrants in New South Wales.

Therefore there are significant implications for IPART and the businesses in getting this energy cost allowance right and therefore IPART's framework needs to compensate for the risks associated with getting it wrong. In the advent, competition will ensure that prices above cost reflective levels will not be sustained. Specifically in relation to the long run marginal cost and granted this is in the terms of reference, it is a useful starting point, but hedging costs must be considered. In fact it's the contract market and not the long run marginal cost that's the relevant market for determining the energy purchase cost allowance. Yet we are drawn to consider in some way the long run marginal cost and note that it is sensitive to the input cost assumptions.

Danny has referred to some of the assumptions that Frontier have made and noted that the ACIL Tasman assumptions were estimated for NEMMCO and were used by Frontier and modified in some cases. In its original submission, Integral has been very transparent in its assumptions, for example in relation to fuel costs and capacity factor used. Integral has sought advice directly from ACIL Tasman to test the reasonableness of Frontier's assumptions and what we note is that, as Danny says, there have been significant changes since the initial study that Frontier used. Our indications are that there would be an increase, as Danny said, in Frontier's estimates of the long run marginal cost as a result of this and our submission will further expand on this issue. Thank you.

KEATING: Thanks Karen. Country Energy?

DE LORENZO: Thanks very much. I'm Justin De Lorenzo, the Group General Manager Finance and Business Development at Country Energy. Part of my responsibilities is the wholesale trading function. I'd like to first thank the Tribunal for giving us the opportunity to speak today and I'll move through a very quick presentation of our thoughts on long run marginal costs. The presentation is broken into two parts, first on energy and then on green costs.

Firstly, I just want to endorse the comments made by Integral Energy, but starting with some background, the terms of reference there, the Tribunal must consider the government's policy aim of reducing reliance on regulated prices importantly and also the effect of the determination on competition, which is a key aim.

In our view, and it's fairly obvious from the report that the long run marginal cost is well below the market rate forecast, and in our view therefore will not reduce reliance on regulated tariffs or promote competition, which are the key aims of the terms of reference. So we just think LRMC is a benchmark that's been used historically in the absence of market and competition, so therefore we think it provides a useful reference point when determining or trying to estimate long term efficient generation costs, but is not the most appropriate measure for forecasting of energy purchase prices where an active and competitive market exists, and we believe that exists today in the NEM. So on the energy side we believe it is inappropriate.

On the green side, turning to green, we believe underlying LRMC, which is discussed in the Frontier report, is the most appropriate methodology for greenhouse gas schemes in the absence of an active and competitive market. In our view again there isn't such a market for green instruments and many, many transactions historically and current are based on long term PPAs which reflect more closely generation cost and which link more closely to the aims of LRMC.

In terms of the outcomes in the report, the underlying LRMC appears to be adequate for MRET and NRET. However, for the GGAS it appears to understate the current and past cost of compliance and of course Country Energy will provide further information by the due date to the Tribunal to support that claim, we have already provided such information. Thank you, that's the end of my presentation.

KEATING: Thank you very much. Energy Australia?

MOODY: Thank you. Thanks for the opportunity to talk to you this morning. Phil Moody is my name from Energy Australia. I am our Executive Manager of Retail Pricing. Our presentation generally today will focus more broadly and specifically on the hedge costs and margin allowance, but we will use this opportunity to talk a bit about LRMC as well.

Just reiterating our overall feelings about this process, Energy Australia generally support a move towards less regulation than more and in the interests of a competitive market and encouraging investment in generation. We also believe that this can be facilitated through a focus on the R and also pass through components for the tariffs and hopefully minimising regulatory involvement once the determination is set. We'd also like to adopt a situation similar to that used in the network determinations where unforseen or unknown costs are in fact passed through and considered at the time they become known, and I raise that point specifically in relation to NRET. We don't really know enough about it at this point in time and we would consider that an excellent example of something that should be considered as a re-opener in any determination.

To talk about LRMC specifically, it's probably worthwhile saying that we generally support Frontier's modelling technique of the LRMC. LRMC is probably not our preferred approach in terms of how we would assess the energy costs allowance for the retail businesses. As consistent with Country and Integral, LRMC is not a number that we're exposed to in the market. The only thing that we are exposed to is spot and hedge prices, so they're the only things that really matter to us. In our opinion LRMC is perhaps a useful guide to help triangulate an appropriate energy cost with some other inputs, but we wouldn't rely on it in terms of the energy component for anything more than that.

In particular it does seem to be quite sensitive to a number of key inputs and one of them is [WACC?], which we'll explore these in more detail in our formal submission. Another issue in relation to the current numbers is that the relativity in the energy costs that have resulted between Integral, Country and EA, we don't believe are reflective of what we would expect to see, and I don't doubt that's what's come out of Whirlygig, but we suspect that there may be an issue with the input data in that case and we think that that's definitely well worth exploring.

This is a significant issue, we believe, in this current determination, that the current situation with I guess the relativities between Integral, EA and Country tariffs be resolved and certainly the information being presented at the moment would not resolve that and indeed it would even suggest that such an issue doesn't exist. We don't believe that's the case. Incidentally, that particular issue also affects the hedge cost analysis as well.

Unfortunately we haven't received the details of the input data that Frontier used, although we are aware, as Danny mentioned, that they've used the ACIL Tasman reports. However, there is a certain amount of, I guess for want of a better word, manipulation that has to occur to that data to fit it into certainly our LRMC model. So when we get that, and I understand it is coming, we'll obviously have more intricate things to say about that.

Also in the green space, we would again probably concur with Country and Integral in the fact that LRMC is probably more reflective of the way that the market's evolved and the way that the market has evolved and the way that we have purchased in the green market, and at the end of the day, these modelling exercises I presume are intended to reflect what's happening in the real world. So to put some context around that, these generators have tended not to exist, so they've actually required underwriting and long term PPA. So it's quite different to the way in which hedging and contracting has occurred in the energy market till now.

Another aspect of LRMC that is of some concern to us is even to the extent it is correct, it may or may not have any direct relevance to the three year window that we're looking at here. So it may be an appropriate measure over 20 or 30 or 40 or 50 years, but the businesses and industry here need to be able to cope with where we'll be exposed in the market over the next three years. So again in that regard LRMC is not appropriate.

I probably should say a few words about what it is that we do in these businesses, because I think it is an area that is probably a bit unfamiliar to a lot of people. A common retailer that people would be familiar with, such as Woolies or Coles or your local supermarket, takes very little risk in the area of the product they're selling, so they'll buy something and they'll sell it and hopefully make a margin along the way. The issue that we have as electricity retailers is that we can't actually buy, generally speaking, the product that we're selling to our customers. In fairness we could under the current determination, we had access to a product called the ETEF, which is a fairly rare and unique and I suspect disappearing opportunity and hence the margin that was allowed under the current determination reflects the fact of a more commonly understood retailer where you can buy what it is you're selling.

The issue for us is that there is significant risk around the purchase cost of the product we're selling, however there is very little risk around the revenue we're receiving for it and the fact that that purchase cost makes up a very significant component, in the order of 80 per cent of our cost base, and that the risk around that purchase cost can vary quite substantially, $5 to $10 a megawatt hour depending on what we're looking at. I just wanted to make those points. That just about wraps it up for us on LRMC.

KEATING: PIAC?

WELLSMORE: Thanks Michael. Jim Wellsmore from the Public Interest Advocacy Centre. We don't have a lot of comments to make. A lot of the more detailed technical work involved in this sort of exercise unfortunately is just beyond the scope that PIAC can bring. I'll just make some brief comments.

First of all, from our perspective I think we're most interested from a policy point of view in the stand alone aspect of the picture. So we're actually happy in broad terms with the approach that Frontier has taken. What's really interesting for us is that the sorts of numbers that's coming out of Frontier's work seeks to us to be fairly consistent with similar early exercises using different methodology that NERA has done I think at least twice in the past for the Tribunal. I'm not sure whether that's good for Frontier or that's good for NERA. From our perspective though we're obviously pleased - you wouldn't be surprised to hear that energy costs and long run marginal costs of generation still appears to be, if it's growing, growing at a fairly modest rate and we're well aware that there's a lot of debate in the market about what the right price of generation should be in the coming years and there's probably a consensus out there that it needs to be significantly higher than it is now, and I guess I would concede that PIAC's probably been a part of that consensus.

We're well aware that there is a lot of pressures, apart from just the viability of the retail businesses coming to bear in the wholesale market and in generation. On the other hand, we'd also make the point that that consensus has rarely been really tested by independent work. The reliability panel at the AEMC is currently doing its own work in that area and that work I think will be published hopefully in about a month's time so there'll be some basis for comparison. But I suppose the point I just want to make is that everybody basically agrees that generation costs are going up, but you know, what's interesting is to actually be able to sit back and say, well, here's someone who's done some work and trying to get a bit of a handle on just how much and how fast. The fact that we may not agree with Frontier, I guess I'm saying doesn't mean that they're wrong, albeit I take on board some of the points that have already been raised about some of the final detail of the approach that Frontier's taken.

From our perspective, we don't mind if people want to try to get a handle on costs by looking at contract costs, that's fine. Clearly the businesses need to be in the position to put their contracts on the table at least with IPART and disclose what it is that they are actually contracting for and at what price. But equally from our perspective, we'd be keen to understand the impact in the contract market of combined retail generation businesses and whether that in fact has a particular impact or an effect that sort of skews the contract market in a particular way.

Just finally, risk is something that doesn't disappear, you can't make it go away. You can pass it on to someone and essentially that's what higher prices for consumers will do. It won't take away risk, it just pushes the risk over onto us. Obviously once upon a time ETEF was doing the job of managing that risk, but for particular policy reasons the government has decided to do away with ETEF. As I say, we're not of a view, we wouldn't say that prices can't go up or shouldn't go up, but we're not from our very lay person type view, not being in the middle of the industry, we're not necessarily too perturbed with the sorts of numbers that Frontier has come up with. Thanks.

KEATING: AGL?

FOWLER: Thank you Mr Chairman. My name is Anthony Fowler, I'm the head of Energy Trading at AGL and we really appreciate the opportunity to comment on the work done by Frontier. I suppose for me as an energy trading manager, long run marginal cost is a very theoretical exercise. Today every customer that our business wins in the state of New South Wales results in me having to go to the marketplace and securing a hedge to back that contract. As of today right now if I were to go and purchase a hedging contract for New South Wales for a flat contract, it is trading at $41.70 a megawatt hour for the most absolutely dead flat contract, and we would expect that a typical mass market net system load profile could trade in excess of 50 per cent beyond that $41.70 when you take into account all the incremental costs of caps and intermediate products, if you like, to cover that particular load.

So for me it's a very theoretical exercise, it has no relevance at this point in the marketplace, nor does it have any relevance at any point over the foreseeable years of the wholesale market, [which is in the order of about $3 to $4 a megawatt hour?]. Quite directly for myself, when I have to write products to support our retail activities in New South Wales, I could not underwrite our retail business at this level, it's quite simple. If $38 or whatever it was for Country Energy was the allowed price, I could not underwrite that, it would not be a possible outcome for us.

Other comments in relation to the long run marginal cost methodology, I suppose much like Energy Australia we were surprised by the relativities of the different outcomes. It's not to say that it's right or wrong, it just doesn't seem to reflect what our expertise would have achieved for very, very different load shapes. We do consider that the long run marginal cost approach is more applicable to for example the renewables, environment. It's easy to focus on some very, very low prices that we see trading through the screens, particularly for the REC style products, however these are at small volumes and they reflect what we would consider to be an anomaly in the market place.

Certainly for AGL as a leading developer of renewable projects, we just could not build renewable projects at the levels that we see in the short term anomaly. So certainly the long run marginal costs approach is something more along the lines that we would require to get a new development project up and running and we would expect that of all of the other leading developers of renewable projects. Thank you.

KEATING: It is now open to comments and questions from anyone in the room.

HAMILTON: Graeme Hamilton from TRUenergy. First of all, thank you for the opportunity to ..(not transcribable).. We're coming from a slightly different perspective, we've historically supported the long run marginal cost ..(not transcribable)... Certainly the green prices, our position is similar to the other retailers ..(not transcribable)...

COLEBOURN: My name is Phil Colebourn, I'm from Delta Electricity. Actually we - I pretty much [have the mark?] for LRMC versus hedging costs ..(not transcribable).. In both cases in the low 50s ..(not transcribable).. The problem with the LRMC, I think, and I don't think it's a problem with methodology, but the underlying cost assumptions ..(not transcribable).. ACIL Tasman are way too low ..(not transcribable).. If you have a look at their 2003 report, they in fact have much higher costs, which were probably a bit more consistent with what many people would regard as the costs of new entry generation now.

So I guess my question, is there any intention ..(not transcribable).. to cast the net a bit broader on view of new entry costs or ..(not transcribable)...

PRICE: I think it's on a similar vein to Karen. I'd be interested to see ..(not transcribable).. but I have to say that I generally agree with ..(not transcribable)...

COLEBOURN: I'll just make the observation then that ..(not transcribable).. ACIL Tasman's view on ..(not transcribable)..generation in New South Wales in 2003/2004 ..(not transcribable).. and as other people commented, if that were the case, then people should be queuing at the door ..(not transcribable).. and that's not the case ..(not transcribable)..

KEATING: Other questions, comments? Well, I might just say a few words in relation to what we've heard. First of all, we understand that Frontier will be reviewing their ACILTasman database and that will lead to some upward adjustment, but as I understand it, it will still be coming out as significantly less than the present market prices when that's done.

There was a suggestion from Energy Australia that it might affect the relativities. It's not obvious to me at least why that would be the case, because the relativities, as I understand it, reflect the load profiles and--

UNIDENTIFIED MALE: ..(not transcribable)..

KEATING: Okay. Yes, well, perhaps you could pursue that, because on the load profiles that are in Frontier's report - I'm a total layman in this, but what stood out was that Country Energy's load profile is very different, but the difference between Integral Energy and Energy Australia's load profile wasn't that big to a layman, perhaps less than some people had previously assumed, on most data.

PRICE: That's certainly what that particular data says; it shown ..(not transcribable).. There are also some basic tests that you could do as a ..(not transcribable).. test, which is the regulated load should look like a ..(not transcribable).. And indeed it's probably worth mentioning that regulated load ..(not transcribable)..

KEATING: Yes, well, I hope that will be an issue. Another thing I just wanted to pick up on was the comments that were made about use of pass-through mechanisms. I think the suggestion was made that NRET for example was too uncertain at this stage to be incorporated; it should be handled by way pass-through, or I just find it interesting we've heard that and we'll think about that, because I think we'd accept that where something is very uncertain, this is an example of where you would use a pass-through mechanism, but you might put in something in the meantime that you thought, rather than putting nothing up front.

I guess the critical question, at least from what I heard, was how much notice we should take of long run marginal cost. Of course it's in our terms of reference, so we're not going to totally ignore it, but the suggestion that was put to us - I think I'm quoting Karen correctly - said it's not appropriate in an active and competitive market. No, it wasn't you, anyway, someone said it wasn't appropriate and there was general agreement around that proposition.

That of course puts a heavy weight on just how active and competitive the market is and I want to emphasis that, because that will be a critical issue for the Tribunal and I just want - while that hasn't come up directly in the way we've structured today, I want to take this opportunity of emphasising that in responding to the Frontier report, I think it would be useful in your responses if you could elaborate on this point about how active and competitive the market is.

I do note that the points being made in previous discussions, hearings and in your submissions, that if the price is too low, that inhibits competition. On the other hand, we want to regulate the price if there isn't competition. So it's almost a chicken and egg situation. But I think it's important that you do again address as much as you can this point about just how active and competitive it is. I guess to the extent that it's not active and competitive because of price regulation, anything you could say on how more active and competitive it would be if there were less regulation and move to deregulation, that would be helpful.

I don't want to say more on this point. Did you want to add anything?

COX: If I can just perhaps take up the last point just briefly, I think in thinking about the extent of competition in the market, it seems to me it's important not just to look at the market as a whole, but to consider segments of it, such as particular customer groups and to the extent that that can be done, I think that will be very helpful in thinking it through. I just make that point, if I could.

KEATING: Well, we might move then to the next topic, which is market based energy purchase costs, which we've already heard that's what we should be focussing on.

STEINKE: Thanks Michael. My name is Tony Steinke, I work for Frontier Economics. I guess we've talked about the long run marginal costs, but the terms of reference also mentioned that the determination was to take into account some other factors as well and that's the cost of purchasing energy from the market. This determination differs from previous determinations in a fairly fundamental way and that is that previous determinations have been made under the presence of either ETEF or vesting contracts which give the retailers some protection against risk of price movements. Under this determination ETEF will actually roll off and cease, leaving the retailers fully exposed to the market risks.

The terms of reference mentioned that the determination should recognise that ETEF will cease operation and to recognise the hedging, risk management and transaction costs that would be faced by retailers in the absence of ETEF, as well as forecasting risks. So basically ETEF managed volume risks, forecasting risks, as well as price risks for the regulated customer load previously.

The approach we took for the market based energy costs was to consider a trade off between energy purchase costs as well as the risks. There are many different ways you could hedge the regulated customer load shape and some of those might be relatively low cost ways of hedging, but relatively high risk, and there's a trade off to be made and each retailer may make a different trade off in terms of their optimal level of risk and cost in terms of trading those off.

The framework we've used in assessing the market based costs is based on portfolio optimisation theory, which has been around for a long time, just probably not applied to electricity as much as other markets like stockmarkets, et cetera. The approach basically determines what we call an efficient frontier, which describes the portfolio of assets, and when I say portfolio of assets, I mean basically different contract mixes to hedge the risks of the load. That provides the lowest risk for a given level of cost and there's many different potential contract mixes that will hedge the same load. They could all be efficient in terms of portfolio theory, they just correspond to different trade offs between risk and reward.

We have a model that does this for us, it's called Strike and it determines an efficient frontier for energy purchasing. The efficient frontier basically is a point where you can not achieve a lower cost risk hedge mix without increasing your level of risk and conversely you can't get a lower risk hedge mix without increasing your costs. The frontier for each business is dependant on the characteristics of the customer load, including the forecasts of the customer load and volatility of the load, the characteristics of spot prices and forecasts of the spot prices over the review period, so both the level of spot prices and the volatility. Importantly as well though it's dependant on the correlations between those two things. So for example if your retail load tends to spike up high at the same time that the pool prices do, you'll have a more costly load.

Some of the inputs into the model obviously were forecasts of prices and we used four sets of forecast prices. A set of forecasts was provided by each standard retailer and we also did our own internal forecasts and the prices we forecast were spot prices, including the level and volatility over time, as well as forward contract prices. For each retailer and for each year of the determination, each of the four sets of forecast prices we used to estimate an efficient frontier. So for example we applied Energy Australia's price forecasts to the load shapes of each of the three businesses and so on, as well as our own forecasts. So we have a range of efficient frontiers for each business' regulated load shape.

This is an example for Country Energy. The chart on the horizontal access shows the level of risk associated with a given hedging strategy, the vertical axis shows the average cost in dollars per megawatt hour of that strategy and there are four efficient frontiers on that chart reflecting the efficient trade offs you can make between risk and cost of serving that load. Naturally you're kind of drawn to two points on those curves. There's what we call the most conservative point, which is the top or highest part of each curve, and that is the point that delivers the lowest risk portfolio. There's a point just below that which we've termed the elbow point and we've put a little circle around that, and that basically just reflects the point where you've - compared to the conservative point, you've achieved a lower cost portfolio for a relatively small increment in risk. And then there are many other points on the frontier too reflecting much higher levels of risk for very small gains in terms of costs. So for each business we have four efficient frontiers.

The results of the analysis, and we've summarised this in a range, so this is the range between say all the conservative points, those four conservative points or the four elbow points. We have for each business in each year a range for the conservative point as well a range for the elbow point. Those are the figures there. We've also broken those down, so those were annual averages. We've broken those down for each retailer based on the specific retailer's definition of peak shoulder and off peak.

The costs have been decomposed in the following way, half hourly market costs in terms of both the spot price you pay for the load, as well as any contract difference payments are allocated to the corresponding period, based on the retailer's definition. Cap contract premiums are more like a fixed cost and it's the same problem we had with the LRMC, how do we allocate these fixed costs across the time periods. That was basically done pro rata according to how valuable the cap contract was in each period. So we looked at the proportion of difference payments back for a cap contract and split those between peak shoulder and off peak and hence allocate the cap contract premiums in a similar way. That's it. Thank you.

KEATING: Country Energy.

DE LORENZO: Thank you, Chairman. Justin De Lorenzo, Group General Manager Finance and Business development. Market based energy costs, as I said earlier, that's the most appropriate basis for determining energy costs as part of this determination. Just a bit of a scene setter, obviously, as everyone understands, ETEF represents a perfect risk free hedge position that's a starting point for retailers. Of course as ETEF falls away, retailers will be in the market purchasing energy for regulated loads through various hedging arrangements. So it requires a transition period to allow the market and also the retailers participating in it in terms of their hedging strategies to adjust to this new situation and it reflects the requirement under the terms of reference for the Tribunal to recognise hedging risk management and transaction costs faced by retailers in the absence of ETEF.

In our view energy purchase allowances need to include a risk premium that reflects the transition to an efficient higher risk hedging strategy, that proposed by Frontier, adopting a prudent and sustainable risk management approach. It's our view that it is a big leap of logic and unrealistic to assume that retailers will move from the current risk free position which they've enjoyed under ETEF and previously vesting contracts for about 10 years, in covering their most volatile load, which is the regulated load, to a higher risk strategy from day one, which is what's being proposed in the Frontier report.

Frontier also says that the most conservative point is at or below the energy price included in the current determination. So in other words, our understanding in terms of the way it relates to Country Energy, Frontier anticipates that we, Country Energy, will assume both higher risk and accept lower purchase energy cost allowance than those that currently apply. So we're being asked to take increased risk, reduced allowance. It doesn't make any sense to us and it doesn't in our view support a sustainable retail operation.

Just looked at in another way, and again coming back to the competition perspective, they're the terms of reference and again the policy aim of reducing customers reliance on regulated tariffs and the effect of the determination on competition is key. There was a discussion in the Frontier report about the risk of under or over estimating energy pricing and there was a view put, and our view is that underestimating energy pricing, whilst it may deter competition and may threaten standard retailers sustainability, two key risks of underestimation, concerns have also been stated the overestimating energy pricing could lead to barriers of entry and whilst we think that might be valid in the short term, we think it will be corrected by competition. So that's one key risk which we think will self correct.

Therefore, the impact in our view of underestimation in this area more than outweighs the risk of overestimation. Accordingly, we think the Tribunal should favour a conservative position, in our view more conservative than the conservative point in Frontier's earlier analysis, reflecting a transition by retailers to an efficient hedging strategy over time, and in our view that's probably even longer than the period that we have for this determination, and also in order to promote competition. Thank you.

KEATING: Thank you. Energy Australia?

MOODY: Thank you. Phil Moody again from Energy Australia. I just want to start by addressing a couple of issues. Firstly, Energy Australia don't subscribe to the view that prices need to go up to encourage competition and I suspect the Tribunal think that's a fairly circular argument as well. As well as being pricing manager, I am a consumer as well and if the prices are that cheap, then I don't particularly need competition to make them more expensive so I can choose someone else.

However, also as a consumer, I like the lights to be on and I'm willing to pay for my energy, such as it's worth, and to our mind the real issue at stake here, and it affects consumers as well, is whether or not we're going to get the next required level of investment in New South Wales, because if you don't get it, the lights won't be there and you might have a nice, cheap price, but you'll have it for 99.5 or 95 per cent of the time, not 100 per cent of the time that you have now.

So I'd just like to stay away, in our part at least, from any argument about needing higher prices for competition, because we could do quite nicely without competition, we had a lot of customers to start with and unfortunately it's a side effect of this whole process that making the prices cost reflective will encourage competition, and that's something that we understand and are happy to live with, but it's certainly not the main focus of our objectives.

I would also just like to mention that New South Wales currently has the second cheapest prices in Australia and incidentally, Australia has some of the cheapest electricity and energy prices in the world. So to the extent that we're recommending that prices do need to go up and above where they've been recommended thus far by Frontier, I don't think that we're planning to send anybody broke. Furthermore, I think as a consumer I'm happy to pay for what's required, but we also recognise the needs of vulnerable customers as well, and we believe that they should be addressed through targeted programs to assist vulnerable customers and that they are far more efficient in delivering both the funds to funds the investment as well as look after those specific subset of customers.

What I'm going to talk about here is as much about risk as anything else, because that's what our businesses pretty much have to deal with, and in particular there is a focus, particularly later on in the day, on the margin and the risks that are captured or recognised or allowed for in the margin. Most of the risks that you're going to see here are termed, I believe, non systematic risks and therefore are not captured in the margin, and I think I'll be able to demonstrate these risks here certainly swamp anything that's been considered to be a systematic risk.

Interestingly enough, I will talk about this graph some more, but I believe - and I'm not an economist unfortunately, so I may be out of my depth here, but I believe that one of the arguments behind or one of the premises behind a diversifiable or non systematic risk is that it is indeed diversifiable. I'd like to make the point that - and I think it's been suggested that you can diversify your risk in this case by buying an anti-correlated asset such as a generator or something - indeed a firm hedge is arguably an even better anti-correlated product than a generator, because you don't have issues with outages and what have you, be they forced or what have you, or if you happen to have a bushfire burn under the transmission line which is connecting you to the rest of the NEM, which I believe happens from time to time.

These graphs represent a portfolio exposed to the spot market which has been subsequently hedged, and I'd just like to make the point that you can still see substantial volatility and variation in these curves. So even to pick on the elbow point there for say, the green curve, I think the standard deviation there is around about $2.50. If there is indeed a distribution of outcomes around that mean of it looks like around about $47.50, you would have three standard deviations of that, either side of the mean, to take account of the possible outcomes that you could have, and therefore you're looking at deviations of plus or minus up to $9 a megawatt hour, assuming there's no asymmetrical skew in the risk, and in broad terms you could roughly equate that $9 to probably close to 8 or 9 per cent. Just to put some context around the actual diversifiability, if that's a word, of the risks, because the inference I think is that the risks that aren't captured in the margin can in fact be removed in other ways, and in fact I think this graph actually tells us that they can't.

One other point I should make, there's been a little bit of discussion about competition and I believe that there are two keys aspects of competition that are relevant and it depends on which question you're asking. I think in relation to Karen's point, the level of competition and whether or not LRMC is relevant is more about competition in the wholesale markets. I would suggest without a word of doubt that there is loads of competition in the wholesale market, I don't think that's an issue, but you know, it's certainly worth exploring if the Tribunal feel that that's relevant. To the extent, for example, if it is a risk that the energy costs allowance were to come out too high, I would suggest that that would be competed away quite quickly in the wholesale space.

The other area of competition is obviously in the retail space, which is of specific concern to the Tribunal insofar as whether there are certain segments of customers that are protected or exposed or whatever, and that is quite different in nature. It relates to the cost of getting to customers and whether customers are intrinsically attractive and things like that, and it certainly is I know an area that the Tribunal is looking at closely.

On to my presentation. I just wanted to make the point here, the large shaded circle sort of represents, I'm presuming, somewhere in there Frontier's report is suggesting we move our position to. The circle on the left effectively shows where we are now. In today's dollars, the ETEF for Energy Australia is around about that level and also in the current determination IPART have determined that we should earn a return of 2 per cent for that component. In the context of this report, I believe Frontier have said that in moving from the ETEF to this other position, that we're allowed to earn something like another 3 per cent in the margin, and that's intended to cover our non-diversifiable risks or systematic risks.

What I'm probably going to talk to you mainly about here is how many other risks are still left. I should make the point, and it's not necessarily to scale, but some of this risk is indeed captured in the margin. It's not clear from the report how much, although in the report's own words it seems to be very little. So most of the movement from the left-hand axis to that shaded area is considered non systematic risk.

Frontier have been quite open in providing the resulting portfolios, that's one thing that you can't really see from this graph, but we talk about this Frontier and the question is what does that world look like. Fortunately or unfortunately, it looks quite different to the way that we hedge our portfolios at the moment and it certainly sits outside the risk limits that both our energy risk policy and Treasury's guidelines would permit today. And I would argue outside the general commercial prudence of managing the risk in our business. By way of example, particularly on the elbow point, the portfolios that were produced as optimal oscillate every quarter between sort of 90/10, being cap and swap to vice versa. We're talking about the regulated load, which is essentially bid into the market today as a swap and represents about 25 per cent of the New South Wales state load. Pulling that out of the bid stack and putting 90 per cent of it back in as a cap, then you're going to get quite - without going into the details of that, it's probably safe to say that any history we have with spot exposure would be quite different.

It's probably time to move onto the next slide. Here we'll look at estimation risk. It is discussed in Frontier's report in the section on margin. Estimation risk is just looking at in this case estimation of price, the level that you think the price is going to be. In the words of the report, it suggest that this is something you can manage and diversify or understand and it relates to your ability to interpret the information.

Just from more of a layman's perspective here, each one of these lines on the graph represent somebody's view of the forward market. I'm not going to comment on whether they're right or wrong, in fact in some ways that's reflective of the problems in our business, that there is no right or wrong, you're trying to build a portfolio that is robust and can withstand a range of outcomes, rather than a portfolio that will handle a handful of outcomes really well. You can see here that across from the green curve to the black curve there's something in the order of $4 to $5 a megawatt hour difference straight away, which is 10 per cent of the energy cost.

Equally, there's also variances in the resulting standard deviation, so if you pick the elbow point or the conservative point off the green curve, it's around $2.50, if you pick it off the black curve, it's closer to $3.50. So straight away estimation risk is quite considerable and I would argue much bigger than anything allowed for in the systematic risks.

Just related to I guess that estimation risk, and this was touched on earlier, the forward market for contracts, so if this was, I think this was calendar 07, that's a graph I took a few months ago. At the time the contract time had traded at a peak of $41.75. It did indeed continue to climb into Q4 and in the past couple of years we've had reasonable spot price volatility in Q4 which has driven demand for contracts in that period. What we've found this year is that there in fact wasn't any spot price volatility through Q4 and had I brought it with me, you would actually see that this contract price fell about $3 a megawatt hour, fell into the high 30s. But there's nothing like a bit of hot weather around the NEM and a few bushfires and a couple of other events to now see the curve heavily bid and it's actually rallied above this level now, so it's now back up above this level, it rallied about $4 a megawatt hour.

My point is that the contract market is - those curves that you saw on the previous page are arguably everyone's opinion based on a given day. Here's how it moves across a range of days, so if you've now got a whole range of market participants, here's a new dimension of uncertainty. A business can normally cope with this, by the way, because we would normally buy and sell in the same market. So we would buy in the wholesale market and we'd sell to retail customers at the same time, and so we would attempt to insulate ourselves from this particular aspect of risk. Unfortunately in the case of this determination, it's attempting to fix a price or a formula for a price that will appear or occur over a three year period. That's equivalent to me agreeing a price with all of my regulated customers today without having a wholesale hedge in place on the other side. That's not how our businesses normally operate. So in the context of this determination, this is a risk that I normally have a way of managing, but I don't in this particular case.

If you just pick the four conservative points on this chart, each one of those, as you can see, has a mean price, which is shown on the left and then a standard deviation around it. This graph is like taking a snapshot through there and showing the standard deviations and what have you. There's four views, each with a mean and a standard deviation and this is what happens when you combine them all. So the yellow area is what it looks like. In short, the mean is pretty straightforward, it's somewhere in the middle of all of them. The important thing is that the standard deviation is greater than everything you had before. That's just a brief point.

The curves that we've seen are all mean curves, they're 50 per cent POE, so you've got equally, assuming all other things being equal, you have equal chance of being above or below those outcomes. The terms of reference require that this price that we eventually come up with ensure that it covers the costs and risk of this business and I would argue that the 50 per cent POE doesn't ensure that at all, it's a halfway bet, but it doesn't actually cover that. Working along here, by going out one standard deviation, it's probably first year statistics or something, you can get to a 16 per cent POE or conversely an 84 per cent confidence interval that you've now covered. All of those points in this case would have moved us from $52 to $56 and even at a 97.5 per cent confidence level, that would take us up to nearly $60 a megawatt hour.

I just wanted to make the point you can then show those on - this is an estimation, by the way, Danny, I haven't stolen your numbers. The pink line I've drawn on there reflects, if you like, the culmination of the four curves that are there in terms of mean and standard deviation at the 50th percentile, and these other curves reflect, based on in principle the same information out of Frontier's models, where the curves would sit if you're looking at those other levels of confidence. I think that's quite important given the size of the risks we're dealing with and that there is no other means of compensating for them.

In short, we believe that - again Danny and Frontier have been quite thorough in the models themselves and they've been through them with us as to the mechanics of them and we don't have an issue in particular with the models. We do have, I think, an issue with some of the data that has been put into the models and I think we, retailers, can't be blameless in that exercise. But we'd certainly encourage revisiting the input data, and to pick on a couple of examples, obviously I have significant concern about the load data used. That should be a fairly deterministic process, I don't think it's an issue, just clearly the results look a bit odd.

Also there's the issue of the spot price forecasts that have gone into this model in determining the optimum portfolio. There is more than one, but I guess we were asked to give a spot price forecast and we did that. As far as I know, all the businesses gave a single half hour time series. Having seen now what it's been used for, that's not how we would run our business. If I could just explain that a little more, as I mentioned earlier, the issue for our business is about controlling the uncertainty of the product you're buying so you can sell it to your customer. So creating a portfolio that is optimal for a limited or finite set of circumstances is not of great use. What you need is a robust portfolio that can cope with some significant extremes.

Just to put some relevance around that, we've had VoLL events in Victoria in the last week or so which incidentally didn't relate to shortages in generation supply, they related to the non firm nature of generators being able to connect to the network, which is not priced into our market, and in fact the price was set to VoLL as a result of load shedding because those generators couldn't be dispatched. So there is things other than just the level of loads that cause VoLL. The price outcomes in New South Wales were significantly different and a portfolio that worked well in New South Wales last week would be quite different to the best one that was in place in Victoria, and I've probably ask you what's the weather going to be like next week and what are the chances of what happened in Victoria switching over and happening in New South Wales. That's the business problem that we have to deal with. We need to set a portfolio that will not bleed us to death when we don't have high prices and won't burn us when we do get high prices like just happened in Victoria through foreseen or unforeseen events.

Generally the estimation risk which I mentioned, both in terms of the contract price movement and also different businesses' view of the world, I don't believe is diversifiable. It's a risk that we do have to deal with and we can't give to anyone else and these risks, such as that one, are quite significant and far greater than anything that's been captured in the retail margin. Also the point that some of the portfolios that have been generated through this process are untenable in terms of the risk that they would require our businesses to run and the consideration of whether we should be looking at a 50th percentile or confidence interval or something more robust in terms of ensuring that the costs and risks or our businesses are captured. Thank you.

KEATING: Thank you. AGL.

FOWLER: Thank you, Mr Chairman. Much of what I was going to say has already been said by Energy Australia, but I'd certainly summarise many of the key points that we believe are very salient in that previous discussion. Probably the first point, it's not as profound as with the long run marginal cost calculations, but we were certainly surprised by some of the relativities in pricing. They don't seem to be outcomes that we expect when we actually price these loads, albeit it with different mechanics. Probably the most startling difference for us would pertain to Integral, where we just believe there's an underpricing going on there and it does not reflect the cost that we would expect to incur by going to the market and constructing what we would consider to be an efficient portfolio to hedge what we considered to be the most peaky and volatile load that we have in our various portfolio of mass market customers.

Much like Energy Australia, we are concerned that there has been no specific allowance for certain risks that are inevitable in the market place. For us it is difficult to construct an efficient portfolio at any one point in time, for a number of reasons. One of those reasons is pertaining to weather and general load outcomes. Actually, there are two types of risks there. One of course is the incredible asymmetry that we see in pool price outcomes under certain conditions. I always wonder to myself what would have happened to the pool price on New Year's Day last year when we had a 45.1 degree day in New South Wales, and if that had happened on a Wednesday in the middle of February, I think it would be safe to say that we'd be at the cumulative price threshold and all of the retailers would have incurred some very, very serious damage to their portfolios.

But even aside from defined outcomes, there's this whole issue of actually being able to forecast your load. For example, in Victoria we had a situation and in South Australia to a smaller degree, whereby up until last year we knew that there was a very rapid increase in people installing reverse cycle air conditioners and we knew that that would result in more peaky loads than we'd ever seen before, but we never experienced the weather to actually know what that particular effect would be. You don't actually know what it is until you actually get there. So this whole issue of being able to know what your load is, not today or tomorrow, but when you hedge, you worry about next quarter or next year. That level of uncertainty makes it very, very difficult to construct a theoretically efficient portfolio.

We also know that the shapes of these loads are changing for a number of reasons. One is reverse cycle air conditioning, they are getting more peaky. We also know that loads are changing as a result of cherry picking. The net system load profiles are for all intents and purposes a massive cross subsidy and it's very, very natural that people who have a cheaper component of the net system load profile will choose to switch to a smart metering solution and therefore cherry pick themselves out of the net system load profile and what's left becomes more peaky and therefore more expensive. This is yet another challenge, if you like, for us maintaining and efficient portfolio.

You spoke about the VoLL events that we experienced in Victoria as a result of the transmission outage. Well, we've seen more events this week in Queensland, very, very similar things caused by network constraints, if you like, whereby basically VoLL events occurred in Queensland, New South Wales had almost no capability to export into Queensland and in actual fact this bizarre physical market that we live in was actually sending high priced Queensland electricity into New South Wales at certain times. These are the kind of things that make it just incredibly difficult for you to maintain an efficient portfolio.

Another general concern does pertain to the fact that we do see some issues with regards to the relativities and we don't know if that's a function of the loads that have gone into the calculation or the pool prices, but certainly they do seem to be slightly divergent with what we expect, in particular in relation to Integral Energy. Just to restate the point that I made in the previous discussion about long run marginal cost in relation to green energy, we certainly believe that the wholesale market for green products is a furphy, it doesn't reflect the costs that a large retailer would have to incur. You certainly cannot build renewable projects on the back of the $18 REC prices that you see on screen today. No question that some retailers have had the opportunity to benefit from those in recent years, but you could not build a large sustainable retail business off the back of those mandated costs, given the costs of renewable energy. That's it, thank you.

KEATING: PIAC.

WELLSMORE: Thanks. I have to say just from a personal perspective, I suppose, on public policy, it's just interesting to sit in these sorts of events and listen to the descriptions and the listing of the many, many difficulties and complexities that come out of competitive energy markets. I'm not surprised with those things, but I do sometimes wonder if it gives anybody pause for thought of whether we've made the right decision to get into these environments. I mean, they're much more transparent, we're told, but you know, I'm buggered trying to understand how they work. But I don't get paid for that necessarily, so that's fine. I have to say I'm really fascinated, I'd love the find the residential or small business customer that actually knows that they're sitting above or below the net system load profile and consequently approaches the retailer and says sign me up, please, because I know I can save money because I'm 10 per cent above or below the net system load profile. If you can find them, good luck.

I think actually the point was really well made that at the end of the day, from a public interest point of view, keeping the lights on probably is a priority more than competition, I mean, certainly from PIAC's point of view, keeping the lights on is a priority, certainly compared with, for example, the idea that we could have greater levels of competition in the retail area. That goes back, I suppose, to the point I made earlier about we're somewhat accepting of the argument that costs do need to go up some degree, you know, just to ensure there is investment coming on. I suppose it underpins the first comment I made this morning, that PIAC is rather attracted to the LRMC approach.

The last thing I want to say at this point though is that I think it's probably useful to explore, and we don't really have time today, but I think it's useful to explore the relationship between competition and risk. I just wonder if there's a bit of a feedback loop that comes into play at times. As competition becomes more intensive and there's greater churn rates, retailers actually face a greater risk and my observation is that they tend to manage that risk by a variety of approaches, including an aversion to longer term contracts. I stand to be corrected on that, but I suppose that's how I understand that it works.

Our friends from the generation sector then obviously see a risk and they, I imagine, would try to manage that risk, and one of the ways that they'd do that is to actually charge a higher price. So what you get is more competition actually creates more risk, more uncertainty and I suppose our concern from PIAC is that that in itself then just adds to the costs and adds to the prices that the end users are seeing. But no doubt the market participants will have their own way of understanding how those risks actually are derived. Thanks.

KEATING: Integral?

WALDMAN: Karen Waldman, Integral Energy. Just before I start on our prepared presentation, I'd like to acknowledge support for both what Energy Australia and AGL have commented in relation to the relativities between Integral and Energy Australia. Clearly Integral Energy obviously were also surprised by those results. We do understand that we have an extremely peaky and volatile load and so I suppose our concern whether that is a feature of the input of the data and we'd be looking to similarly include some further information on that in our submission.

Secondly, I'd also say that we agree with Energy Australia that the risk under these results that the business would be expected to run, would be untenable nor necessarily comply with our board guidelines. So if we see the costs that Tony put up, I won't go through those again, but in endeavouring to cover something slightly different, we did calculate the energy purchase cost allowances that Integral requires to ensure cost reflectivity and we used three methods to market test the cost for our regulated load. For example, getting some quotes and doing a statistical variance analysis using market data.

Based on this analysis, we believe Frontier has not adequately considered the costs of hedging the Integral load, and that includes those issues that EA talked about also in relation to costs related to shape and volatility of our load in particular. Integral's load cost distribution is substantially skewed and one can't assume a normal load cost distribution in this case.

Also the impact of extreme events and the impact of the inter-temporal issues, looking now at contact market prices three years out. When we adjust for the impact of the controlled load, we still get a price greater than the top end of the conservative price range proposed by Frontier, so I guess we'd agree with Country Energy that the conservative is not conservative enough. In fact, having looked at the range and depending on where you take the result, if you go with those figures, Integral would be exposed to a shortfall of somewhere between $31 million and $163 million over three years if we were to get one of those sorts of results.

Then let's look at some real life benchmarks that exist out there in the other states at the moment. They also all show costs significantly above the estimates that have been provided. So there's been a CRA report for Victoria which recommended as a mid point of reasonable range for wholesale costs figures in the range of 59 to 60, and ESCOSA having much higher results obviously.

What we're not saying is what the right answer is, but I think we need to be realistic in what the businesses require for viability and perhaps some of those other results across the other states for costs are one of the features that contributes to greater competition, because clearly if one doesn't get a fair market price, that would be a barrier to entry of competition. Thank you.

KEATING: It's now open to other questions and comments from anyone in the audience.

HAMILTON: ..(not transcribable).. the conservative point is a reasonable sort of price ..(not transcribable)... One thing though, in terms of ..(not transcribable).. [comment that elbow point is not and that it would be outside risk limits of a retail business]

PRICE: I'm just surprised, Karen, that you didn't put California in there. It's just as relevant as South Australia and Victoria. I don't think they're very useful benchmarks, by the way. I think one of the key things that have come up in everyone's talk is about the surprise between the relativities between EA and Integral and you've got to believe that we were surprised, that's not what we had imagined. I think there's a sort of conventional wisdom out there and it didn't fit with our convention wisdom.

We spent, the Tribunal knows, a lot of time trying to understand what was going on and Integral knows and EA knows that we spent a lot of time trying to look at it. Initially we thought it was the fact that EA had inadvertently left the smelter in the load profile, that certainly was a contributing factor. I don't know if that's widely known, but its removal has evened things up a fair bit. There were potentially other things that are going on which, you know, the distinction between net system load profile and controlled load profile, which is hard for everyone to observe. There's other things such as the removal of [embedded?] generation. They're all factors that we had a look at and we spent some time looking at sort of historic patterns versus the forecasts to look at the consistency between those.

We've gone through those checks, but I'm more than happy to concede that there's something else in there, because like I said, it didn't fit with our expectations, but having gone through those checks, that's what we've ended up with and both Integral and EA have been part of that process. So if there's further information that comes to light or something that we've missed, I'm more than happy to take that into account. But I just want everyone to know that you know, it wasn't something that is sort of a surprise today. Some things have been a surprise along the way, but we know about this and if there's something that people think we've missed, let's take it into account.

That was a very good thesis, by the way, Phil. I think Phil did a pretty good job of explaining how those curves could be interpreted and most certainly you can use the standard deviations to calculate all sorts of measures. Everyone's done some basic stats, that's why we provided it, so you can see that there are distributions around it. The entire technique is designed to help people understand what sort of risks are underlined there. So we've got no problem with the way you interpret it, but I guess as a general point, the Tribunal has got before it the difficult job of balancing the interests of customers and a market which might not be completely competitive, hence the Chairman's desire to understand a bit more about the competitive conditions in the New South Wales market, because that helps their judgement as to whether they need to do a harder job in protecting customers or whether the competitive market will work in their favour.

We made it pretty clear in the report that these curves are not, you know, there is a standard deviation, it's not like ETEF. We've made that absolutely clear, the standard deviation is more than zero, and there's risks associated with that. I'm not going to deal with the treatment of risks in the margin, I'll get Steve to do that later on. I think he'll adequately respond to that. But I think it's important to understand that when we formulated these curves, we formulated these curves for a particular load, as if it’s managed on a stand alone basis. So it's completely unsurprising that when you get the out-turned results, they don't look like what you're doing, because what you're doing, your reference point is managing a much bigger load, CNI customers, different types of characteristics. We're not in that world here, by virtue of the terms of reference. So we're not going to end up with a portfolio that looks like what you do.

Further, we've used a limited range of products to hedge. Again that means that we're not going to end up looking exactly like you, but let me tell you this, that if we add more bespoke, exotic, refined products, that curve will come much closer to the vertical axis, ie, it will reduce the risk. It might do it at greater costs, it might do it in fact at lower costs. Generally we find in this type of approach that as you have more instruments, there's more opportunities to mix and match, more efficiencies, costs tend to go down. So you've got to be careful about arguing for more realistic hedging products, because it might be that you don't like the results. So there's a few extra things to keep in mind when interpreting the results. There's one other thing.

UNIDENTIFIED MALE: ..(not transcribable)..

PRICE: No, look, I can't remember it. I might come back to it later on, but it was in yours, Phil. Thank you.

KEATING: Thanks, Danny. Further comment and response to that? Yes.

MOODY: ..(not transcribable)...

PRICE: In fact it's not you, Phil, it was in fact Justin, sorry about that, you look very similar. It was exactly on the ETEF point. I think the reason I thought it was EA, because EA had a picture up there and revealed that the ETEF cost was about $50 and I think similarly Justin showed that.

I think part of the problem here is that the ETEF price, the way it's been implemented by Treasury, is that it's a uniform price, and that creates all sorts of problems when you come to - so that's uniform irrespective of geography and load type. Now we're in a world where we've been asked to recalculate prices on the basis of the particular load characteristics of each retailer and you've got to be sure that there's going to be some differences, and there was always a chance that somebody was paying a little too much. In some senses that's what's happening here. So we're a little surprised by that result, but they are the numbers. I guess it gets down to questions about the appropriateness of the modelling technique and the data applied to that modelling technique and more philosophical questions about just how much risk the business should be bearing. So I think they are other considerations for the Tribunal.

KELLY: ..(not transcribable)..[Query reason for decline in real terms over the regulatory period]

PRICE: I don't have a - I think the public report had the estimates from the businesses on spot and contract prices and you'll note that they are all actually declined over time, so perhaps you should ask them.

UNIDENTIFIED MALE: ..(not transcribable)..

KEATING: Any other comment? I won't necessarily prolong this session. I'll just make a few remarks from the Tribunal's point of view. I was going to begin by emphasising the - well, I could recognise your difficulties in coming to grips with this. I just want to make one comment nevertheless. I may have misunderstood you, but I drew the inference that you were suggesting that it was a move to a market that was creating this risk and uncertainty and I don't think that's quite right. The risk and uncertainty is to do with things like weather, a hot day, which is very difficult to predict. The issue then becomes what is the best way of handling this risk and uncertainty and who should pay for it.

It seems to me that to sort of, if you like, judgements about hedging and so on that market operators are making, in the absence of the market, the regulator is trying to make it. In the long run I would like to think, I mean, I'm pretty sure that the market operators will do it better than we do. Now, the question then is whether there are other factors that govern how quickly you move to a market, but if you can move to a market, then there's real advantage in doing so.

WELLSMORE: I guess I'd say, it wasn't necessarily this, I mean, I'd agree with you to an extent, I'm not necessarily saying ..(not transcribable).. was of great use to businesses and certainly to consumers. I guess my point was more that the way the risk might have been managed 10 years ago was perhaps a bit of a ..(not transcribable).. but I'm not sure the ..(not transcribable).. any better off understanding the relationship between hedge costs and ..(not transcribable).. But I'm certainly not saying ..(not transcribable)..

KEATING: Look, I think the critical message we've heard this morning is probably just how conservative business should be in operating in this market, partly driven by, if you like, the regulation, not just driven by treasury regulations or whatever. And I got the sense that there wasn't a lot of support for the elbow point. One person that seemed to support the view that Frontier have got the conservative point right, didn't then support the elbow point. But I think the sense was that we were being invited, that there were reasons for being more conservative than the conservative point.

Related to that is also the question of whether there are non systemic risks or systematic risks that can adequately be handled through diversification and so on and including the point about estimation risk. They are things that I think we'd want to think about further. The critical issue is the overriding thing, just how conservative we should be in managing these risks and how that can be built into the price. We'll be taking that on notice, it clearly is an important issue.

We've made very good progress. It's probably better to break. We'll have a break now and resume again in about three quarters of an hour's time.

LUNCHEON ADJOURNMENT

KEATING: Thank you very much. We might get underway again. The first topic for this afternoon is Retail Costs, and as consistent with our practice this morning, we'll get Frontier to do a presentation first.

HARPHAM: Thanks. My name is Andrew Harpham, I work at Frontier Economics. I'm going to be talking to you briefly, as Michael said, about retail costs. I'll just go through very briefly about the approach we took to estimating retail costs and then present our results, which are all in the report.

First, briefly, to review the terms of reference, which I'm sure you've already seen, the terms of reference require consideration of mass market new entrant retail costs and they define a mass market new entrant as a new market entrant that is of sufficient size to achieve economies of scale. That's fairly broad and still leaves a lot of interpretation as to the exact nature of a mass market new entrant.

In interpreting the terms of reference, we've considered what we think is most likely to happen in practice, and that is that a large retailer operating elsewhere in the NEM but without significant operations in New South Wales would enter the mass market in New South Wales. We've considered the mass market new entrant is most likely to be a stand alone electricity retailer, so not horizontally integrated into gas retailing, and we've also considered the retailer to not be vertically integrated into distribution or generation.

Broadly speaking there's two categories of costs that a mass market new entrant will face. There's firstly the costs of acquiring new customers as it enters the mass market, and secondly, the retail operating costs of serving those customers. So we've estimated both of these and again broadly speaking, we've taken two approaches to estimating these costs.

I'll go back one. The first approach is the bottom up approach, where basically we rely predominantly on information that we receive from the standard retailers about the different quantum of costs for different elements of both customer acquisition costs and retail operating costs and have built that up into an estimate of the total retail costs that a mass market new entrant would face, and the second was benchmarking these estimates against allowances, particularly in other regulatory decisions.

Turning first to customer acquisition costs, the range for customer acquisition costs is based on three things, the total cost of acquiring a new customer, which is amortised over the expected life of a customer at a discount rate. Now, the total cost of acquiring a new customer that we used in estimating the retail cost is based on estimates for each of the standard retailers provided. As set out in the report, there's quite a degree of broad consensus in those estimates, with one or two exceptions. The expected life of a customer is based on in part again the forecasts provided by the retailers in their responses to the information request. Also we took a broad view of the way that competition is happening in a variety of markets in Australia and overseas and looked at the implications that has for average customer life. The discount rate which we used of 8 per cent is based party on previous decisions by IPART and ESCOSA and also on a comparable firm analysis.

Turning to retail operating costs, the range for retail operating costs is basically based on information provided by the standard retailers. They provided estimates of the costs they face in retailing to small customers, which has been benchmarked against information on retail costs from other jurisdictions and allowances in other regulatory decisions.

The standard retailers provided both historic retail costs and customer numbers and forecasts of retail costs and customer numbers. In the recommended range that we've proposed in the draft report, we've given greater weight to the historic estimates of retail costs and customer numbers, again as set out in the reports, just basically because of observations we made about the relationships between fixed and variable costs on the one hand and customer numbers on the other hand in those reported forecast costs, which we don't expect you'd see in reality.

In terms of results, for customer acquisition costs we have different recommended range for residential customers and business customers. This is basically due to the - sorry, it doesn't say it on the slides there - this is due to the different expected life for a residential customer and a business customer. Based on information we have, we thought it likely on average that you retain a residential customer longer than a business customer, so in the first bullet point there you see the recommended range for a residential customer is between $25 and $30, whereas in the second bullet point, it should say business customer, it is between $40 and $45. The range we recommend for retail operating costs is between $60 and $80 per customer per anum.

Putting these together to form a view on the total retail costs a mass market new entrant would face, we came up with the recommended range as between $85 and $100 for a residential customer, again that should say, and $100 and $125 for a business customer. In coming to these views, we also did consider the results of benchmarking against other regulatory decisions, which you see here. These grey bars represent the ranges for retail operating costs in other regulatory decisions, converted into 2006/2007 dollars, so they're consistent with our recommended range. That range there is just the operating cost component of the retail costs. We think that comparison is useful because it's not clear in these other regulatory decisions that they've included an additional allowance for customer acquisition costs. But this second slide, that bar at the top there includes both the retail costs and the customer acquisition costs. We've weighted the residential and business customer acquisition costs by the number of the customers that you see.

You can see that on the previous slide the recommended retail operating cost is a bit below some of the more recent allowances in regulatory decisions, whereas if you combine them both, it's above or within the range for other regulatory decisions. That's all I have to say on retail costs. Thank you.

KEATING: Phil, I think you're first cab off the rank.

MOODY: All right. Thank you. Phil Moody from Energy Australia again. Thank you. Michael.

You'll be glad to know I don't actually have a great deal to say about this one. I might take the opportunity just to respond to a couple of things that were said earlier initially. There was a comment about the Energy Australia net system load profile and yes, it was changed, and I think I addressed this a few months ago in September, but I would just like to make the point that that change was indeed a correction and I don't believe anyone has actually disagreed with the fact that the change that was made was actually required. It's not actually Energy Australia's' - although the profile relates to Energy Australia's network area, it's not actually our responsibly, it's calculated by NEMMCO and looked after by the jurisdictional metrology coordinator, just to clarify that point.

Another point which was made was in relation to the reference energy cost allowance under the ETEF and where we're moving to and there are in fact different costs that we're moving to, depending on which retail area we're talking about. That is in fact perfectly correct, however, Energy Australia, to the extent that Country and Integral, Integral is more expensive and Country is cheaper, on our analysis EA is around about in the middle. So ours is a reasonably fair reference point for the ETEF that's currently in use.

On that note, I will talk about opex. Firstly, I'll probably make the point that EA are generally indifferent as to whether costs end up in the opex or the margin, as long as they end up somewhere, and we respect the fact that they shouldn't be double counted, of course. Probably the main comment here, we probably have a different view on the customer acquisition cost or in particular the duration with which customers will remain with us, but we'll cover that in more detail in our formal submission. The other point is - which Andrew mentioned - that this analysis does rely to some extent on historical data from the standard retailers and we do believe that that is in fact different for a mass market new entrant. I'll save the rest of my time for the next section. Thank you.

KEATING: AGL. Thanks, Sean.

KELLY: Thank you, Michael. It's Sean Kelly, General Manager Energy Regulation for AGL.

Firstly, a couple of things, AGL obviously fits within the definition of the mass market new entrant as put up on the slide earlier and as a general principle, we fully support the proper allocation of operating costs and customer acquisition costs into this element of the price stack. It's fair to say that when we looked at the various component parts, the retail operating costs, we were surprised at the lowness of the range of the benchmark.

If I reflect back on our price review in South Australia where the regulator in that state, ESCOSA, went through a fairly extensive audit process in terms of looking at every general ledger account in relation to our costs and the allocation of those costs. At that time they came up with a benchmark for retail operating costs of $84. If you apply the escalation under that price determination, today's dollars, the equivalent would be $95 for the operating costs. I'm quite happy to go onto the record that in consideration of those operating costs, ESCOSA explicitly excluded any customer acquisition costs into that number.

In terms of just then looking at some of the principles that have been used in the calculation by Frontier, I suppose I've got a few questions or am seeking clarification rather than outcomes. There's a lot of discussion around fixed and variable costs, yet it's not clear how those fixed and variable cost considerations are actually derived into the final result. Some of the areas that I'm still confused and happy to be clarified is that on the one hand it talks about fixed costs becoming variable costs and should be moved out of fixed costs and therefore reduced, and on the same time, when they talk about the variable costs, they say the variable costs should be decreased and don't seem to give any consideration for the fixed costs that move into the variable costs bracket.

There's also some discussion around the conversion of those fixed costs using the consumption. It's not clear whether that consumption will be used to convert all retail costs to dollars per megawatt hour for pricing or whether it's only going to be applied to the variable cost. Obviously the average consumption that is used over the price path period becomes fairly critical in terms of when you're talking about dollars per customer, how you actually then generate a dollar per megawatt hour and the price.

In terms of the use of the historical average cost of the standard retailers, obviously in regards to one of the bullet points on the first slide, the difference between the mass market new entrant cost and the costs of an integrated retailer distributor needs to be taken into account, and yet using the average standard retailer costs seems to ignore that potential impact on costs.

Secondly, the average costs escalated, I presume that's CPI to bring them to 2006/2007 dollars, I believe those costs should actually be escalated by the changes in the cost drivers of those costs. Obviously a significant component is labour and labour cost increases have exceeded CPI, so if you actually brought prior years costs to the current day using the labour escalation rate, you would actually have a higher operating cost.

The other thing about using historical costs, obviously it doesn't reflect changes in the levels of service and expectations and changes in the industry in terms of operating in the market place. Obviously the roll out of interval meters increases costs to retailers. Provisions that retailers either voluntarily or through regulation put in place for hardship obviously add to the costs.

These are not necessarily recorded in the historical costs.

In terms of the customer acquisition cost, I don't propose to outline any specific numbers. I'm not sure if my friends would be eagerly writing it down, but it's fair to say that we have provided that information to the commission on a confidential basis. But I am surprised that the 10 year retention is the number that's used. We would expect it to be a lower number of years and obviously that then has a direct impact on what the dollar is per customer. That's it.

KEATING: Thanks, Sean. PIAC?

FREEMAN: Thanks Michael. Elissa Freeman from Public Interest Advocacy Centre.

As you may expect, I guess this area of the agenda is of particular interest to PIAC's constituents, being customers and with a particular focus on low income and vulnerable customers. I suppose the reason that we have a particular interest in this area is that there appears to have been, well, there has been somewhat of a change in the way that costs are being calculated at this stage and we see that that has somewhat detrimental impact to customers. In the past the Tribunal has been able to I guess avoid including headroom pricing in the way that retail prices have been set and in this determination, I guess inevitably what we see happening is headroom pricing being introduced into the retail price for customers.

In particular in this section I think that would apply to the customer acquisition costs. The retail operating costs are probably more in line with what we'd expect to see, they're not significantly different from the prices that have been determined in the past. The customer acquisition costs, however, are significantly different. We were thinking about what's happened in the past in this area back when full retail competition was introduced, a $5 allowance was made for customers. We're now looking at a $35 allowance I guess what's important about that is that it's being applied to the entire customer base, and while we obviously need to spend some time looking at the rates of churn and types of customers that are going to be benefiting from those costs, I think it's equally important to spend some time looking at the customers that won't be benefiting from that.

In other jurisdictions where you've had considerably higher rates of return, I think the flip side of that is there's also customers who have stayed with their incumbent retailers and have endured the higher costs associated with that. So essentially I think what we see happening is that the 'can’t moves' or 'won't moves' the customers that need to remain with the incumbents are facing a considerable hit in this price determination. In effect, we see the residential base that's probably the most vulnerable subsidising the competitive market, those customers who are able to move out of it. Having said that, we do acknowledge that in the past there have been some tariffs that have been under-recovering, some at a considerable rate in the past and while they've been slowly moving to cost recovery levels, we do acknowledge that there's a need for those under-recovering tariffs to move to cost reflective levels and I guess we see that as the role of the Tribunal to be clearly able to articulate what those appropriate cost levels should be.

Just turning to Frontier's analysis, we'd endorse the definition that's the interpretation of mass market new entrants. I think that gives a fair standing to the customers who are going to be remaining with the incumbents. I think it was important for us that this change in direction didn't come at too big a cost for customers and the decision to consider an established market for new entrants a scale that's comparable to existing retailers does benefit customers.

In terms of the retail operating costs, as I said, I guess they're roughly what we would expect. I know there was a comment previously that there's been some initiatives that perhaps don't reflect as well the costs going forward, particularly around hardship, and those are programs that PIAC has endorsed and we do see a great deal of benefit flowing to customers who have remained with the standard retailers. At the same time, I guess we also acknowledge that some retailers have been able to significantly reduce other cost components, particularly around complaints costs and the costs of managing bad debt. So I guess we'd like to see what other mechanism is available into the future to keep that pressure on retailers to take on what we'd see as mutually beneficial exercises for customers.

I suppose just lastly to finish up, there is some concern that remains around the customer acquisition costs and the headroom pricing that's going to be associated with those. Customers who are remaining with the standard retailers are generally customers that aren't able to access the competitive market. We see those as being primarily low income, low consuming and customers with a poor credit rating. In our view, any attempt to keep costs at a minimum would benefit directly to those customers. So in the absence of a spectacular change in public policy, the degree to which customer acquisition costs can be kept to the bottom end of their range are going to be of substantial benefit to customers in the next determination period.

KEATING: Thank you, Elissa. Integral?

WALDMAN: Karen Waldman, Integral Energy. I'm going to cover the retail operating cost component. Frontier has assumed the real operating costs per customer have been and will continue to be constant, however, Integral's underlying operating costs have risen and will continue to rise, suggesting that future allowances based on the average of the last four years is not appropriate. Interestingly, real increases in operating costs per customer are consistent with Ofgem's view that an increase in retail competition will increase retail costs. Frontier's recommended range of $60 to $80 per customer for operating costs is below, as has been said I think by AGL earlier, other Australian and international benchmarks and below Integral's current costs. And Danny, I'll only mention international and national benchmarks where we both have.

Looking at Australian benchmarks, what we see here, and we've excluded the previous IPART decision, because really you can see it almost with the mid point of the Frontier decision is exactly the same. But what you see here is the recent regulatory results have raised from somewhere in the mid 80s up to $100 per customer, with the average at about $94 per customer, I think, which is pretty close to what AGL was saying earlier.

Looking at the UK, Frontier have justified the reasonableness of their estimates by examining some 1997 and 1998 data from the UK from Ofgem. However, there is more recent Ofgem data available and they have actually rejected the use of pre 2000 data as a benchmark for post contestability costs. More recent Ofgem data, which we have confirmed with Ofgem, suggests operating costs of $120 per customer, an increase of 80 per cent on the 1997/1998 figures reported by Frontier. So clearly that data supports a level of operating costs well above Frontier's estimates.

In summary, whichever benchmarks you choose to use or look at or use for advice, it's clear that compared to any relevant benchmark, the Frontier range is low. Thank you.

KEATING: You're not going to talk at all about customer acquisitions?

WALDMAN: No, we'll do that in the submission.

KEATING: Okay. Thanks. Country Energy?

ADAMS: Thank you. John Adam, Group General Manager of Retail with Country Energy.

Many of the points that I'm going to comment on have already been addressed by other speakers, but I do have, I think, a couple of different angles. We will be saying to the Tribunal that the operating costs that are reported are not inconsistent with Country Energy's experience to date as a standard retailer, but just a caution that they are increasing. I think it was Sean that mentioned changing standards, increased communications with customers, as well as the point that I'm not sure that anyone else mentioned so far, is that with customer numbers reducing, obviously the average cost to serve does increase.

I would also caution that a mass market new entrant may face a higher level of costs due to the inability to share costs within an established and diversified business. So comparisons with existing New South Wales standard retailers does have its limitations.

Similarly, the cost of acquisition are not inconsistent with Country Energy's experience to date. However, like many others, we do have some quite severe concerns about the expected life of a customer and that it has been overestimated. We will be providing the Tribunal with further detailed comments in this area, but just to caution again here the danger in overestimating the life. We've also as a result of the report commissioned our own advice on the discount rate and I saw a copy of that this morning, and obviously we will be providing it to the Tribunal, but I can foreshadow that it suggests that the appropriate range is between 8.1 and 12.8 per cent. Thank you.

KEATING: Thank you. It's now open for comment. You go first. I'll let you choose, or you can wait until you get a few other comments. We'll go to other comments or questions from the floor. As you can see, we've got a roving microphone now, because apparently this morning it was a bit difficult to hear people who are not at a microphone. So comments, questions? While they're collecting their thoughts, Andrew.

HARPHAM: Just a couple of things to say in response. Firstly, about the issue of whether retail operating costs should increase over time, we formed the view that they shouldn't, based on two things. Firstly, Country mentioned that there was some danger that customers would be stranded, which is certainly a possibility for the standard retailers, but we don't think that's likely to the same extent for a mass market new entrant, they don't have this existing base of customers to which they've scaled their retail systems, so they don't face that same stranding problem. But more importantly, we also looked at the historic information that we got from each of the retailers and looked at how that had changed over the four years. I think we asked the retailers for information from 2002/2003 up until 2005/2006, and the evidence didn't support the view that retail operating costs increased over that period. So we thought that supported the view that they probably won't increase over the next three years either.

In terms of the additional costs that a stand alone retailer might face as opposed to a retailer and distributor, we have given and will continue to give IPART some advice on that. A lot of that is based on information that has been confidentially provided, either by the retailers or other parties, but we are aware that there are reasons to expect that an integrated retailer distributor like the standard retailers will have lower costs than a stand alone retailer.

In terms of, I think each of you mentioned the assumptions we've made about customer retention life. We're happy to hear any other views that you have and in particular any other information you have that will shed light on how long a customer would be retained is more than welcome, and once that comes through in the submissions that you make, we'll be happy to consider that. I think that's all the comments I wanted to make in reply.

KEATING: Thank you, Andrew. Other comments?

PRICE: I think, I can't remember who it was that said something about mass market new entrant costs are likely to be higher than the historic costs of the existing businesses such as AGL for example. We could speculate about that a lot, but markets, as we all know, as you all ascribe to, tell us a lot about how people behave and what their cost structures are, and I think it's instructive to observe that the number of retailers, small retailers, is going up, not down, and they are micro retailers, and generally you would expect their fixed costs to be spread over a fairly small customer base, but nonetheless, they do survive and they are growing quite rapidly in some markets. So I think what that tells us is that new entrants can actually be quite efficient and quite low cost operations, and it's certainly taking a share away from most of you guys, so that tells me either they're getting a lower margin, they're better at hedging or they've got lower costs, one of those things or three of them.

HAMILTON: Could I just respond to that. Yes, I think your assessment is correct, but the issue is that they're running billing systems out of the equivalent of an Excel spreadsheet. They have lower costs because in each place that they are, they don't offer the broadness of the products that mass market retailers do. So I'd certainly see almost two different curves, one for your micro retailer, but another for your mass market new entrant retailer, based on the suite of products, the b-to-b systems systems, their call centres, just the whole gamut of costs would be substantially higher and the fact that they - we're looking at really a business model whereby you get disgruntled ex executives setting up their own business. Not putting the finger on anyone. Running their businesses as hard as they can to the point at which they get critical mass, they can't sustain it and they'll be purchased by the larger operators.

PRICE: No, that's a fair point. So for clarity there are different classes of customers and there's a point at which you just can't run a system off a PC and some simple software, but there are a couple of businesses that I'm sure you're aware of and we are, where their systems are actually quite cheap, very efficient and highly scaleable, and they're not burdened with the costs of multiple legacy systems, like for example Country Energy and Integral and EA, for example, that do add to their cost structure. So there's sorts of swings and roundabouts that you need to take into account. So just because the businesses don't see their costs as being consistent with this, that doesn't necessarily mean that their costs reflect efficient costs. They often reflect a whole bunch of inefficiencies as well, not necessarily due to current management, but most certainly due to previous decisions and sometimes a decade or more ago. And part of that is the difficulties in rationalising tariffs and the complexities and costs of doing that, but remember what the terms of reference are, this is much more about sort of mass market new entrant. Again, not a business that really exists. Some of the more efficient larger businesses have been used as our benchmark and even then, my guess would be that we're sort of taking account of some inefficiencies. So I think it's finding a balance between the two.

HAMILTON: I think you're probably not - I agree in terms of swings and roundabouts, but in terms of your estimate of retail operating costs, we're not even at the level where you can take swings and roundabouts into account. We'd certainly be of the view that if Country Energy are operating at that level, that suggests a huge cost subsidy with their network business and we would be expecting consistent with every other retailer saying substantially higher figure for operating costs. So if we're having an argument in terms of efficient use of costs, that would be around the margins. We see that the number that you've come up with is not even within the ballpark, those sort of distinctions would really become of any significance really.

PRICE: I'll let Country Energy defend their own costs, but--

HAMILTON: 'Cross subsidy' might be the wrong term to use, but it suggests that there are benefits that can't be realised by other retailers, perhaps is better way of putting it..

KEATING: Any other comments? In that case, before we go to the next section, I'll just make a couple of observations. I don't think there' s a lot I can add to this. Let me just, in terms of the operating costs, of course it's quite obvious from Frontier's report that it's recommendations are below what the benchmarks were from others. That's obvious in the report. I wasn't aware about the point about Ofgem, that you shouldn't use 1997 and 1998 and should use something post 2000. I expect that Frontier will respond on that in their final report.

Frontier has already commented on the proposition of whether costs are rising or not, and that's not for the Tribunal at this stage to take a view on that. On customer acquisition costs, I have some sympathy with the views of PIAC, that it's slightly ironic that customers pay higher prices and particular customers pay higher prices who aren't actually offered a choice, because there is no choice. So I have some sympathy with that. On the other hand, I do think choice is worth something for those who do have a choice. I mean, most of us here, I suspect have wanted to change our bank or our telephone company at some point in time, perhaps less often our electricity retailer, but certainly the service I've had from banks or telephone companies has led me to change on occasions. I think that's actually something worth paying a bit for, just the right to seek redress in the most fundamental way.

I also imagine that in enticing customers or defending your present customers, that the retailers do provide information and that's of benefit to customers, whether or not they decide to leave or not, just in having that information and again at the end of the day you pay for it. So I think we are bound, I think, to make some allowance for customer acquisition costs. The issue is how much. The two points I've picked up in this regard are with the retailer and I look further forward to any further advice from Frontier on that point, because there was a sense I got today that the retailers don't think you're right there.

The other point was the discount rate. I take it when Country Energy suggests that it could be as high as 12.8 per cent, that's not a rate you'd apply to the whole business, because I don't know of any electricity authority that's regulated where the regulator is using a 12.8 per cent discount rate. Do you know any such rate, Jim?

COX: Not to my knowledge, certainly not in Australia.

KEATING: No, not in Australia and not overseas either, I don't think. Well, we're using real terms, so I take it these are real. So I don't think overseas is 12.8 per cent real either. So is there something in particular about customer acquisition costs which justifies a higher discount rate than you would apply to a business as a whole? You might want to take--

DELORENZO: The best really I can do with that is just to say that we will give you the full report.

KEATING: Yes, take that on notice, but if you wanted to pursue 12.8 per cent, it would need to be justified, let's put it that way. I think that's all I wanted to say in relation to this session and we might now move to retail margin. I think Frontier's going to lead us off again.

HARPHAM: We're going to talk about retail margin this time. I've got a few things to say and then I'll hand over to Stephen Gray from SFG. First, as an overview, the terms of reference which you've seen require consideration of a mass market new entrant retail margin. We've interpreted a mass market new entrant here in the same way that we did for the purposes of estimating retail costs. In terms of our approach, we've adopted three approaches to looking at the appropriate retail margin. First, a bottom up approach which I'll talk about briefly and then an expected returns approach which Stephen will talk about in some more detail, and again we've benchmarked the results of these against other regulatory decisions. The results of these are that we see convergence on the range for an appropriate retail margin between 4 per cent and 6 per cent.

Just briefly talking about the bottom up approach, there's two different ways of thinking about the bottom up approach which we looked at. The first was to assess a retailer's EBITDA essentially. We receive information from each of the standard retailers about their asset base as attributable to small retail customers and also the revenues attributable to those customers and on the basis of that worked out an EBITDA margin in a process that I think is fairly straightforward, but detailed in the report. This approach suggests that an appropriate retail margin would be in the range of 4.1 to 4.8 per cent and in Integral/NERA's submission to IPART's issues paper, which you all might have seen, it's available on IPART's website, they recommended a build up of different elements of the retail margin. This is not a direct representation of what they put in their report, because they included an allowance for customer acquisition costs in the retail margin rather than retail costs. Since we've put the customer acquisition costs in the retail costs, we've taken them out of this retail margin and represented what the implied range for the margin is on that basis, and that comes out to a range of between 2.8 to 5.4 per cent with a midpoint of 4.2 per cent.

Now I might hand over to Stephen Gray, who will talk a bit more about the expected returns approach.

GRAY: My name is Stephen Gray with the Strategic Finance Group. We've been working with Frontier on just this section on retail margins. Many of you will have seen the framework previously, so I'll sort of run through that fairly quickly and leave lots of time for questions.

I guess the first point is to note that this approach is one of three. What we tried to do is to come at this question with three quite different approaches and as Andrew mentioned, the three sort of corroborate one another and give us a higher degree of confidence that the output is reasonable. So within that context, what we've done with the expected returns approach is basically if we start with the sort of top left over here, if you tell me something about the - if you tell me what the retail margin is and you tell me information about the cost structure for the business and volume of sales, then from that I can give you a forecast of future cash flows for the business. If you then tell me something about the risk of those future cash flows, that necessarily implies a particular discount rate, which in standard practice I could use to find the present value of those future cash flows, and that tells me something about the overall value of the business, which in this case would likely be represented in terms of a value per customer.

There are any number of different cash flows and discount rates and value of business that could come out of this. So what we want to do is to ensure that there's two types of consistency. One is internal consistency, so it's got to be the case that the risk assumptions that we make when determining the discount rate are consistent with the risk of the cash flows that would be the outcome of the analysis. So we talk about that being internal consistency.

We also want a benchmark against other external benchmarks and we refer to that as external consistency. So for example if we did a theoretical modelling exercise and find that the value of the business implies a dollars per customer figure of 27,000 or something ridiculous, then we know that although there might be some theoretical internal consistency, it doesn't really match up with the real world. So what we want to impose on the modelling is those two forms of consistency. Within the model, everything has to be consistent with everything else in the model and then also at various points along the way, we have to have consistency with external benchmarks.

The risks that are involved are these, there's energy purchase price, so we're not exactly 100 per cent sure exactly what price will have to be paid to purchase energy. That's quantified earlier in the frontier modelling using the strike model. There's volume risk in terms of we're not sure exactly what quantity of sales will be made, and that has both systematic and non systematic components, and maybe we'll come back to that in a discussion later on. As raised earlier, there are non systematic components to volume risk which are weather related. And the way to think about whether a risk is systematic or not is to ask the question is this risk more likely to crystallise when the overall economy is up or down or whether the overall market is up or down. You're not likely to have hotter days or bushfires or storms on days when the stock market is up than when it's down, so they're unrelated.

That estimate of volume risk is non systematic, but there is a systematic component in that when the economy is doing well, GDP growth is high, the market is up, there's more demand for electricity and so that element is market related and therefore systematic and we've estimated that relationship and built that into the modelling.

Then the third form of risk is estimation risk, which is to say that there are various parameters throughout the whole analysis, not just this piece of it, but throughout the whole analysis there are various parameters and estimates that are made. It's the sort of thing that you really just can't put your hand on your heart and say that you've got the right number to two decimal places. We've looked at scenario analysis and quantified things in terms of economically reasonable ranges, rather than specific point estimates that don't account for any uncertainty in the estimates of the parameters.

Where that comes to is this, the EBITDA margins, you can see here in terms of percentage of sales, so that top line there is really the relevant one and for comparison purposes with the retailers' submissions is this range of 4.4 to 6.4 with a mid point a little above 5. We've also expressed that in terms of dollars, dollars per megawatt hour, dollars per customer and so on, but the relevant benchmark is really that first line there and that's really the outcome here, 4.4 to 6.4.

I'll finish this off, if you like. This is a very hard chart to explain. What we've got here is the culmination of all three approaches here. The sort of grey bars that are indicated a benchmark on the bottom axis there, they're previous regulatory determinations. Now, not all of these are directly comparable. We've put them into the same units as best we can in terms of an EBITDA margin, but they're not directly comparable, because not all of them include all of the risks that are included here. But that gives you some idea of where regulatory determinations are sitting.

The bottom up approach, basically taking the value of the business, what sort of return is required on that and therefore what cash flows and consequently margin is required from that, that's in the sort of black striped bars. You can see that going from a little above 4 to around about 5. And then the expected returns approach that I've just been talking about now is where the red hash lines are, which is - you can see broadly consistent with the other two approaches, although the expected returns approach is marginally higher.

So we haven't relied on one of these methods to the exclusion of the others. We have taken all of these things into consideration and looked at the range of - essentially the range of most overlap between those three approaches, where they sort of triangulate and corroborate one another and that's in the range in the thick black bars there, sort of the 4 to 6 per cent range. Thank you.

KEATING: Sean, thanks.

KELLY: Thank you, Michael. I did say to somebody earlier the worst thing you could do is trip on the stairs going down.

I'm going to be fairly brief on retail margins. It tends to be a fairly emotive topic when you come to pricing reviews. I think there's a few fundamental principles that we should consider before we actually talk about the quantum and I think it goes to some of the discussions that we've heard previously on some of the other things. At the end of the day, the margin that's set in terms of whether you actually achieve that margin is only achieved if the benchmark costs that are set are actually reflective of the costs that you operate in your business. So if your wholesale costs or your operating costs benchmarks are below your actual wholesale costs or operating costs, then you won't achieve the benchmark margin and that's, I suppose, fairly straightforward, but historically in a number of reviews in other states it has caused some problems.

I think it's critical that, as we've discussed previously, that we understand where the risks are actually captured, whether they're captured in the actual benchmark costs or the margins, and I'm not going to go into an expansion on the discussion around systematic and non systematic risks in regards to the wholesale, but it's obviously an area that has been raised as to whether those risks have been appropriately addressed at the moment, either in the wholesale costs or in the margin.

It's fair to say that if you look at the graph that Stephen put up and he talks about a range of margins, it's interesting that the two markets that had the higher benchmark margins that have been published are the two markets that are commonly talked about, being the competitive markets in Australia. There's a recognition that if you can establish the benchmark margin or the margin that exists in the market place at the appropriate level, then you start to achieve one of the objectives of the Tribunal, which is to remove the reliance on regulated prices and start to generate a position where you actually have prices set by the market and as discussed earlier, that's a fairly critical long term ambition, because ultimately if you've got market based prices, then you'll get the right price signals for the future investment in generation capacity.

In terms of the specific quantum, I think from an AGL perspective that a margin in the range of 5 to 10 per cent is far more consistent with what we would expect and see, particularly in those jurisdictions where you do have effective competition. I think there's a consideration that looking at benchmarks tends not to address - and this is something that I encourage the Tribunal to consider is what is the end state within a price path. The level of competition ultimately is derived by whatever the margins are that are being earned at any particular time, and whilst in many of the price paths you have an average benchmark margin that's talked about, historically some of those margins are different year on year and potentially are higher in the back end of the price paths, which is actually generated competition. That's all I've got to say, thanks.

KEATING: Thanks, Sean. PIAC?

FREEMAN: Thank you, Michael. As I was sitting here listening to retailers presenting their views on retail margin and I was thinking back to a meeting I was at last year in Victoria and a group of consumer advocates from every jurisdiction was represented, had got together and we had a presentation by a retailer who came in, wanted to teach us a few things about how the retail market operated. He put up a graph - I can talk about it because he's not in the room, that's fine - he put up a graph somewhat similar to what we've been talking about today, which was looking at benchmarks of retail margins across jurisdictions, and he had these very high retail margins in all these very competitive jurisdictions and he came to New South Wales and he said, look, isn't this terrible, you've got this 2 per cent margin and it's terrible, you're not seeing anywhere near the competition that you're getting in the other jurisdictions.

Yes, okay, the next slide came up and it had the prices and it had prices in these very competitive jurisdictions and then it had prices in New South Wales, and he said, look, isn't this terrible, your price is so low. I think it speaks volumes to the point we're talking about today, which is the more that we push up margins, I think we need to acknowledge that equally we're going to be pushing up prices. Like I was referring to earlier, realistically we need to see this for what it is, which is headroom pricing, and it starts to create some of that circularity which was talked about earlier today, the irony that Michael was talking about where we're paying higher prices to enjoy more competition. Certainly to some degree that's warranted, but at the same time, I guess we need to balance what exactly we're talking about here, which is a market for an essential service, a market for energy.

So I guess predictably our view is that we'd like to see retail margins kept what we'd see at a more reasonable level and keep as much pressure as we can off households that are going to be relying on a regulated tariff for some time yet. Certainly whatever is delivered in this determination is going to see some increase in competition, but I guess PIAC would argue that there's degrees of competition and that slowly allowing more competition in isn't necessarily a bad thing, rather than looking for the types of shocks that we saw in South Australia, price shocks, that is.

I also just wanted to talk very briefly about retail price regulation, which is the reality in which we're operating. There is a significant number of customer base who do rely on the regulated retail price and while customers are increasingly choosing to move away from that. I think there is still an obligation to protect the customers, who either aren't able to access it or still learning about the market and looking for those opportunities.

PIAC sees retail price regulation as a price to beat. It's based on efficient costs. I think the important point there is for customers who for whatever reason need to remain with a regulated retail price, they're enjoying a price that isn't set above efficient levels, and I think there's some risk in this price review that we're going to see above efficient levels for those customers.

I think it's also important to keep in mind that as well as customers who aren't able to elect to move on to a negotiated tariff, there's a lot of customers who rely on exempt suppliers for their supply of electricity. There's approximately 40,000 residents of residential parks in New South Wales and their electricity prices are directly benchmarked against the regulated retail price. So I think we need to be a little bit cautious in the flippant view that customers can negotiate away any price increases. Inevitably there's going to be customers who rely on a regulated retail tariff in this price review.

I might just leave it at that and I guess again we'll provide more information in our submission about retail margins, but again certainly whatever, if it is taken to keep costs down, is going to benefit a large portion of vulnerable customers.

KEATING: Integral?

WALDMAN: Karen Waldman, Integral Energy. Integral has two main concerns over the aspects of Frontier's and SPG's approach to assessing the retail margin. One is how the energy purchase cost risks are captured and the other is the methodology associated with the expected returns. If I go to the first, it's just not obvious to us how Frontier has captured the energy purchase risks in their framework. We're not seeing the linkage between energy costs and the margin. I think with the different risks inherent in either the long run marginal cost or the elbow point or the conservative energy cost allowances don't appear to be reflected in different margins.

Based on our expected load, we would see a dollar difference in energy costs results in a shortfall of approximately $14 million over the three year period. Our submission highlighted the fact that it doesn't matter whether it's in the energy purchase cost allowance or it's in the margin, we just need to ensure that this risk is catered for.

If I move to the expected returns, this, I think as was presented earlier, is pretty complex. We have two main issues with this. The first is that it seems to be based on holding cash flows rather than assets constant, and it appears to lead to a result that is counter intuitive for regulated business. If the cash flow is held constant, the model implies a lower margin for a higher risk. Whereas a higher WACC should not result in a lower margin. So that's one of our concerns.

The second relates to the fact that we've seen a retail margin recommended of somewhere between 4 to 6 per cent and that this gives rise to a value per customer of approximately $600 as stated in the report, and that's not hugely inconsistent with market evidence. But Frontier suggests that only $200 of the capital is required to be invested per customer. It seems to us that this approach results in Frontier's customer valuations being three times the assumed level of capital invested, which doesn't appear reasonable and seems to be ignoring $400 of capital per customer. So that's another area of our concern.

While this has been spoken about by others in the operating costs section, we would like to add that although there have been submissions about estimates of churn included by the retailers, I acknowledge that, those assumptions would need to be revised if competition were to increase as an outcome of this review, because clearly, as customer churn would increase over a shorter period given increase in competition.

I would just like to I suppose reiterate that these customer acquisition assumptions we've dealt with the in the margin and therefore arrived at a point of around 10 per cent, I think in our midpoint. Frontier has dealt with it in the operating costs. Again, we don't mind where it's included, as long as the corresponding increases are included.

In summary, as we highlighted earlier under the energy purchase cost discussion, there is a risk to Integral Energy if IPART set the energy purchase cost allowance too low and that's reflected in a shortfall in Integral's returns. The margin set by IPART will need to adequately compensate Integral Energy for this risk. Getting it right now is critical and so these complex decisions, I guess, by IPART about these issues are going to affect the future viability of the retail businesses, the level of competition in New South Wales, and the level of new entrant generation in New South Wales. Thank you.

KEATING: Thank you, Karen.

ADAMS: John Adams, Group General Manager Retail from Country Energy. Just while we're setting up, I should take the opportunity just to respond to the assertion from Graeme, I think it was, about the cross subsidy, that it must be a cross subsidy. I can say to you that absolutely there is no cross subsidy that I'm aware of. It's a historic fact that Country Energy has benchmarked well, not only in retail operating costs, but also in network costs, for a number of years. I think it probably reflects the fact that it is quite well established and it's fully integrated and quite diverse business. But the other key thing of course is that the accounts are audited accounts and submitted regularly and again the pattern has been followed over the years. So let me just reassure you that there is no cross subsidy in those costs. I did, however, make the point that they are increasing and I think that also reflects the changing nature of the market, the increased competition that we're seeing.

HAMILTON: I should apologise, I shouldn't have used the word cross subsidy and I did correct myself. I should have said that there are efficiencies that other businesses can’t achieve.

ADAMS: I appreciate you saying that, thank you.

Turning to retail margin, our basic position is that for the term of this review, the retail margin that's been recommended is considered appropriate for the current retailers, provided that the risks involved with purchasing energy in the absence of ETEF are adequately captured in the energy costs. And I think now a number of people have said it, there's really quite a little triangle here that I empathise with the Tribunal that you will be grappling with, but I think in terms of a transition away from ETEF, the level of margin that's been recommended is not too bad for a transition period. We just comment again that if the energy costs are inadequate, the recommended level of retail margin of itself is unlikely to provide sufficient incentive for a new entrant retailer to enter the market.

The final point is that this linkage, not only between margin and energy costs, also links back to the customer churn assumptions. So with a change in margin and with any adjustment or sensitivity around the expected life of a customer, we again concede an interesting balance that needs to be addressed there by the Tribunal.

In summary again, a balance is required and the type of range discussed, we believe is a good starting point.

KEATING: Thanks very much for that. Energy Australia?

MOODY: Phil Moody from Energy Australia again. I must admit when I first saw the methodology that Stephen was using, I was quite excited. I thought that particularly to the extent it was looking at volatility in cash flows, I was expecting something quite extraordinary, in fact that we'd have to even tone it down a little. I think the issue to my mind is that it's not so much what's in this margin, but actually what's been excluded, and that's obviously a theme with the presentations here this afternoon. There is, as Stephen mentioned, a number of risks which they have addressed, but I note on page 42 of their report, most of them are dismissed as non systematic and in fact only a very small proportion of them actually make it into this margin.

In relation to the risks that this margin has covered, I have no issue at all. I think it probably does quite an appropriate job. Our contention is what happens to all the others that aren't covered. This won't take long, but here's a list of them. The first two that I'll talk about in some ways are unique to a situation we're going to face in this determination, which I have spoken about earlier. It's the fact that we are now going to buy what amounts - between the three standard retailers - what amounts to about 20 to 25 per cent of the New South Wales market in hedges and that raises the issue of liquidity risk. The words I've put up there are probably not entirely correct. Liquidity risk is generally about your ability to get in and out of positions in the market and it's a question of volume and how much you need to move. The specific example we have here is that we're going to be buying a substantial volume, much more than we would normally buy at any given point in time. The way that we normally manage this in our normal business operations for the rest of our portfolio is we buy smaller licks of energy incrementally. So that is a distinct difference that we'll have here.

Contract price movement, which we've talked about previously, again the reason it's in issue here is because we're not buying and selling at the same time, we're going to set a price for the next three years and then we'll have to go out and buy against that over time. So again that's a risk that we would normally have a process for dealing with, but we can't diversify it in this case.

Counter party credit risk, this is essentially the risk - it's something that only arises if your contracts are in the money, funnily enough, but you don't have it if your contracts are out of the money. To the extent you have contracts in the money, it's the ability of your counter parties to pay and we've certainly seen examples where counter parties have become bankrupt and in fact Enron is obviously a popular example, and that's still being wound up.

It's just worth mentioning that the risks I'm mentioning here are not captured to my knowledge in the costings here. I should make the point that bad debts are captured in the opex cost allowance, but that's for bad debts with customers, as distinct to what amounts to bad debts with wholesale counter parties.

Regulatory risk, these are things such as changes to the level of VoLL, which do happen from time to time and have a substantial impact on the market. Region boundary reviews, we've never had one change yet, but there is currently a draft out there proposing changes to the Snowy region boundary. Also changes to green legislation and such things. So there is quite a lot of exposure in the regulatory space.

Demand risk, this is essentially just the fact there was a lot of talk about movements in the level of energy required as a function of GDP. One of the issues unique to our market is that you can't store electricity and the outturn price is really driven by the instances of VoLL and half hour capacity movements, which is why this is so important. So the instances of VoLL in any given year, which may typically be in the order of .1 and .2 per cent of the outcomes in a year, contribute in the order of 20 to 30 per cent to the final spot price that materialises. So that concept that these handful of half hour outcomes, which predominantly are driven by whether or not you've had a hot summer or a mild summer, have a considerable impact on our exposure and our energy purchase costs and certainly well above the margin allowances that have been envisaged here so far.

Forecasting risk has been mentioned previously as well. This sort of spans probably a number of these other areas as well where it is just your ability to predict what your customers are going to do, as well as how many you're going to have. So just another aspect of the risks that we have to manage. And again, hedge mismatch, that's essentially the issue that we can't buy the product that we're going to sell, and it's a bit like agreeing to sell an apple, but you can only buy fruit salad and then you try to put all the bits together, but they never quite look the same.

In short, that's all of those red risks in my opinion and in my reading of the reports. They certainly aren't captured in the margin. Some of them are talked about in relation to - certainly things like the estimation risks are talked about in relation to the energy costs, but there's no clear direction in my mind that they're being factored into the resulting energy price, so like everyone else, I don't mind where they go, as long as they go somewhere.

If I could just mention a couple of things that have come up. In relation to the current levels of churn that we have in New South Wales, in my opinion, I think there' s a misconception that they reflect the margin that we have there now. I would argue that there's in fact no room in terms of the current tariff today and where the costs are, but rather that the level of competition that we're seeing in the market today is predicated on the players' forward views of where the tariff was going, and I think it would be fairly safe to say that if this next tariff doesn't move anywhere in real terms, you'll see that pretty well dry up, because people are taking that view over the next three years.

That's why I think in our submission we've made the point that we think New South Wales is well primed, there's players there that already actively have systems and processes in place to acquire customers, but they are, I suppose, strategically holding back a little, effectively hedging their risks that tariffs don't go up or whatever. The other things to consider are - I hope I'm not going too far out of school here, but there are much more attractive margins, for example in the gas area, so dual fuel customers, for example, are more attractive. So they'll be customers that people will try to win.

I'd just like to make a comment about the concept of headroom pricing. As I said earlier, we certainly subscribe to the view that you shouldn't increase prices for the purposes of encouraging competition alone. I think there's probably perhaps a misunderstanding that when we're talking about margin, we're talking about profit margin. What we're talking about here is a recognition of the risk essentially, in my view, of the energy cost, and with the numbers we talked about earlier, we're talking, if you add all these up, they're sort of plus or minus 10, probably 15 per cent, well above - which could send any of us broke. We'd be happy if they were all a lot more stable. Unfortunately they're not. That just about wraps it up.

KEATING: Thank you. It's now open for comment, questions.

GRAY: We had a telephone conference call with the three incumbent retailers on Tuesday, I think it was, and we indicated that - a number of questions were raised, points of clarification and so on. We indicated that we'd have a response document today for that and we do have that completed, and it's 10 or 12 pages that basically address the points that were raised in that phone conference and earlier emails that have more detail and clarification of conceptually what's going on. That will be with the Tribunal this afternoon and sent around after that.

But what I'll do here is maybe just talk about the points that were raised along the way and our view of how they would be handled and where they fit into the overall process. The first one, the AGL point that there's no guarantee that the benchmark margin will actually be received, that's something that was raised in the conference call, so we've got some response to that in this additional document and we'll be beefing up in the final report that section to make that point very clear and what the boundaries around that are to the Tribunal, and I'm sure they're already well aware of that.

I'll come back to Integral in a moment, because that's the most complex, hoping that people have left by the time I get to that. No, I think I've got a good answer to that. The Country Energy, the appropriate retail margin, so long as energy purchase risks are handled adequately, that is sort of in common with the EA view that this swag of risks need to be handled somewhere. So here is the framework, the way I think they need to be handled and where they fit in. The retail margin that we've got here is sort of the standard regulatory approach and standard corporate finance practice really is to allow what is in this case a retail margin or in other places a return on capital that's compensation for the systematic risk that's borne by investors. That swag of risks that you have there are not systematic and so don't get included in the retail margin, and that's not at all to say that they're irrelevant and don't get included anywhere. I'll just come back to where they fit in.

What needs to be compensated in terms of the retail margin or return on capital is systematic risk, market related risk, what are those risks that fire up when the market is down and not when the market is up or vice versa. So that's what we've included in the retail margin and we'll be very clear about what's in and what's out in our revised final report for the Tribunal. So they're very clear on those things as well.

Those non systematic or diversifiable risks, if I can just clear up one point. When we took this whole corporate finance framework in terms of the diversifiability - which is a new word that I learned this morning - the diversifiability is in relation to the ultimate investor or shareholder and not the business itself. So I know that your business can't diversify in a credit default risk or whatever, but the ultimate investor, if you think about a shareholder in that business, that shareholder can own shares in 10 different businesses across different sections of the economy, each one of which is a very pure play business with a number of risks that it can't diversify, but that diversification is done at the shareholder level by holding a diversified portfolio or mutual fund.

So it's not right to say that you need compensation because your business is unable to diversify the risk, just to clear that up, but again this is not to say that all of these risks that you've mentioned are irrelevant, and they’re certainly not - in the frame that needs to be taken into account is in terms of your yellow distribution that you had earlier this morning where you put that together and you recognised that the energy purchase costs, those elbow points have a mean and a standard deviation. There's some chance that the actual outturn energy purchase costs is going to be higher than that mean and some chance that it's going to be lower than that mean, and the reasons that it might be higher and the reasons that it might be lower are related to the sorts of risk factors that you've got here. If you could immunise yourself against all of those red risk factors, that standard deviation shrinks basically to nil, and you'd be a government bond instead of an energy retailer. I'm sure it would be an easier job, but much less fun. So that's where that comes in.

Now, what the Tribunal's job is going to be is to determine in terms of reference as to whether they want to choose that 50th percentile or something above, and there's going to be arguments either way. The higher above there, the more chance there is - you talk about a probability of exceedance or something. If they go above that midpoint, the 75th or the 90th percentile or whatever it is, that's a much higher probability that you're going to be charging prices that cover all of your costs. The counter point is that other people call that head room and so it would be the Tribunal's job to balance where to draw the line on those things. But those diversifiable and non systematic risk factors are basically captured in that standard deviation type number. That's why there's a standard deviation there and why the actual outcome energy costs might be higher or lower than that mean point, if that clears that up.

Everyone is still here, so I'll go back to the Integral Energy thing. I think we're a little bit at cross purposes here, and we need to do a better job of explaining exactly what's going on in the model, because there is a view that what's going on the modelling is different from what's actually going on in the modelling.

I think you mentioned, Karen, that if we hold the value of the business constant, that a higher WACC results in a lower margin. That's just not the case. If you're holding the value of the business constant, as you would in a network regulation case, hold the value of the business constant, if you increase WACC, then the margin is going to go up. And in our note you'll see we've actually put some numbers as to how much to give an idea of the sensitivities to that, and we've explained why that is the case in our modelling.

Where I think some confusion has arisen is that we might be a little bit at cross purposes between what's the true cost of funds and the regulated return. If I can use the analogy of a network regulation case, it's not the case that in a network regulation determination that the Tribunal determines your cost of capital, the Tribunal determines what price you can charge. It's the capital markets that determine your cost of capital. So what the Tribunal is going to do to figure out what's a fair price, they'll do some estimates and talk about WACC and so on, but ultimately what the Tribunal is determining is what price you can charge. The true cost of funds to the business is determined by capital markets.

Once the Tribunal has done their job and they've determined how much you can charge, if circumstances change and your cost of capital rises - so suppose interest rates go up next week unexpectedly, the market is not expecting it, suppose it goes up, then what will happen is that you'll see the share markets sell of, because that's new information, higher cost of funds, higher cost of capital, and share prices will fall. And that feature is built into our modelling. So for a given set of cash flows, if the true cost of funds, not prices determined by a Tribunal that has an intermediate step that has a heading in the report called WACC. If the true cost of funds goes up, then asset prices fall and that's built into our model. And I think that's what's confusing people. They're thinking that in a network determination case, if we can convince the Tribunal that our WACC is higher, then aren't we supposed to be better off. And the answer is yes, but what you've not done is increase your cost of capital, you've convinced the Tribunal to let you charge more, and those two things are quite different. We've tried to make very clear in this note and in the revised report what the difference is there. I'm not sure if this has helped at all, but we've got a paper that we'll distribute it and a revised report.

MARTINSON: Mike Martinson from Integral. Thanks for that explanation and certainly we appreciate you guys pulling together that discussion paper following our talk on Tuesday. I think where you've highlighted is probably that we have a better understanding now of the way that your model actually works, and I think the key aspect - and we'll certainly spell this out in our submission and our advisers are certainly preparing a response on it - is that approach of saying, in a regulatory context, is it reasonable to say fix your cash flows and exactly what you're describing to say we would expect that we would have a certain level of assets in our business and with a higher risk, we would expect a higher return in a regulatory setting. What I'm hearing you say is well, maybe that's not reasonable and let's just come up with a stream of cash flows, and then if your risk is higher, you'll either reduce your capital or you will lower the margin that's allowed on it. And that's the issue that we'll spell out further in our submission, but obviously we're keen to see your paper on that.

GRAY: We do both, remember. We do the bottom up approach, which is fairly similar to a standard regulatory approach where we say here's a cost, here's an asset base, to use a net worth analogy, and then apply a required return to that to determine what cash flows would be required and therefore what margin. So that's done, that's our bottom up approach.

ORM: Excuse me, I didn't see a discussion about the--

KEATING: Hold on, I'll just get the mike.

ORM: ..(not transcribable)..--

KEATING: Sorry, can you just wait. I'll get the microphone. Otherwise it's not going in the transcript.

ORM: My name is Simon Orm, I'm helping Integral with some advice, actually not on this specific issue, I hasten to add. I just wanted to draw reference to the comparison with network regulation, because my understanding is of course that with the network regulation, a great deal of discussion is about the initial capital base; what is the amount of capital that we are discussing here. This is the problem I think we're having here is of course the more risk you have, if you go along that risk return frontier we discussed this morning, you have to allocate more capital. That's in the Treasury risk management guidelines. And of course you then need to get a return on that capital. So this, I think, is the bit that's missing from the model, as far as I can tell.

Just while I've go the microphone, in the margin I think I've got the range in the margin was in dollars per megawatt hours between $7.48 and $11.11 per megawatt hour. We saw this morning on the risk return frontier, I think larger variations across that return frontier and I just find it hard to link up the movement along that risk return frontier for the wholesale energy price with the variance in the margin. It would be great if you could tell us which is the elbow point between that mid point, high point and low point, which is the elbow point and which is the conservative point on that risk return frontier.

GRAY: We can do that, the Frontier guys can do that. I guess there's a couple of things outstanding. One is we've done that bottom up network regulation style exercise, and to be frank, the range that we come up with is, in terms of margin, is higher than what was asked for basically in the submission on a like for like basis. So that's using that approach. The expected returns approach doesn't necessarily hold the enterprise value fixed, and why is that the case? Well, why might a retail business be trying to talk up and argue for a higher margin? You obviously have an incentive to have the margin higher because you think that's going to increase shareholder value, which says to me that you can't possibly tell me with 100 per cent certainty what the value of the enterprise is per customer until you know what the margin is.

It's this simple, if margins go up, the value of your business is higher. If margins go down, the value of your business is lower. In a network regulation case, that doesn't happen. What the regulator does is tweak things so that the value of the business stays constant. But this is a mass market new entrant coming into an unregulated business where the value of that business is going to go up and down. On a listed firm, the stock price is going to go up and down as margins go up and down and as costs of capital go up and down, and that's what's being built into the model.

MARTINSON: If I can just add, I mean, I guess one of the areas that obviously we're trying to work our way through before our submission next week is I guess the concept of knowing that there are particular assets in the business, knowing that in the draft report there's customer acquisition costs of $200 per customer, but yet there's a value per customer of around $600. I guess we're really trying to look at partly in coming up with those numbers, we're trying to look and say, well, to get that value does that mean you're implicitly reducing the capital in our business to give us the $600, and that in this setting is what we're trying to look at and obviously we will spell it out in greater detail in our submission, but the more information we can get on your methodology, it helps us in that sense, because if it's giving a false sense that $600 based on the level of capital in our business is not the answer that would provide some concern for--

GRAY: No, I understand that, and we'll provide more information to address that particular point as well and we've got this document. I think the discussion has reached a point where the most efficient way ahead - we're happy to respond and continue our discussion.

MARTINSON: I just want to make one final point, which of course in the value of a retail business, one of the key issues is actually the value of the energy portfolio and its riskiness. So that goes to some of the prices that we've seen in the market as an assessment of the riskiness of the energy trading portfolio. The value of the energy trading portfolio, the amount of risk it has in it and the value of the whole retail business are very closely linked.

GRAY: I don't disagree with that. Is there an implication that we've missed that? I don't think we have. That point really has little to go with the retail margin and more to do with where you would draw the line on the distribution of energy purchase costs, if that makes sense. So yes, there's a whole range of factors and risk factors that the Tribunal will need to consider in determining which point within yellow distribution they would select as being consistent with the terms of reference.

KEATING: Thanks very much. Other comments, questions? I might bring things to a close now. Can I just say in relation to our fourth session, I did find your explanation quite helpful, Stephen, myself. On this quite critical issue of what are the risks that retailers are facing, particularly in respect of energy purchase and I suppose the best list of them is the list that Phil Moody had in his presentation. I think we understand that Frontier proposes to handle these risks relating to energy purchase in the context of energy purchase and not in the margin, not in the retail margin. On that basis I was heartened by the comment particularly from Country Energy that the retail margin looks about - well, it's in the right ballpark. That's heartening and I don't think Energy Australia really disagree with that either, as long as the energy purchasing risks are properly handled.

So it will be important that that's further considered, I think, by Frontier, and can I say in that context also, Stephen, I think you referred to the notion of the standard deviations and whether you moved to further up from a 50 per cent probability to a 65 per cent probability and so on. I think any further reflections that Frontier have on that, the Tribunal will find helpful in due course, but I think the clarification we had in the last 10 minutes of so has been quite helpful.

Can I also say in relation to the last session that we didn't discuss the merits at all of the expected returns approach to the bottom up approach versus the benchmarking when it came to retail margin. So when you make your submissions, I'd be interested if you had any reflections on that, particularly in the context of the expected returns versus the bottom up, where I think - we haven't got the graph in front of us, but essentially while there was some overlap between the top of the bottom up and the bottom of the expected returns, the essential message was that the expected returns were giving a higher answer than the bottom up. It would be interesting, I mean, I guess I could foreshadow what you're going to argue for, but perhaps the reasons why you might prefer one as against the other would be helpful.

The final observation I wanted to make was on this question of head room, and I think it's possibly an unfortunate term. We're being urged to take a conservative view in terms of the risks and so on and that in turn gets reflected at the end of the day in a higher price. An objective that's been put on the line here is that we develop a more competitive market and so on, and I suppose on one sense if at the end of the determination the actual market price was generally below the regulated price, some people might regard that as a sign of considerable success, they'd say, well, that proves there's plenty of competition, et cetera, if that was the eventual outcome. I could have a certain degree of sympathy for that myself. I haven't spent my life as a regulator. In fact, I copped quite a lot of ribbing from my friends when I took a job as a regulator. Ideally we wouldn't want too big a gap between the regulated price and the market price, it wouldn't reflect very well on us, I don't think, and more seriously, there will be some people who are on the regulated price because they have no alternative. So I just think we need to bear that in mind, that the ideal outcome would be the two pretty close together, I suspect, with plenty of market competition.

With that, I'd like now to just bring things to a close. A transcript of today's proceedings will be available on the Tribunal's website in the next week or so. Unfortunately some comments from the floor might be difficult to capture in this morning's session. Please remember that the submissions and the draft reports are due on Friday week, tomorrow week. All submissions, comments and questions should be made directly to IPART rather than to Frontier. I don't want to be absolutely strict about this, but we do need to be in the loop all the way and the easiest way to do that is if conversations are through us. Anyone with questions regarding their submission, you can contact Anna Brakey, who I'm sure is well known to you all from the secretariat.

In closing, I'd like to thank you all once again for attending and indeed for the work that you've put into this hearing. Thanks very much.

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