**RESUMED** **[1.30 pm]**

COMMISSIONER: Let’s reconvene and I welcome Prof Graham Nathan and Dr Robert Dickinson. Mr Jacobi.

MR JACOBI: Prof Nathan is the founding director of the University of Adelaide’s Centre for Energy Technology and is a recipient of a Discovery Outstanding Researcher Award from the Australian Research Council. He’s a specialist in thermal fluid science and technology. He works with energy technologies, spanning the combustion and gasification of fossil and biofuels, concentrating solar thermal power and fuels, geothermal energy, wind power, energy storage and in hybrid technologies. He has worked closely with industry throughout his career and he holds an industrial electorship for the last 13 years, as well as many consultancies. He has made a submission to the Commission which is published on its website, in conjunction with two other academics from the University of Adelaide.

With him is Dr Robert Dickinson. Robert has a PhD in systems design engineering from Canada's University of Waterloo. He developed a novel method for modelling large scale probabilistic physical systems and on his relocation in 2005 to Adelaide he has an undertaken an ongoing research collaboration with the University of Adelaide, Centre for Energy Technology and he's a member of several engineering and energy professional associations and represents Australia in an emerging international inter-agency task on power hydrogen. He has also made a separate submission to the Commission which will also be addressed in today's public session.

COMMISSIONER: Thank you. If I might start with you, professor. In your submission you talk about new power generation needing to meet Co2 emissions in firm supply, in South Australia you talk about the importance of flexibility in the challenge. Could you just talk broadly to start with about the characteristics of new power generation that you think are important for our future?

PROF NATHAN: Power generation systems are required in general to have increasing flexibility because there is increased variability in the supply end. I guess stored hydro is the exception, but apart from stored hydro all the others rely on intermittent and variable supplies. Geothermal is the other exception, but neither of those are particularly relevant in South Australia in the short term, the short to medium term, so then wind and solar PV are the two main supply sources and as there penetration increases because the supply varies with the available resource hence there's increased fluctuation on the supply side and likewise we still retain significant variability on the demand side, although there are many suites of technologies being evolved to accommodate this including downstream supply. Nevertheless at the supply end it's increasingly desirable to have a significant fraction that can maintain the capacity for firm supply which allows a component to be maintained irrespective of the variability in the upstream supply to maintain stability in the network.

MR JACOBI: Professor, do you have a view about the amount of firm supply you're required to have in any system? Is there a way of thinking about what you might understand to be the total need for firm supply within a system as a characteristic of the generators that otherwise exist in that system?

PROF NATHAN: Obviously this is a contextual, specific question, so within one part of the – different parts of the world will have different combinations of generators of different age and different capability, but by and large the types of technology which are most flexible are those supplied by natural gas fuel and natural gas, particularly with a gas turbine, has got the shortest start up and shut down time and pretty much all systems have got a component of natural gas turbines. The open cycle have got the shortest response, the combined cycle have got a slower response, but they also use a steam turbine which has got a higher thermal mass, so it's higher efficiency, but lower start up and shut down in this mix, so then below that things like plants that use solid fuel, such as coal, have got a very poor start up and shut down because it takes a lot of inertia in starting up the pulverised fuel system, but natural gas is the one that is a critical part of most current and emerging systems for maintaining the shortest response to the system and I guess one of the points of my submission is that whilst current systems consider the natural gas to be pretty much in isolation one of the emerging technologies is to hybridise this, so now you can have a system which contains a renewable component as well as the flexibility of the solar thermal. The most flexible systems are not yet commercially available, but these are emerging and it's still for the foreseeable future. The firm supply component that's most likely to be available is one which is based on combustion, which in the short term would probably still be natural gas, but in the longer term fuels can also be made from renewable resources which could be produced either renewably from hydrogen or the like or could be generated from solar thermal and other sources. There's a suite of potentially new technologies, but because of the high energy density and the short response time of gaseous fuels it's likely that these will be an important part for the foreseeable future of maintaining the firm supply, but this can be integrated with some renewable sources such as solar thermal to provide a good balance between rapid response and lower solar share – lower carbon footprint.

MR JACOBI: It's that last aspect I want to pick up. Your submission talks about, this is before one thinks about using future fuels in those plants, the hybrid technology having relatively low Co2 emissions. I'm just wondering whether you might be able to contrast where you think such a system sits perhaps as against a standard gas - - -

PROF NATHAN: Gas turbine?

MR JACOBI: Yes, a gas turbine in terms of its emissions intensity.

PROF NATHAN: That's right, so gas turbines have the advantage of a short response time. Typically the modern ones can be about 40 per cent efficient, the open cycle. The state of the art combine cycle is around about 60 per cent efficient, so the rapid response is about 40 per cent efficient. Solar thermal plants currently are a bit less efficient than that, they're in the low 30s in the percentage, however when we look – one of the disadvantages of natural gas, gas turbines in general is that they're very difficult to capture the Co2 emissions, so unlike a coal fired power station, which burns in pretty much stoic metric air therefore the amount of nitrogen in the exhaust products is fairly high, but you end up with around about 10 per cent Co2 in the exhaust, so the cost of carbon capture is all based around a coal fired plant.

On the other hand if you look at natural gas fired plant from a gas turbine then they're diluted very greatly to avoid the combustion products overheating the turbine, which means that the exhaust is highly dilute hence it costs a lot more both in energy, which is a parasitic Co2 loss, and in energy and cost which means that by the time you look at carbon capture and storage even a combined cycle power station, which is the most efficient at the moment, only becomes comparable with coal when you compare one with carbon capture. On the other hand if you look at a plant which has got Co2 integrated with a solar thermal plant then because you're burning less fuel already because you're substituting it it ends up coming out pretty comparable and these technologies are advancing rapidly, so we think it's not going to be long before it's going to be quite a bit more efficient to – and lower net carbon and lower net cost compared with a carbon capture plant from, say, a peaking plant and also will retain the flexibility.

MR JACOBI: I think your submission then forecasts the idea that such combustion techniques which when paired with solar thermal can use fuels that are not currently used in these plants. Is there a basis for thinking that emissions will be further reduced in those circumstances?

PROF NATHAN: That is right. So for example, it is possible to upgrade natural gas by using thermal heat, for example from renewable energy such as concentrating solar to converted in to sim gas which then basically puts a component of solar energy in to the fuel which therefore means it has a lower net carbon footprint. This is one of the technologies which is under – it is fairly well advanced in its development although not yet commercial. For example CSIRO have done some fairly large-scale pilot scale trials on this kind of technology. Then in the future it is also possible to upgrade biomass in to sim gas with, for example, solar thermal heat. So in addition of course to even – from electricity such as wind, PV, any of these can also be used hypothetically to generate hydrogen. So there are a number of technologies under development which in the longer term will provide a gaseous fuel that could be used to provide the short-term transitional fuel with a low carbon content in to the future to maintain the flexibility of operation together with an increasingly lower carbon footprint. So you would expect in the short term, simply supplementing some of the fuel with a solar component whilst still using natural gas would retain the flexibility and give a lower net carbon footprint and then in the longer term, as other technologies are developed, the fuel itself can be made increasingly with a renewable fraction and this will be expected to continue as these technologies evolve.

MR JACOBI: Your submission also speaks – then we go on to deal with the storage aspects of your submission. It speaks about, again, this hybrid combination producing a low cost means of storing renewable energy and I am just interested to understand what is the precise technology, that is in terms of its commercial exploitation which demonstrates this low cost storage option?

PROF NATHAN: So what I am referring to there is not so much necessarily that the storage would be lower cost, the particular point is that the amount of storage can be optimised to give the lowest cost. So the point is that – so thermal energy storage is now commercially available in things like solar thermal plants but it is also being used in some coal-fired power stations for example, where you can add some thermal storage in to the system to give some output. So thermal – it is much cheaper to store heat than electricity and more efficient to do so. If you store the - - -

MR JACOBI: Is that expected to remain the case?

PROF NATHAN: For the foreseeable future, yes. I mean for quite a long time because basically it is quite cheap to store heat, batteries are still much, much more expensive to produce although the costs are coming down. So what you are doing is you are storing the heat before it goes through the power generator. So therefore you still lose the efficiency of the power generation but compared to generating it and with the battery you are generating it and then you are converting it from one form of energy to another. So they are typically something like 60 per cent efficient but you can store the heat before you put it through the generator at greater than 95 per cent efficiency. So there is going to be long-term benefits in this – and it is also cheap because you are just storing heat. So the costs of this are expected to be cheaper for a long time and in fact this is one of the main drivers in the IEA's road map as to why they think solar thermal, even though currently PV is looking like it may well be – even if it is lower cost at the first point of production, when you include storage they think thermal energy is going to remain as a key driver for why thermal energy will be continued to invest in for quite a long time because its advantage in low storage.

The point is this though, that if you want to put enough storage in the system to accommodate not only for maybe the four hours of load shifting from that day when the sun is available to the peak that night, if you want to put in enough storage to accommodate the middle of winter when you have got a week of no sun, then what you are doing is you are designing for the worst case scenario which happens very rarely, as you have to invest a huge amount of cost in the storage system, that is very rarely used, and the cost of this kind of storage is unlikely to be – well, for a very, very long time is unlikely to be viable. The cost would be prohibitive because you need not only – in fact in the figure we give some numbers, that the amount of – firstly, you have to have a very large over supply in the amount of solar field compared to the size of the power block. It needs to be designed to be pretty much 10 times larger than the power block which means you have got this huge heliostat field because you need to be able to have a big field to charge the power block when there is not much supply available. But also you need to have – you see there for these different sites we have modelled between about 50 hours and 350 hours of storage available to cover this plant through this time line compared with what is currently available is somewhere around typically eight to 12 hours.

So it doesn't mean it couldn't be done but it would be prohibitively expensive. On the other hand, probably somewhere like four to eight hours storage would be economically attractive because then you are always using the thermal storage to see you through the next night shift. So you are never putting in more than what you can use, so the storage system is well utilised and so this can be economic, so you can design for the amount of storage that makes the most economic sense rather than the size that you need to maintain constant supply and so, hybrids are compatible with this because you can still use thermal storage which increases the solar share but you can lower the cost of maintaining firm supply.

MR JACOBI: Perhaps if I can just step it back and perhaps for my benefit you might – if we can pick one of the examples on the chart and perhaps that - - -

PROF NATHAN: Yes.

MR JACOBI: - - - (indistinct) springs, the thick yellow line - - -

PROF NATHAN: Yes.

MR JACOBI: - - - and on the Y-axis, I understand what we are looking at is a probability.

PROF NATHAN: This is a probability of an unscheduled failure to meet the requirements which is – TCU is thermal conversion unit, so it is the probability that the thermal conversion unit will not be able to meet its demand due to the variability of the resource. So a probability of 10 to the minus three which you can see down there is about one day every three years for example, which is of course probably higher than what most systems would supply but this doesn't include every system. You need to look at the combination of components, you might have shut down due to a system breaking down but these things would be scheduled. So normally with a plant you might have some scheduled shut down of a plant when you know it is all – you can bring in, organise all your suppliers. This is an unscheduled shut down which is more expensive to meet. So wherever that probability you might choose to design for – so the yellow one would say for example, to meet that probability of 10 to the minus three you would need 200 hours of storage. Of course you might design for a lower amount which would have different cost implications but these are eight different sites around the world with – all with quite good solar resource.

MR JACOBI: Am I to take it the implication, or perhaps the upshot of what you have just explained is that because of the rather large requirement for an event of one in 1,000 days, for storage, you would in fact optimise the system to provide a small amount of storage but combine with a hybrid system?

PROF NATHAN: That's right. It would always be much cheaper to do that. This is just simply showing that the amount of storage you would need to maintain a firm supply would be prohibitive. It is not only because of the size of the storage but also because of the oversize of the heliostat field compared to the demand cycle. On the other hand, with a small amount of hybridisation, I mean depending on the design, it could be 50 per cent or it could be 60 per cent in the short term but longer term, there are then other fuels could be used as well. But this would always be cheaper than trying to have enough storage to maintain supply, only based on storage. So it means that renewable systems – sorry, intermittent system alone would be – are unlikely to be economic without something like a combustion backup which combustion doesn't necessarily mean fossil fuels. In the short term it probably would but in the longer term it may not, but combustion has got the flexibility to allow the low carbon component to be met at a much lower cost than trying to do it entirely on intermittents.

MR JACOBI: Can I just pick up on an answer you gave before, and you were explaining that these storage base – heat – storage base systems can be fitted to plants other than a concentrated solar thermal plant. You gave the example of coal. Are there examples of that operating in Australia at the present time?

PROF NATHAN: To my knowledge there is none in Australia but there have been some in – Germany have got some thermal storage systems. They are particularly useful in solar thermal because of the variable supply and this is where most development work has been done. But they can also be beneficial in a coal-fired power plant to allow additional surplus to be generated at certain times. There are some of these have been installed. Off the top of my head, I don't remember exactly where but I can find the details.

MR JACOBI: I think if you are coming back to where we started which was these characteristics of firm supply and flexibility, you express a conclusion with respect to the suitability of nuclear in South Australia for that reason?

PROF NATHAN: Well, I guess from the currently available nuclear technology we know that they're much less flexible than combustion systems and hence also we know that for example the current penetration in South Australia of wind and PV is such that at some periods the entire system is running on wind so this means the other systems would need to be shut down and so based on current technology then of course combustion plants are more flexible than nuclear plants. In terms of what's under development and what's demonstrated, what could be demonstrated in the future, there are other people who may speak to that, but certainly in general thought the combustion systems are definitely the most flexible plants in terms of what's available and expected in the short to medium term.

MR JACOBI: You expressed a view there that given the high penetration and the supply for renewables at certain points in time that other plants would need to be shut. I think your submission also expresses the other possibility that there might need to be additional network interconnection or power-to-fuel. Could you expand on that?

PROF NATHAN: So of course it's possible to export power into the Eastern seaboard, this would require some infrastructure investments and I think Rob is going to comment on that more in his submission later on, but currently the amount that can be exported at the moment is around about 10 per cent of the state supply. Going above that would require additional investment in infrastructure which then would need to be weighed against other potential ways to invest that money. That's of course if the plant were to be South Australia. If it was to be built into the network directly in the other eastern states, that would be another question which would need to be considered along with all the other issues around that.

MR JACOBI: I think that's perhaps where we can pick up with you, Dr Dickinson, and perhaps if we can start - your submission describes the South Australian submarket of the NEM as atypical and I'm just interested for you to explain why you say that it's atypical and what distinguishes it from other states.

DR DICKINSON: Yes, the primary issue is the combination of the very narrow bandwidth or capacity of the interconnection between South Australia and Victoria on the one hand and on the other hand the very high penetration of renewables. What that means is that at the time that we would have more than enough supply in South Australia to export (indistinct), there's no other region in the NEM that is like that; but also several other people have mentioned the fact that the demand, the minimum demand is likely to drop to near zero. We've discussed this morning the AEMO talk and Gus mentioned it and, yeah. So given that there are periods when even if sure it doesn't matter if it's five minutes or an hour or whatever, that's a substantial finite period of time that the network has to be balanced in ways that haven't been done before.

MR JACOBI: Now if we can move away from those characteristics. Your submission and perhaps I'll come in a minute to dealing with the conclusion of it but you reach a conclusion which is expressed in terms of what you described as a fixed input generator and I'm just interested in getting you to explain what you understand a fixed input generator to mean.

DR DICKINSON: Yes, so a fixed input is referring to the input to the grid not the input to the power generator. So a coal-firing power plant or a nuclear power plant under old technology, that doesn't have the ability to go up and down in terms of its supply to the grid; it's fixed, so it's a constant supply to the grid. So if you have, say, a 600 fixed megawatt inputs all of a sudden imposed on a supply that's in danger of going close to zero, then you're going to be guaranteed to get increasingly high rates of oversupply that has to be dealt with - - -

MR JACOBI: As I understand it, you would say that a nuclear generator has the characteristic of being one of these fixed generators.

DR DICKINSON: Correct, yes.

MR JACOBI: You explained a conclusion in your submission by reference to fixed input generators and I'm just interested in what was the key conclusion of your submission.

DR DICKINSON: Yeah. Any fixed input generation, in my submission I used the word fixed input, zero cost. Zero cost input, fixed capacity I guess is the very long way of putting it but it doesn't matter if it's coal-fired or if it's for some reason a natural gas-fired but it can only run on a constant output or a nuclear my conclusions are the same, that to add any fixed capacity only makes techno-economic sense for South Australia if you combine it with power-to-fuel to soak up the excess supply.

MR JACOBI: I think that perhaps before we go on and we'll have a discussion about what power-to-fuel is in a minute, but for the purposes of your analysis you undertook some modelling?

DR DICKINSON: Yes.

MR JACOBI: I think your submission contains a chart which we can put up, which is at 3.2.1 of your submission which shows and describes the circumstances that you're talking about.

DR DICKINSON: Yes.

MR JACOBI: I just think perhaps we can be walked through this slowly, so perhaps first of all if we can explain what's shown on the Y-axis and the X-axis.

DR DICKINSON: Yes, so let's start with the simplest things first. The X-axis is obviously days of the week or in a finer granular stage, granularity of actually five-minute intervals for supply and the prices. So the blue curve is the price in Victoria, it's wiggling up and down at five-minute intervals; then the red curve is the price of power supplied to the NEM in South Australia. The Y-axis, it's not actually shown there - sorry it is, yeah, I added that later. The blue and red curves are in the right-handed Y-axis so it goes from zero to 50 to a hundred, so throughout most of that week both South Australia and Victoria are reeling up and down around the sort of 20 to 40 dollars per week or whatever range.

MR JACOBI: Perhaps if I could just pick out a feature. If you look on the Tuesday which is the 16th, we see a peak appearing in the green line.

DR DICKINSON: Yes.

MR JACOBI: What's the interpretation of that?

DR DICKINSON: So the grey line and the green line are on the left-hand side and the units are gigawatts. So the green line is always positive because it's the supply of wind power in South Australia so it's kind of wriggling up and down a little bit and not providing a huge amount to South Australia's supply needs, then all of a sudden on Tuesday and Thursday, the 16th and 18th, it peaks at around 1.2 gigawatts which is fairly high because the average demand in South Australia is only about a gigawatt, about 1.2 gigawatts. The demand is not shown on this graph but nevertheless the other grey curve is the actual metered flow between Victoria and South Australia, so when the grey line's above that zero access the electricity is flowing from Victoria to South Australia and when it's below that line it's flowing from South Australia to Victoria. Is that what they said?

MR JACOBI: Yes.

DR DICKINSON: It sounds like it's backwards, but anyway. So most crucially, sorry, is the correlation or if you like the inverse correlation between the peaks in the green curve, that is, the peaks in wind supply in South Australia and the troughs in the metered flow are directly in line with each other but most importantly the red curve is also troughing in sync with the trough in direction. So this is just one example of a much bigger picture, the bigger picture being that flows from South Australia to Victoria are always associated with excess renewable or wind supply in South Australia so are associated concurrently with very low prices in South Australia.

MR JACOBI: Can you explain why you chose that particular week?

DR DICKINSON: Yeah, this is in my analyses of other - if you scale up the wind capacity you could imagine scaling up that green curve, just having a sequence of curves that goes up as you add more and more wind and you get more and more events like this. So in my submission I've got what that means in the big scheme of things but this is just one example of what's already happening in South Australia or at the border between South Australia and Victoria.

MR JACOBI: Having had a look at that graph can you explain what the implications of adding a fixed input generator to that particular system, what would that be?

DR DICKINSON: So if you added a fixed input then that would be shifting that entire green curve. Sorry, you could think of easily as shifting that entire green curve up by .6 gigawatts and so you could actually your plan is .6 gigawatts. Then at the very left hand there that's just above the dotted line, then the peaks go off the chart. But, if you like, most of the time it could well be below that line, or certainly during those peaks on a Tuesday and Thursday you wouldn't be able to go low enough because you'd be hitting the capacity of the interconnector. So it's putting even more downward pressure on prices in South Australia because the alternative is to start curtailing or shutting down wind turbines at that point.

MR JACOBI: Your explanation in terms of increasing the tendency for a negative price event by the addition of such a generator I think are shown in the second chart that you've prepared. I understand that - and perhaps correct me if I'm wrong - that the different curves with .2, .4, .6 show different size generators being added into the system.

DR DICKINSON: Correct, yes.

MR JACOBI: Perhaps if we can pick one, and perhaps the one that's at .6, given we've dealt with the 600-megawatt generator to this point.

DR DICKINSON: Can I pick two there? The red curve is the current situation. So the likelihood of zero prices is very small. It's actually finite for the curve goes below zero when it's actually a likelihood in terms of probability is a very small number. Whereas once you get up to .2, .4, .6, then, for example, it passes through zero at around about 10 per cent. That means that 10 per cent of the time the price is negative just by adding a .6-megawatt generator to the system as it stands right now.

MR JACOBI: Would I be correct in understanding that if one went to a gigawatt generator, given the point at which is zero, we're looking at about, I think reading the scale, about 30 per cent of the time - - -

DR DICKINSON: Correct, yes.

MR JACOBI: - - - one would be experiencing negative prices?

DR DICKINSON: Yes.

MR JACOBI: You've expressed the conclusion in your submission by reference to the consequence of not having power-to-fuel in the system. Perhaps if you could just explain briefly what is power-to-fuel.

DR DICKINSON: No-one else - or no-one else today anyway - surprising not even AEMO, has talked about dispatchable demand or dispatchable load; that is, power-to-fuel is explicitly being developed as, to my knowledge, the most cost effective way of dealing with this whole notion of supply going up and down. Germany is a good example with such high wind penetration and they've got lots of power-to-fuel systems. So they're explicitly deploying systems that are designed to balance supply and demand by adding load when there's otherwise excess supply.

MR JACOBI: What's the fuel that you're referring to?

DR DICKINSON: The fuel is hydrogen produced by using electrolysis systems. The chemical equation is energy in plus water equals oxygen and hydrogen. You could use photons in that sort of cell hydrogen but in the case of large-scale electrolysis when we're talking about units of a megawattage already being commercial, and that will increase in the coming years. They're pretty well talking about 40-megawatt plants producing 40 megawatts of electricity in and a pretty substantial flow of hydrogen out. Most of the systems in Germany then take the hydrogen and methanate that and it's called methanation, which is soaking up CO2 from some near-pure source of CO2, reacting it with a hydrogen to produce CH4. Throw away the oxygen into the atmosphere and you've got gas, natural gas or SNG gas, as it gets referred to.

MR JACOBI: Do you have a view about the potential markets that might exist other than perhaps the methanated product, the CH4 that you were referring to? Do you have a view about the sorts of markets that such hydrogen might be used for?

DR DICKINSON: Yes, in the very long-term mobile transport is the direction that the rest of the world is going in. People can talk about electric cars but for me hydrogen is just going to be able to jump on the main wagon of electric cars once they become commercial - if you like, benefit from the mass production cost savings of electric cars and just add the fuel cells to provide electricity to the car. But as well as that, we have ammonia, for example - clean ammonia. Right now all of the ammonia in South Australia is produced using steam methane reformation, which is taking gas, CH4, and throwing the carbon dioxide into the atmosphere and keeping the rest and combining it with nitrogen to get fertilisers. I guess if you were to just look at the market for hydrogen in Australia right now in terms of bottled gas, it's about $200 a kilogram from overseas. So any one of these small plants would just knock that market out of the water.

MR JACOBI: I understand that you undertook the analysis that's otherwise shown in the chart that we see on the screen at the moment again with a power-to-fuel plant fitted into it and - - -

DR DICKINSON: Yes. So this is exactly the same analysis with exactly the same demand and price parameter string time series. The only difference being that whenever there's supply - sorry, it's the same with wind - the three parameters are price, demand and wind power. So it's exactly the same time series for all those three but instead of - sorry, we're synthesising price from demand and wind power. So the output of the analysis is price. There's six analyses all on top of one another there because essentially by taking the excess supply, excess wind power, out of the market, the price remains stable throughout the entire periods of - - -

MR JACOBI: So am I right in understanding that what was otherwise the six curves, they're superimposed on one another - - -

DR DICKINSON: Correct, yes.

MR JACOBI: - - - in the chart that's in front of us?

DR DICKINSON: Yes.

MR JACOBI: Am I right in understanding that there's no probability of a negative demand?

DR DICKINSON: Yes, the lowest really there - you can't quite see it there. It's about $12 a megawatt hour. It's the line with the - the probability of it being below about $1 a megawatt hour is so small you can't see it. The smallest number on the excesses, from memory, I think is about 12 or 18 dollars a megawatt hour.

MR JACOBI: And if we were to go back to the chart that we had right at the start, what are the implications for that chart of power-to-fuel. Would we any longer see anything below the zero on that chart with power-to-fuel?

DR DICKINSON: No, because instead of dumping it, if - in terms of economics, the way I like to think of it is from a purely technical point of view there's this very strong engineering sense that if you've got excess of something then just dump it to someone who you think can use it. But in economic sense, it's getting rid of a low value commodity. So my vision of power-to-fuel in South Australia from an economics point of view is that you now have the ability to realise the value of this commodity of wind power and you can use it for productive things within South Australia. But what in the more economical issue of hydrogen as a fuel around Australia (indistinct) electricity.

MR JACOBI: In broad terms am I correct in understanding that this essentially involves the embedding of the energy that one's otherwise spilling into a different product from which you can market it later on?

DR DICKINSON:   Yes, and the difference between electricity and fuel is that you can store it for as long as you want.

MR JACOBI:   Just so that we're clear - - -

COMMISSIONER:   Sorry, can I just - has any work been done on the capital cost of the infrastructure that enables you to dump power-to-fuel?

DR DICKINSON:   Yes, lots.  It's a great question because there's international energy agencies tasked, as counsel assisting mentioned in the introduction of me, has only just started.  So, if you like, yes, there's been lots of analyses done of it but myself and probably 30 others around the world - 20 of them in Europe and the rest of them around the rest of the world - but our mandate is to look at that explicitly.  But nevertheless for me the exciting thing is it's not academic research any more.  If I did the mathematics, it's probably something like 50 public companies around the world that are investing in this technology, and not just investing in research projects, they're doing it.

COMMISSIONER:   Does your work have a finite time attached to it?

DR DICKINSON:   No.

COMMISSIONER:   Thanks.

MR JACOBI:   I'm just interested that just the last thing to clear up is that in terms of the addition of the generating capacity, I gather that that's not something - - -

COMMISSIONER:   Does your work have a finite time attached to it?

DR DICKINSON:   No.

COMMISSIONER:   Right, thank you.

MR JACOBI:   The last thing to clear up is that in terms of the addition of the generating capacity I gather that that’s not something that’s specific to nuclear, that that could apply to other technologies?

DR DICKINSON:   Correct, yes.  Yes, the very best example was the previous session to us this morning.  In my view any discussion of a hundred per cent renewables that doesn’t account from markets is – what’s the word?  If you believe in markets then markets will decide the evolution and power fuel is the way of enabling whatever (indistinct) in the coming decade.

MR JACOBI: You've also expressed a view in your submission about the benefit of powder fuel where you embed the energy in a different fuel as opposed to transmission. Do you have any reason for expressing the view about the relatively of either of those options?

DR DICKINSON: Sorry, say that again? I'm sorry.

MR JACOBI: I think your submission referred to you preferring powder fuel as an outcome for demand balancing as opposed to simply transmitting the electricity to another jurisdiction.

DR DICKINSON: Yes.

MR JACOBI: Do you have a reason for thinking that powder fuel is a more likely option than a transmission upgrade?

DR DICKINSON: Yes, purely cost. To do it on a very large scale would be many billions. The green grid we talked about I think it was .8 gigawatts and that was going to be 1.2 billion, so for a purely systematic point of view the way the current market works is that you have to – the infrastructure earner, for example ElectraNet, wants to be build a one gigawatt connection from Adelaide to the border and then one of the providers in Victoria wants to build a one gigawatt connection from the border to Yallourn then, yes, it makes a lot of sense technically, but they would be very hard pressed to get approval, to convince the regulator that it's cheaper to do that than it is to build a nuclear power station in Victoria for example.

MR JACOBI: Perhaps I can open this up to both of you, but do you have a view about whether there are other products into which energy can be imbedded other than fuel from these sorts of sources?

PROF NATHAN: Yes, there are many other potential products. I guess from electricity there are a number of mineral processing plants that utilise electricity; electrowinning and also, for example, the second stage of aluminium production is electrorefining, so these processes require large amounts of electricity. On the other hand there are also a number of processes that require thermal heat and these are not so well supplied by, for example, nuclear power stations – the current temperature is around 400 degrees that they operate at. The future ones may go up to 800, but many of the high temperature processes such as alumina calcination such as cement production these are at temperatures that are typically quite a bit above a thousand C so this is where either solar thermal or combustion are probably the preferred sources. If you have a fuel you could also utilise it for those high temperature processes; the fuels Robert's talked about that are based on the production of electrolysis. There are also a number of other ways for generating renewable fuel which can be either from biomass resources which could be refined and upgraded either through solar thermal, they can be gasified or from – so from non-electrical sources with heat, so electrical sources which could be wind, they could be nuclear, any of these could feed into a number of processes which use electricity directly and so nuclear could feed into those and would be actually probably better suited because most of those require, from a technical point of view, forgetting costs, most of those require a stable resource, so that if the load could be matched this would be a potential application for it. On the other hand where you have a thermal requirement then the current nuclear systems and those that are currently envisaged would be a too lower temperature for most of those and most of those would be better met by combustion or from solar thermal.

MR JACOBI: Could you give some examples of the sorts of integration aspects, perhaps from technologies other than nuclear, where you can combine a particular heat source from a generation technology with a particular industrial process?

PROF NATHAN: Sure. Typically the most common thermal power generation or the longest standing is that based on steam which is known as the Rankine cycle and this has got – the low temperature heat from this is a waste product, so any system that can utilise low temperature heat can make much more efficient use of the fuel, if you can make use of what is presently dumped through the condenser, and these are typically known as things like combined heat and power. There are many of these systems that are currently available and all of these are applicable to any steam-based power station. On the other hand a gas turbine also has got waste heat from it which is a high temperature. It can be economic to recover that from a Rankine cycle, but there are many of these – of thermal cycles that have got waste heat stream which can be utilised for some processes.

There's quite a substantial amount of low temperature, below about 250 Celsius heat, which is used in all kinds of things from food processing, steam for cleaning things through to – for example in the alumina production there's a digestion stage, you take the (indistinct) firstly digested with low temperature heat below 250 or so then you have a high temperature stage of about, in this case about a thousand degrees C, so the high temperature is best provided by combustion or solar thermal, but if there is a large industrial process it's possible to look for waste heat integration options. This is true of any thermal plant, be it nuclear or be it a fossil fuel based plant. One of the keys with these systems though is that - one of the barriers to this is that many of the processes may not need the heat all the time, so for example if you look at say the winery industry they've got a large need for refrigeration which comes at the time when they're doing all of their grape harvesting and this load could be met through an absorption cycle for example, so that you could make use of waste heat to do it, but if it's only needed for two or three months of the year it may be tricky to make the economics stack up, to have the capital cost to utilise this heat, so there's quite a bit of work being done around the opportunity to utilise waste heat and how to try and find ways to make it economic and if you have two very stable processes that are very well matched it can make a lot of sense, but it's not always easy to do that.

Certainly from the nuclear point of view it seems that probably it could be very well suited to the production of low cost electricity for a plant that needs electricity in the production such as the second stage of aluminium production. This would be from a technical point of view a very good match, if the economics stacked up that could be a good option, but for heat directly the nuclear is not so suitable. It could be for the low temperature heat, but not for the high temperature ones and most of the low temperature ones are smaller.

COMMISSIONER: Gentlemen, thank you very much.

DR DICKINSON: Thank you.

PROF NATHAN: Thank you.

COMMISSIONER: We'll adjourn till 1500, 3 o'clock.

**ADJOURNED** **[2.19 pm]**