NUCLEAR FUEL CYCLE ROYAL COMMISSION

SA NUCLEAR FUEL CYCLE ROYAL COMMISSION

MR KEVIN SCARCE, Presiding Commissioner
MR CHAD JACOBI, Counsel Assisting

SPEAKERS:

MR BRIAN GIHM, Product Manager at HATCH
MR DAVID DOWNING, WSP | Parsons Brinckerhoff
MR KENNETH GREEN, Sargent & Lundy
MR TIM JOHNSON, Jacobs Engineering Group
MR NIGEL SULLIVAN, Jacobs Engineering Group
MR ROBERT RIEBOLGE, Consultant
MR DAVID LENTON, Consultant
MR CRAIG MICKLE, Ernst & Young
DR JYOTHI GALI, Ernst & Young

TRANSCRIPT OF PROCEEDINGS

ADELAIDE

9.00 AM, TUESDAY, 6 OCTOBER 2015

DAY EIGHT

PROCEEDINGS RECORDED BY SPARK AND CANNON

COMMISSIONER: Good morning. I welcome you back to topic, workshop on estimating the costs and benefits of nuclear activities. The Commission's terms of reference is required to express a view about the conditions under which a range of nuclear fuel activities would be viable. Today's public session is concerned with how the Commission plans to approach an assessment of the potential economic or commercial viability of further processing of radioactive materials, nuclear power generation, radioactive waste storage and disposal activities in South Australia. The Commission has engaged experts in relevant fields to undertake estimation studies of a range of hypothetical scenarios. The scenarios represent some of the activities that the Commission needs to consider under its terms of reference.

The scenarios themselves, as will be explained, are defined in very broad terms. They do not assume a particular site on which a facility might be developed, nor do they cost a specific facility or project such as would be necessary if assessing whether a particular activity or project oughtn't proceed. Instead, what is to be estimated is intended to be indicative of the range of potential viability of the activity and, therefore, to assist the Commission to take a view on the conditions under which the activity broadly might be viable in South Australia. The nature of the estimation work in the broadest terms has been disclosed in the statements of work available through the links on the Commission's website.

The purpose of today's public session is to inform those interested of the nature of the inputs and methodology of the estimation exercises being undertaken. It will also disclose the types of outputs those estimation exercises would produce once they're complete. The estimation work will be undertaken in the coming months. Those that are interested may, if they wish, comment on the inputs and the methodology as explained today by writing to the Commission at the email address found on the flyer for today's session. Such comments need to be provided by the end of next week. Comments directed to the inputs, methodology and the kinds of outputs will be considered by the Commission and those undertaking the estimation work.

Because of the more narrow purpose of today's public session, the format will be different from other sessions. Instead of proceeding in a question and answer format, those undertaking the estimation work have in advance been requested by the Commission to describe the purpose of the work, the nature of the inputs, the estimation model being used and the types of outputs that will be produced. These will be presented to the Commission this morning. The results of the estimation work will be disclosed by the Commission in February 2016 when it releases its tentative findings.

Finally, it should not be assumed that because the Commission has requested an estimation as to the potential viability of various activities that it may recommend in due course that those activities ought to be undertaken. As the Commission has explained, there is much more to consider. Potential impacts on the community and the environment must also be considered and weighed as part of the consideration as to the overall feasibility and desirability of any of these activities. However, the Commission must, under its terms of reference, consider potential commercial viability and that is the purpose of commissioning this specialist estimation work. Mr Jacobi.

MR JACOBI: Today's first session is quantitative analyses and business case for uranium conversion, enrichment and fuel fabrication facilities in South Australia. Quantitative analyses will be undertaken to determine engineering, procurement, construction and life cycle operating and maintenance costs associated with the possible development of facilities in South Australia for the processing of uranium oxide into fuel for use in nuclear reactors. The case studies to be considered are the establishment of conversion, enrichment and fuel fabrication processes for a light-water reactor and conversion and fuel fabrication processes for a pressurised heavy-water reactor. To that end the presentation and evidence will be given by Mr Brian Gihm of Hatch Pty Ltd.

COMMISSIONER: Brian, would you please proceed. Brian, I think you're muted.

MR GIHM: Yes, sorry about that. Good morning, everyone. My name is Brian Gihm. I am the product manager at Hatch undertaking the study of fuel processing facilities for South Australia. I'm going to start with the presentation overview. I will be discussing the study objectives, have a brief discussion about nuclear fuel cycle, what are the base-case scenarios, process overview and base-case scenarios, finally some modelling and we'll be discussing inputs to finance our models, including high-level assumptions, facility sizes (indistinct) and product cost calculations, also infrastructure assumptions, contingency assessment and high-level assumptions and exclusions in this study.

Next slide. The study objective is to investigate the potential business case for establishing uranium conversion, enrichment and fuel fabrication facilities in South Australia. In order to achieve this we will estimate the direct and indirect capital cost and fixed and variable operational costs for uranium processing facilities. We will estimate life cycle project cost of the facilities, including engineering, construction, procurement, commissioning, operation and decommissioning activities. We will also investigate the investment justification based on possible service revenues.

Next slide. If I present a simplified study overview, currently the fabricated light-water reactor fuel cost is between $US1500 to $US2000 per kilogram. In 2014 the yellow cake export price from Australia was $92.80 per kilogram. The (indistinct) that this yellow cake is enriched to 4 per cent and used as light-water reactor fuel we will be requiring 8.7 kilograms of yellow cake. So now the question is, in that present value what is the life cycle processing cost of uranium, and if we subtract yellow cake cost and life cycle processing cost from fuel sales cost, what will that be? So in this study I will estimate the levelised cost for yellow cake processing to be nuclear fuel such that we can see what is this residual cost after we subtract all the facility costs and yellow cake cost from fuel price.

MR JACOBI: Mr Gihm, can I just ask you a question back then?

MR GIHM: Yes, sir.

MR JACOBI: You referred to a price for uranium oxide. Was that a price in Australian dollars or US dollars. The price for fuel was in US but the price for yellow cake, was that in Australian dollars or US dollars?

MR GIHM: The price for yellow cake was in Australian dollars. This is the overview of the nuclear fuel cycle. In this study we will be focusing on the front end cycle facilities but not including uranium mining. So we will be discussing conversion facilities, enrichment facilities and fuel fabrication facilities. Next slide. There are three basic case scenarios that you can consider. First case is having conversion facility only, second case is conversion and enrichment facilities and third case is having conversion, enrichment and fuel fabrication, all three facilities. For fuel conversion facilities we are examining two types of facilities. The first one is conversion. The second one is dry conversion. We will be examining three different configurations. We will be examining configurations such that they can produce either 100 per cent LWR applicable fuel or both LWR and pressurised heavy-water reactor fuel in 90 per cent and 10 per cent split.

We will be also examining one enrichment facility which is gas centrifuge technology. There will be two fuel fabrication facility configurations. Again, this will be configured to produce 100% LWR fuel and the other configuration to produce 90% LWR and 10% HWR fuel. For the business case, there are (indistinct) possible scenarios when you combine both configurations, including brown-filled and green-filled (indistinct) there will be 16 best case scenarios.

It will be modelled at all facilities located at single location, but within their separate (indistinct) the process overview in a little more detail - on the far left side, there are three boxes which form the conversion facilities. Left bottom is the (indistinct) facility (indistinct) process the two Uranium Hexafluride and it is fed into gas centrifuge for (indistinct) in fuel fabrication, it is essentially a two stage process. The first is Uranium Hexafluride to Uranium Dioxide conversion. Second portion is the actual fuel fabrication. Next slide.

So these are eight possible scenarios that we will be examining and the final product, LEU, means low emission uranium, which is used for light water reactor fuel. NU is the natural uranium which is used for PHWR fuel. Next slide. So what we are essentially trying to do is create a financial model which is based on (indistinct) capital product analysis approach of using discrete cash flows, discrete time period and accounting of cost to evaluate the product's net present value and internal rate of return. We will be performing statistic analysis and to evaluate the impact of CAPEX and (indistinct) variations at present value and the internal rate of return. Next slide.

In order to provide inputs to this financial model we will be estimating the following inputs that are fuel service revenue, production rate, initial capital cost for both direct and indirect cost, and operating cost which really includes variable and fixed cost, plus sustaining capital cost, and facility closure cost. Next slide. This is one of high level assumptions in our study. Uranium production and (indistinct) is entirely dependent on nuclear fuel generating capacity changes only. So these fuel facilities will not impact the demand or supply of uranium. Uranium market is a restricted market. There are insignificant quantities of these services being traded on exchanges and majority of fuel sales are on the long term contract.

So what will be impacted if these hypothetical possibilities are introduced, it will impact conversion (indistinct) and fuel fabrication (indistinct) services. Next slide. This is a revenue assumption. We will be using poor service model for the best case scenarios and the financial modelling. In (indistinct) services, the facility is contractually obligated to process customer owned uranium. These facilities provide services, conversion enrichment and fuel fabrication services only. They do not actually (indistinct) any of uranium. These services are not exposed to locate (indistinct) directly.

The service contracts are typically charged as a fixed price per kilogram of uranium or per separative work unit, which I will be using (indistinct) and they are generally adjusted for inflation. Contrary, most nuclear fuel service companies operate their facilities under (indistinct) service model, which includes chemical, general electric (indistinct) and capital electric nuclear fuel in Korea. Next slide. When you look at the poor services for conversion we have found very strong correlation between the global Uranium Hexafluride price and the (indistinct) price (indistinct) therefore the long term conversion service price is expected to be predictable.

For (indistinct) we will be using service award market long term (indistinct) price forecast, which is US Dollars 67 per pound, however it is not a factor impacting on this case in poor service model. Next slide. For (indistinct) services we also found that there is a positive correlation between the spot SW price and yellow cake price. Therefore (indistinct) revenue can be reasonably obtained, however there are many uncertainties, including secondary market supply and social political factors that will be impacting SW price.

The licence fuel fabrication price - we were not able to find there was any direct correlation between yellow cake price and fuel fabrication price. The reason is that fuel fabrication services are traded in the long term private contracts and incident quantities are traded (indistinct) most fuel facilities are strategically located in the country which is country utilising nuclear power. Next slide.

The following are our assumptions in sizing these facilities for modelling. We sized the conversion (indistinct) and fuel fabrication facilities based on 10,000 tonnes of uranium processing per year. These are based on two assumptions. The first is that the international energy agency products that global nuclear power generation capacity will grow by 37% from 2014 to 2030. Today's generating capacity is 376 gigawatt and in 2030 international energy agencies expecting the generating capacity to be 518.6 gigawatt. The second assumption is that Australia will maintain the current uranium market share. In past 10 years Australia has produced and exported about 7,400 tonnes of uranium per year and by increasing this amount by 37% we are expecting that roughly 10,000 tonnes of uranium will be produced and exported. Next slide.

We are using two different facility configurations. The first configuration is that the (indistinct) from these facilities will (indistinct) in 90% and 10% split for light water reactors and (indistinct) fuel, and the second case is that only 100% of light water reactor fuel fabrication will be considered. These configurations are based on the current installed capacity of light water reactors and pressurised heavy water reactor plants in the work. Their proportions are approximately 93% and 7% respectively. The annual natural uranium consumption by these two types of reactors - light oil reactors and HWR proportional to the installed capacity, and these numbers are 94% and 6% respectively. Next slide.

So our model facilities are roughly 10% of the global capacity in 2013. For conversion facility, it will represent roughly 10 to 13% of the global capacity. The (indistinct) facility will represent 8 to 10% of the global capacity and the fuel fabrication facility will add 8 to 9% of light water reactor fuel capacity and 23% of HWR fuel capacity. Next slide. Now I will discuss how we are calculating the capital cost. It is expected that the (indistinct) of capital cost will incur during procurement and construction stages. Our estimates will be based on the existing commercial facilities for conversion enrichment and fuel fabrication, and assembly facilities.

We will identify the most capital and operating costs intensive mechanical (indistinct) and their cost, and installation (indistinct) and all these costs, and labour hours will be individually estimated. For small (indistinct) such as pumps and valves, they will be added as percentage values of the major (indistinct) cost. The capital cost for electrical (indistinct) and civil structural components are estimated as percentage values of building and site direct costs. Next slide.

For operating experience calculation, major cost model and energy costs are individually calculated, or some are scaled from similar facilities. Major costs, including general maintenance and security, are scaled from similar facilities. It is expected that the majority of labour cost will incur during procurement, construction, commissioning and operation phases.

Next slide. Project costs such as build of, materials and labour for engineering, construction, commissioning are estimated from Hatch's past EPCM experiences in similar chemical, mechanical and high-tech chemical plant projects. Nuclear costs and productivity factors are applied whenever required and regulatory and licensing costs are (indistinct) that these requirements will be similar to the Canadian requirement. That is because we reason that South Australia and Saskatchewan in Canada share many similarities such as having large uranium reserves, having many active uranium mines, mining industry, but not any of the fuel processing facilities.

MR JACOBI: Mr Gihm, can I just interrupt you there. You referred to there being a project cost based on Hatch's experiences with projects in Canada. I'm just interested whether there's any cost uplift for the Australian context.

MR GIHM: Yes, I will actually get to that point in the next few slides. The last one is the decommissioning cost. This will be based on projected decommissioning costs of similar facilities. So, as you just asked, the reference plant cost will be initially estimated in the currency of the country they are presently located in but these costs will be adjusted for South Australian local conditions by applying recent specific material and labour cost and productivity factors. (indistinct) and power-(indistinct) ratios will be applied whenever this direct South Australian cost cannot be obtained for certain plant components and labour. You should know that the cost estimates are order of (indistinct) of completions at this stage and they are based on several assumptions made in this study.

So for reference point we are examining several reference plants listed in this presentation but they also include other facilities to increase our estimate increases. So for conversion facilities we are looking at wet and dry conversion facilities. For wet conversion facility we are using Cameco's Blind River refinery and Cameco's Port Hope conversion facility as the reference plants. For dry conversion facility we are using the Honeywell Metropolis facility in the United States as the reference plant. Conversion facilities are essentially chemical plants.

Next slide. For enrichment facility we will be examining the second generation technology which is gas centrifuge. A gas centrifuge plant is essentially a mechanical plant. We will be using the Urenco USA facility as the reference plant and we will be using Urenco TC21 centrifuge as the cost modelling basis. Next, please. For fuel fabrication we will be looking at conversion, plant production and assembly. So for conversion it will be conversion of uranium hexafluoride to uranium dioxide through integrated dry route process.

For production and fuel assembly we will be looking at the assembly and production cost for light-water reactor fuels and HWR fuels. For LWR fuel we will be looking at AP1000 fuel, EPR fuel and G (indistinct) reactor assemblies. For HWR we will be using CANDU 37-element bundle as the reference bundle. We'll be using Cameco plant in Canada and Westinghouse plant in USA and KEPCO nuclear fuel plant in Korea as the reference plants for this analysis.

Next, please. For site infrastructures we are looking at transportation and road requirements which can transport about 40 tonnes of materials per day. We do not expect that we will be requiring any rail access. For power requirement we are looking at a total of 80 megawatt. Of this 10 megawatt will be used for conversion, 50 megawatts will be used for enrichment and 20 megawatts will be used for fuel fabrication. In terms of labour requirement we are looking at approximately 2000 people working at the site during the operation. This includes 500 for conversion plant, 250 people for enrichment plant and 1200 people for fuel fabrication plant. For water requirement we are looking at approximately 1.5 million cubic metres per year and most of this water will be consumed by the wet conversion facility and for fabrication facility.

For site we will be looking at brownfield and greenfield locations and some of the considerations are access to 275-kilovolt transmission line and access to nearby port facility. Some of the possibility are co-locating the fuel facilities with other nuclear facilities that are being studied, (indistinct) power plant and waste repository. The last possibility is the site could be near existing uranium production facilities.

MR JACOBI: Mr Gihm, can I just interrupt you there. You've identified certain labour figure assumptions. I'm just interested in the basis for those labour figures that you've identified.

MR GIHM: Sorry, I couldn’t hear you clearly. Could you repeat the question?

MR JACOBI: You've identified certain labour figure assumptions for the plants. I'm just interested to understand the basis for those assumptions.

MR GIHM: These are based on the existing facilities. For wet conversion facilities the numbers vary between 300 and 800. For enrichment facilities of 7 million SWU size the number seems to be consistently 250. Fuel fabrication facility numbers vary a little bit but 1200 people is based on Westinghouse fuel manufacturing facility in the United States which, coincidentally, produces 1200 metric tonnes of fuel per year. Did I answer your question?

MR JACOBI: Thank you.

COMMISSIONER: Proceed.

MR GIHM: Next slide, please. For project risk and contingency assessment we will be utilising the following method to identify the project contingency factors in our study. The identification of project risk affecting (indistinct) and facility schedules will be done first. We will be creating risk identification tables and qualitatively determine what are the potential impacts. Some of the risk items include construction, licensing and regulatory availability of skilled labour, infrastructure, technology strategy and contracting strategies such as EPC versus EPCM. Cost impact will be quantitatively assessed. Impact will be ranged to evaluate the most likely optimistic and pessimistic scenarios and we will be conducting multicoloured statistical analysis to determine contingency levels for project risks. Schedule contingency will be qualitatively assessed at this point.

MR JACOBI: Mr Gihm, you just used two acronyms, EPC and EPCM. Can you explain what they are?

MR GIHM: EPC is basically a turn-key project. It's engineering, procurement and construction. EPCM is engineering, procurement and construction management. So with EPC model the vendors generally assume the whole risk of completing the project under fixed price and the vendor will charge a certain percentage of the capital cost of project as the risk premium. Under EPCM the vendor will be only managing the project for the owner. Therefore, the vendor does not assume the risk for delivering the project with fixed price. Therefore, the risk basically falls on the owner and there is no risk premium associated with EPCM.

MR JACOBI: Thank you.

MR GIHM: So the last slide is the exclusions. This study excludes the following considerations: cost for regulatory and legal framework set-up, sociopolitical factors, secondary supply of enriched uranium, inter-government (indistinct) which is expected to be necessary for the enrichment facilities, cost for marketing and customer relations and all cost factors that will be incurred outside of the facility boundaries and any other classified information that's associated with costing. Thank you.

COMMISSIONER: Any questions? Brian, thank you very much for your evidence. That concludes the first session. For those who are following us on the stream, the copies of the slides will be available on our website later today. I now adjourn until 9.45.

ADJOURNED **[9.30 am]**

RESUMED **[9.46 am]**

COMMISSIONER: We reconvene at just after 9.45. Mr Jacobi.

MR JACOBI: Quantitative analyses and business case for establishing a nuclear power plant and systems in South Australia. Quantitative analysis will be undertaken to determine engineering, procurement, construction, life cycle, operating and maintenance costs associated with the possible development of three different types of nuclear power generation facilities in South Australia. The types of facilities to be considered are the small modular reactor SMR, the pressurised heavy water reactor and the light water reactor. Undertaking that work and to give evidence are Mr David Downing, Parsons Brinckerhoff and Mr Kenneth Green of Sargent & Lundy.

COMMISSIONER: David and Kenneth, a very warm welcome this morning.

MR DOWNING: Thank you.

MR GREEN: Thank you.

COMMISSIONER: All yours.

MR DOWNING: Okay.

COMMISSIONER: Please proceed.

MR DOWNING: Thank you. Good morning, thank you for the introduction and thank you for the opportunity to make this presentation to the Nuclear Fuel Cycle Royal Commission. Presentation will be focussing on the methodologies and assumptions that we have been developing over the last few weeks. We would ask you to bear in mind that the study we have been performing is still ongoing and that our work is still being reviewed and revised as we proceed. Next slide please. The brief we received from the Nuclear Fuel Cycle Royal Commission is ultimately focussed on developing a business case around the possible development of nuclear power plants in South Australia that might enter in to operation around about 2030. We were asked to focus on modern technologies that would be commercially available around 2030. The brief identified certain reactor technologies but it was essentially wide ranging in this regard.

We were also to consider what the infrastructure requirements of the plants might be. What additional road, rail, transmission, infrastructure, et cetera might be required? And we were asked to put all this in to a South Australian context. The business case will draw on the whole of life cost estimates and performance projections of the facilities in order to identify what commercial returns might be achieved versus what might be the expectations of developers and financiers. We are to identify what development risks might exist and what measures might be required to facilitate investors' participation in a nuclear power plan project.

MR GREEN: We are aware that you have already received a considerable amount of information about the interest and technical aspects of the various facilities that could be built. We reviewed the potential available technologies in the market from a standpoint of how many unique cases we had to look at. In other words, we are not looking at specific technologies, we are looking at categories. So we started out with what are called the evolutionary designs. These are plants that currently exist, either in construction or in actual operation and in some cases; these are plants that have had a number of years of operation, ABWR for instance. These are usually termed as active safety plants and we will talk a little bit more about that as we move on. In looking at these, we have come to the conclusion that for the light water reactors; these will fit in to the category with the advanced reactors that have more passive design. Right now if you were buying one today, these would potentially have economic advantages but when the advanced reactors are in an enth of a kind situation, a lot of that economic advantage will probably go away. The exception here is the enhanced CANDU 6. We looked at that separately simply because it has a different size. It is the only reactor that we are looking at in evolutionary or advanced reactors that comes in in the mid-range, approximately 700 megawatt electrical. Because of that uniqueness we did include it as a separate case. The advanced reactors have – they are called passive reactors; they have some element of passive design and we have to remember that is a sliding scale. Now instead of having immediate active systems, these have active systems that come on days after an event. They are still not truly passive from the standpoint of what is called walk away passive but they do have an enhanced ability to wait until you have active design implementation.

In looking at these, we see three distinct types; two light water reactors, a pressurised water reactor and a boiling water reactor. Then we have a heavy water reactor. So we considered each of those as a category and again, the ones listed here are the ones we had most information available for. They will encompass other potential designs that may be in the marketplace in the future. In particular, the AP-1000 is of interest simply because of the amount of data we have and reliable information we have to set a benchmark for the cost of future plants. We will talk a little more about that but there is some real momentum. Eight units currently under construction, four in China, four in the US, a number more planned for China. At least eight more are in the licensing process in the US. So from a standpoint of momentum, there is a lot going on here and because of that there is a lot of information available.

Small modular reactors, this falls in to a little different category in that we do not actually have an active project being built in a small modular reactor. However, there is a considerable interest. We have listed four small modular reactors. We probably could have listed 12 or 15 if we had wanted to because there is so much being looked at out there. These four listed, NuScale smart, the Holtech SMR 160 and the mPower because these have a clear position in licensing. In other words, they have the potential of being licensed, being able to be ordered, so that they could be online before 2025 and so that is what qualified them. Again, they represent all the others that might come in, by 2030 it might be a different landscape. We chose to actually model this with two examples, the NuScale and mPower. And the reason we did that is because they represent kind of the end of the range, small modular reactors are not all the same size. NuScale is less than 50-megawatt electric per module, so we looked at combining six of those in to something that would approach 300-megawatt for an installation. On the other hand, the mPower is 180-megawatts per module, so we looked at putting two of those in to a facility that would give you 360-megawatt total. So we looked at those two cases.

I guess we are back to David on this.

MR DOWNING: Yes. No problem. So anyway, having reviewed the available technologies, the next part of our brief was to assess the information we were able to compile and to model the whole-of-life costs of the development of these nuclear power plants for South Australia. The outcomes of the modelling will flow in to a business case that will demonstrate whether or not there is an economic viability for the projects. To perform the modelling we have to develop a range of economic cost revenue, performance and schedule assumptions for the whole of the life of such a facility; from design and development, through construction and operation to decommissioning and final site remediation. The economic model will calculate the net present value of the facility's cost and revenues to determine the levelised cost and levelised price of electricity. Economic assumptions range from macro economic assumptions on cost escalation and foreign exchange rates through assumptions specific to the assumed nuclear power plan business model, to assumptions on revenues to be generated based on wholesale electricity pricing. Escalation of operating costs has been assumed to be consistent with that used in the Australian electricity technology assessment at 2012. As much of the reference data we have been using is expressed in US dollars, we have used an interim assumption on exchange rates pending confirmation of forecast rates for economic modelling.

Wholesale electricity pricing is being forecasted by another adviser to the Royal Commission, taking in to account the forecast changes in South Australia's generation mix in response to international and Australian climate change obligations. The weighted average cost of capital is frequently used in net present value analysis to identify the break even internal rate of return of a project. For the purposes of this study, a weighted average cost of capital has been estimated based on what is considered to be a reasonable business and financing model for a nuclear power plan in South Australia. In making this assessment, we have assumed some significant de-risking measures would be addressed. For example, recent nuclear power plant experience shows that investors want to see long-term revenue certainty. The US AP-1000 project and the UK's Hinkley Point project all show strong elements of revenue certainty in their financing by way of long term PPAs and in the case of Hinkley Point, a government sponsored contract for difference. Similarly, the same projects have strong loan guarantees to give lenders further assurance of the soundness of their investment. On this basis, we have assumed a model that resulted in a pre-tax real WACC of 10.47 per cent. This compares favourably with the range of discount rates used in other studies such as the Imperial College study of 2012.

MR GREEN: As I said, we heavily depended upon the information from the Westinghouse AP-1000 projects to provide essentially a benchmark. At any point in time, whether it is 2020, 2025, 2030 it will be a competitive market and the AP-1000 because it is an actual project that is being built will, I think, set a benchmark that if someone cannot compete with that, they won't end up in the market. The other issue with the Westinghouse AP-1000 that makes it attractive is that the information is a very high reliability. The two projects in the US, the four units, the Vogtle and Summer projects are being built in a regulated environment. By that we mean that the cost of a plant has been approved based on being able to recover the cost in a regulated electricity market. So the costs have to be publicly reported and they are actually broken down. The costs that are reported are the original contract costs, the escalation that is allowed for under the contracts and they even report a certain quantity of the cost that is under dispute currently between the supplier and the owner. But with all that information, we have got a very reliable basis for what those plants are actually going to cost.

Those plants are first of a kind plants in the US and China, however they are being built on existing sites, so we factored that in to what we believe the enth of a kind cost would go to that would be applicable to South Australia but of course there would be first of a kind cost with being the first nuclear unit. Extrapolating that information to the other options, the boiling water reactors historically have not been greatly different in price. There has been a certain window of pricing and boiling water reactors and pressurised water reactors have fallen in to that window, one being more competitive than the other depending on the particular situation. So we did not differentiate in capital costs between those. The heavy water reactor is a little different situation. The historical experience in Canada is that the heavy water reactors that had been built there have cost more than corresponding plants in the US that would be of similar size. There's actually a reason for that. As we look at it, part of the heavy-water cost, the heavy-water management systems, the relatively large size of the plants – so it is logical that there is some increased capital cost with these heavy-water reactors. So we've factored that in. Because there are no current firm orders for heavy-water reactor we have no way to verify. However, the only thing we have, the EC6, the smaller CANDU, has been proposed for Romania and what has been reported in the press is the costs of that project are relatively high. Again, we don't know too much about the details of that but that's being proposed, I believe, by a Chinese organisation working with the Canadians. Still, it looks like a fairly high capital cost. So based on that we did estimate a higher capital cost for that.

Next slide, the small modular reactors. Of course, again we're dealing with situations where we don't have any contractor to look at. We don't know what the actual offering will be when these start to be built. We've seen reports over the years, this $5000 per kilowatt electric capital cost thrown out there. We don't know what scope of supply that would actually cover. We don't know what point in time those dollars are relevant to, US dollars of course. So we kind of discounted that as being a number. We did notice in the earlier information and a presentation you had on the smart reactor that they were quoting prices in the $US9000 to $US10,000 per kilowatt. We think there's a reason for that and the reason is they're talking about the Saudi project which is very much a first of a kind.

They're also talking about stand-alone designs of 100 megawatts, whereas in looking at others like the NuScale, the Wholetech, the mPower, we're talking about putting multiple modules together to get up in the 300-megawatt range. So there's some economies there. So we don't know that that's inconsistent with what we're predicting which are slightly elevated numbers. There's the very excellent study done last year in the UK on small modular reactors that came up with a range of estimates of $US6400 to $US8900 and we think that is fairly consistent with what we're seeing. So we've got some good information there.

Will they be successful with a larger cost than the larger plant options? Obviously they're aiming at a market that the larger plants can't go into but we think they have some chance of being successful, even competing head to head, simply because of the potential advantages in the less infrastructure costs required to support it and also the ability to phase in generation to more closely match the load growth. So we do think part of the success of the SMRs will depend on there being able to succeed in a large market also because they need to get the volume up.

MR DOWNING: So if we move onto the capital cost assumptions that we've made, what we've put in here in our capital cost assumptions, the light-water nuclear power plant capital cost therefore are estimated from the reported experiences with the recent AP1000 projects. Heavy-water plant capital costs have been estimated to be higher than those of the LWR plants, reflecting the Canadian versus US cost history. Additionally, please note on the CANDU plants there's a significant life extension refit cost that has to be factored in after about 30 years of operation. That's not just a capital cost. It's also about two years off. So that has all got to be factored into the modelling.

SMR costs have also been factored to be slightly higher than the large-scale light-water reactor plants, though not as high as some reports have been suggesting, owing to, as Ken states, our belief that they need to be cost competitive with the large-scale plants to be successful in the market. These costs are all expressed in US dollar terms and what we have done for the CG modelling that has been done by others, we're separating out the local components of these costs and modelling those separately in order that the economic impacts of the developments can be modelled by the CGT.

To infrastructure requirements, every power plants needs support infrastructure, the scale of which can be highly site specific. Now, numerous submissions to the Royal Commission have suggested locations for a nuclear power plant in South Australia. Other submissions have dismissed or debunked those sites. Location obviously is a contentious issue. So what we have done is we've – for the purpose of this study we are not focusing on any particular site, any particular location. We're considering generic greenfield and brownfield sites. The descriptions have been supplied to us, agreed with the Royal Commission. For these locations we've identified appropriate high-level scopes of supply and, therefore, costs of infrastructure that can be used as building blocks with the power plant costs to estimate the total project costs.

Road and rail infrastructure is basically independent of power plant size. The greenfield concept assumes that the plant will be 50 kilometres from the nearest appropriate infrastructure. So we've estimated the cost of 50 kilometres of roads and rail links together with the works required to connect to and refurbish any existing infrastructure around the connection point. For the brownfield concept we've basically done the same thing but we've just estimated the cost of short spurs from the infrastructure into the power plant itself. In all cases we've assumed that the infrastructure will be built to the appropriate local and national standards.

Nuclear power plants, like all thermal power plants, use steam turbine generators to generate power. Steam turbines, whether in a nuclear or a conventional power plant, nearly always require significant quantities of water, primarily for cooling the steam exhaust in the steam turbine. If a plant is located close to open water, such as on a coast or a river, water is often pumped directly from the source, through the condenser and returned to the source, so-called once-through cooling, but this requires a significant volume of water to be used. Alternatively, if sufficient water is not available for once-through cooling a closed-loop system with cooling towers or cooling ponds might be used. Water that's lost by evaporation in the cooling towers or the ponds has to be made up by adding water to the cooling water circuit but the net consumption of water is much less than in a once-through system.

We've estimated the water quantities required in order to define the water supply systems necessary. Water consumption, therefore, on whatever scale is clearly a challenge. Pumping water over long distances can incur significant costs. The higher the volume, the higher the cost. We believe that the volumes required for large-scale plants would be impractical to supply over any distance and that once-through cooling from a nearby source would be required. Similarly, the volumes required for once-through cooling of SMRs would be impractical, but SMRs equipped with cooling towers would be more flexible. The cost of once-through cooling facilities has been accounted for within the capital cost estimates of the plants themselves. We've estimated separately the cost of raw water supply systems for SMR power plants using cooling towers for cooling.

On electricity transmission South Australia, ElectraNet, has a very mature transmission network. It's appropriately sized with the demands imposed on it and it has existing generation units connected which range in size up to the 260-megawatt units at Northern. Most generation is connected to the 275-kV network which interconnects with Victorian network down at Heywood near the Portland smelter. For the estimation of the cost of transmission infrastructure assets we've adopted a building block approach using cost estimates developed for the electricity transmission cost assumptions component of AEMO's 100 per cent renewable study in 2012. We've continued with generic greenfield and brownfield assumptions associated with the distance from the plant to the nearest infrastructure. The nearest shared infrastructure we've assumed for transmission purposes will be rated at 275 kV for the SMRs but 500 kV for large-scale plants.

Part of a requirement from the Royal Commission was to develop some additional electricity transmission building block costs. The brief from the Royal Commission provided descriptions and a selection of electricity transmission assets for consideration in parallel with the nuclear power plant assessment. These costs have not been included in the nuclear power plant modelling itself but can be used to estimate the effects of variations in the connection options. These asset descriptions cover the cost of constructing new 500-kV and 275-kV transmission lines and substations as well as the cost of HVDC interconnectors for a range of capacities.

So apart from capital costs we have operating costs. The operating costs of a nuclear power plant are largely fixed. Operating costs that are actually variable with output are very low and not material in relation to the whole. The US Nuclear Energy Institute routinely collects operating cost data on the US fleet of nuclear Power plants which allows us to be reasonably assured of the operating cost estimates we are making. Operating cost data is often, even routinely, published as dollars per megawatt hour or cents per kilowatt hour. This can give a false impression that the operating cost is variable, however costs are expressed in this way so that they can be compared more easily with benchmark retail costs, for example. Importantly, these costs are based on the premise that the plant operates on a base load.

Decommissioning costs are treated as an operating cost. A fixed annual cost is allocated to fund a reserve account that accumulates the amount estimated to be required for the 60 year care and maintenance, and the decommissioning period after operation ceases. The nuclear energy institute also maintains good reference data for nuclear power plant fuel costs. Again, fuel cost is usually expressed as a variable cost, however unlike conventional fuels, nuclear fuel and spent fuel costs are not truly variable. Nuclear fuel has a limited life and it is routinely moved around the reactor and replaced according to a regular schedule.

The rate at which fuel is used by the power plant is therefore time based, not output based, so the cost of fuel and the cost of dealing with the spent fuel are essentially fixed. Transmissions costs are expressed as a use of system charge and they're a culmination of fixed and variable components. These again are published by AMO and we've taken those numbers from the latest AMO reporting. For technical assumptions we've taken representative examples of each technology to model. For the live scale reactors, we've assumed single unit power plants. For the small modular reactors we've assumed a number of units that result in a power plant in about 300 megawatts.

One of the major assumptions deals with the capacity factor of the power plant. Capacity factor is a measure of how much energy a power plant actually produces over a period of time, in comparison with what it could produce if it were running 24/7 at (indistinct) capacity. It takes into account allowances for unplanned forced outages and planned outages such as those for core refuelling. It also takes account of those occasions when generation can accede a plant's nominal electrical output because the plant's normally rated on a thermal basis for the reactor output.

Capacity factors have consistently improved in recent years. Capacity factors of 96% excluding the refuelling outages are now being achieved. A long term average in the low 90s, including an allowance for refuelling is a realistic and prudent based case in new third generation plants. On the schedules, the fundamental assumption that we have is that the nuclear power plant will enter into operation around 2030. This will be preceded by pre-construction for site assessment, licensing, permitting et cetera and construction periods which are appropriate to the technologies. We've assumed that SMRs will be subjected largely to the same regulatory process as large scale plants.

It may be possible that the regulatory frameworks and assessment regimes might be relaxed somewhat, but this is far from certain. So we've taken the prudent view that similar requirements and therefore schedules will apply. We've assumed a 60 year operating life, which is the planned life for all modern designs, and we've assumed that there will be up to 60 years of care and maintenance of the inactive power plant, which is required to allow the installed components to cool down prior to them being safely dismantled, disposed of and the site remediated.

So what are we looking for from the modelling? The modelling outputs focus mainly on the net present value of lifetime costs, lifetime revenues and lifetime generation. Using those, we can develop the associated levelised cost and levelised prices of electricity. Based on the assumed weighted average cost and capital which is used as a discount rate in the calculation. We also break out constituent components of cost to identify those which have the greatest effect on the total, and therefore those on which to focus our sensitivity assessments.

Modelling outputs will also include aggregated costs over the life of nuclear power plants to be used as inputs to the CGE model. The detailed business case will then build on the modelling outputs to assess the nuclear power plants commercial viability, and to identify any funding gaps. It will consider the sensitivity of the modelling to variations in a range of factors and the impact that these might have on the facilities' commercial performance. The business case will also describe the developmental risks to a nuclear generation facility. It will describe what matters and central financing partners will consider it important to address, to facilitate their participation in the project.

That basically concludes our presentation. As we said at the beginning, please bear in mind that this is still an ongoing piece of work. We continue to review and refine our assumptions. We will continue to do so within the next few weeks before our final report is presented to the Royal Commission at the end of the month.

COMMISSIONER: Dave, can I just get an idea of the sensitive analysis that you are going to do around pre-construction and construction in terms of time frames.

MR DOWNING: Basically the time frames we're looking at, basically are plus or minus one year at the moment and the associated costs plus or minus, because the time frames would be slightly longer or shorter. There'll be slightly more or less cost associated with that.

COMMISSIONER: It seems not as conservative as I might have expected with the construction of the first one, so I wonder - - -

MR GREEN: I think one of the difficulties in this is that the - you know, the real cash flow starts when the order's placed and you can do a lot of preliminary work that may seem very expensive on the assumption that you might never have a power plant, but in comparison to the actual capital cost that you're going to invest once you have a contract, it's relatively small. So the real factor is going to be that once you reach that point where a contract is set, all the preliminaries have to be in place so that the project can go forward on a schedule.

MR DOWNING: I think what the - the premise we've come with is that the - this will not be the first of a kind of the technology. The technology will have standard design - - -

COMMISSIONER: I understand that.

MR DOWNING: - - - (indistinct) there will be some plants out there already in process.

COMMISSIONER: It will be the first of a kind, yes.

MR DOWNING: In Australia.

COMMISSIONER: In Australia. I think we'll come back and have a little discussion about that. I'm not convinced about the construction time frame of that and I'd like to set a broader sensitive analysis or in time, I think. But thank you both for a very clear presentation. We will now adjourn until 10.30 when we will have an examination of analysis for radioactive waste storage and disposal facilities.

ADJOURNED [10.18 am]

RESUMED [10.29 am]

COMMISSIONER: We reconvene at 10.30 and I welcome Dr Tim Johnson from Jacobs. Mr Jacobi.

MR JACOBI: Quantitative analyses and business case for radioactive waste storage and disposal facilities in South Australia. Quantitative analyses will be undertaken to determine engineering procurement, construction and life cycle, operating and maintenance costs associated with the possible development for hypothetical types of radioactive waste management facilities in South Australia. The scenarios to be considered are surface, near surface low-level waste management facility, a tunnel blow and intermediate level waste management facility, a centralised dry cask spent fuel storage facility and a deep geological disposal facility. To provide a presentation in relation to that matter is Mr Tim Johnson of the Jacobs Engineering Group.

COMMISSIONER: Dr Johnson please proceed.

MR JOHNSON: Okay. Thank you very much. Well, I am presenting on behalf of Jacobs and the actual presentation was put together with my colleague (indistinct) Cook and our subject matter experts, NCN and Geneva. The approach that we are taking in this analysis aligns with the request for proposal which we initially responded to and we are looking at four generalised types of waste storage and disposal facilities. As identified a moment ago, these are – this is terminology we have chosen in agreement with you because internationally there’s quite a lot of disagreement about the terminology in this area. Interim storage facility for high and intermediate level wastes. This will be a surface facility. A geological disposal facility (GDF) for high-level waste and this will be a deep underground facility. An intermediate depth underground repository which will probably be co-located with the GDF and I will come on to that a bit later. For intermediate level wastes and finally a low-level waste repository (LLWR) which is a near surface facility.

Our investigation will look at the business case to manage international waste which does not have a local solution, as well as potential Australian waste from a nuclear power programme. So what types of waste are we actually considering in this study? Well, we are going to be looking at the following, and again, it’s to simplify the following of three waste streams. The first waste stream we are calling high-level waste and mostly the high-level waste is spent nuclear fuel. Potentially with some stabilised waste in the reprocessing of spent fuel. This waste we assume will be delivered in casks for eventual disposal in a deep geological disposal facility, the GDF. The second sort of waste we are looking at is the intermediate level waste, mainly from nuclear power plants, will be delivered in robust containers, again for eventual disposal in an intermediate depth repository. Finally we have low-level waste arising from Australian nuclear related activities, e.g. medical waste, packaging, clothing for disposal in a low-level waste repository. This low-level waste repository will also probably be picking up certain amounts of waste which are generated during the treatment of the high level and intermediate level waste.

So if we look at how much waste we are actually going to be managing or considering, let's look at some key assumptions. There is an existing and well-documented stockpile of high-level waste, largely it's spent fuel and it is held internationally. This is documented and this is waste which is actually in need of a permanent solution. Similarly, there is a lot of data available on the willingness to pay of customers for the management of their high and intermediate level wastes. So we look at published holding costs. We have identified some potential customer countries and the ones we have identified do not reprocess their spent fuel at the moment; that is partly because of the exclusions we are putting on to this study. We are making the – excluding waste accruing from countries which already have advanced waste management programmes, e.g. USA, some European Union countries, Russia and China. We have made the assumption that these countries will continue to store and dispose of their own wastes. Similarly, international low-level waste is excluded. It is assumed that local and national solutions predominate for the low-level waste.

How are we going to approach this? We are going to model the total amount of radioactive waste requiring management over time and this will be based on the size of current and future stockpiles for both existing nuclear power programmes and those programmes which are in the advanced stages of planning. We are going to use typical rates of high level and intermediate level waste creation for light water reactors because these are the bigger part of the market. Then we are going to estimate the percentage or the fraction of the total market which we believe South Australia will be able to capture and an upper and lower bound on this depending on market and other factors. So this should give us the quantity over time of waste which will be coming in to the country.

Let us look at the general assumptions regarding the waste storage and disposal industry. The first thing to comment on is that it is a very long timescale activity. The timeline just for licensing, developing and commissioning the facilities are long and the facilities themselves are assumed to operate for many decades. We are saying, as a working assumption, 25 plus years for development, 60 to 100 plus years for operation. Within that, we will be looking at different scenarios to establish the range of likely timescales to bring these facilities in to operation and we note, in that context, that surface storage is expected to be developed more quickly than underground disposal and as typically the value of waste or the cost of waste is transferred at the time of the responsibility transfer, the revenues will proceed the cost of the underground disposal. The other general assumption we note is that both capital and through life operational costs are significant; it is not just an upfront expenditure.

What I will do now is talk briefly on the key assumptions for each of the individual facilities under consideration. I have chosen to order these in the way that the waste tends to flow, so the first one we're talking about is the interim storage facility and this is also known internationally as the interim spent fuel storage but in this case it will cover more than just spent fuel. We are assuming a five to 10 year lead-time to operations after the siting and approvals were in place. We are saying that siting and approvals timescale is a bit uncertain but once you have got that we can start actually construction and the design and the building then we have five to 10 years. We are assuming it will be located near to a new dedicated port in South Australia. Experience elsewhere has shown that new ports are more suited to this sort of operation than trying to adapt existing ports. The facility will be close to the port and we are assuming it will be connected by a short haul road. The IFS, or see both high-level waste and intermediate level waste in specialist casks and containers for surface storage. We will size it to meet the model demands we talked about previously and we will make the assumption that construction will be modular, that we won't build the full-scale facility on day one; we will build enough for a few years and then keep ahead of ourselves by building future additions to it as time goes by. We are also making the assumption that it is in a position where it can be connected to power, water and other networks and it will have a local workforce.

We move on to the geological disposal facility. This has got the most onerous siting constraints and we expect it to be located in a region with suitable geology, hydrogeology and geochemistry to a depth of at least 500 metres for deep underground disposal. Given these constraints, it is reasonable to assume it will be located several hundred kilometres from the interim fuel storage facility. Because it requires an enormous amount, or a large amount of underground work and so on, we are estimating it will take at least 15 years time to operations after the siting and approvals were in place. We also assume that it will be connected to the interim fuel storage by a heavy railway and there are heavy railways around in the world which have a suitable (indistinct) for this. At the geological disposal facility both high-level waste and intermediate level waste will be encapsulated for permanent disposal. We are assuming here that the actual capsules which will be involved will be fabricated elsewhere and would be brought to the GDF where the encapsulation plant will be located.

Again, the facility will be sized to meet model demands. As it is several hundred kilometres from the IFS, we are making the assumption that there won't be any power and water networks there and so it will have standalone power and water supplies. This is very common of course in South Australia where you have (indistinct) mines and so on. Similarly, we have assumed that it will not have a local workforce. If we move on to the third repository which we are calling the intermediate depth repository we are making the assumption that it is co-located with the GDF. This isn't essential but there are significant operational and capital benefits in having it co-located. It will share common infrastructure and workforce with the GDF. It will take quite a long time to construct; we are estimating 10 to 15 years time to operations after siting and approvals. In the same way that high-level waste will be encapsulated, the intermediate level waste will be encapsulated for permanent disposal. And it will be sized to meet model demands.

COMMISSIONER: Tim, could I just stop you there and go back to the previous one. When you say you don’t assume a local workforce - - -

MR JOHNSON: Mm’hm.

COMMISSIONER: - - - what precisely do you mean by that?

MR JOHNSON: What we assume by that is that the facility will be in a rural or remote area and it will be a long way from anywhere and the workforce will come in either by rail or by plane or by car and will stay for a certain period of time, often called FIFO.

COMMISSIONER: Yes. Well, that – I don’t know that that is necessarily an assumption for us but now I understand what you mean.

MR JOHNSON: It was just due to the location of - - -

COMMISSIONER: Yes.

MR JOHNSON: - - - the GDF.

COMMISSIONER: Yes.

MR JOHNSON: So if we move on to the low-level waste repository, this is a surface facility. It's got fewer physical constraints on siting, ie issues of climatology, geological stability than the ILR and GDF, and indeed there are low level waste repositories operating internationally for some decades. Other countries have found how this can be done. It could be co-located with other facilities. It is not necessary but it may well be cost beneficial. For the purposes of this study, we're assuming it will be near to but not necessarily co-located with the IFS. We're assuming - and that assumption leads onto a local workforce and connections to power and water networks.

We're also assuming that it will receive compacted, sealed, low-level waste, predominantly by road - waste which will be coming from the GDF and intermediate (indistinct) facility obviously will come in by (indistinct) again sized to meet model demands. I mean, note in that context the volumes of low level waste are significantly greater than intermediate high level zones. So those assumptions were really specific assumption to the individual facilities. There are some more general assumptions which I outlined on this slide.

Initially, South Australia has large areas with suitable geology for a GDF and IDR facility, we understand without having done any detailed investigation. So we're making that assumption and we've also made the assumptions that there were a number of coastal locations which are suitable for the interim storage facility. We note and assume that all four types of facility form links in the service chain for the management of waste. It will be not very efficient, in our view, and we've assumed that all four will be done at the same time or in a coordinated program.

We are going to undertake business case modelling to incorporate (indistinct) times to establish and a legislative, regulatory siting design in other processes prior to construction and operation, and we've also noted some other specific assumptions related in particular to the (indistinct) part of the waste. The (indistinct) part of the high level waste is likely to have spent 10 years in wet storage at the source location. We're going to assume 10 years - that is a typical international number. Some waste may be released earlier than that, some rather longer. But 10 years is a good working number and that will be the time the wet storage - prior to delivery to the ISF by ship and then the last bit by truck.

This waste will still be producing quite a lot of heat and it will - we are making the assumption it will have to have 30 years storage at the ISF before it's relocated to the GDF and clearly that gives a certain amount of time to build the GDF in a phase program. The casts - the spent fuel and high level waste come in are very specialist. We are making the assumption that these will be supplied by customers. When the waste is taken up to the GDF and the intermediate depth repository, it will be taken out of those containers and they could be returned and re-used, and we've made the other assumption that the shipping cost will be met by the customers. We'll start costing from the point the waste arrives actually at the port facility and the main assumption that we made is the potential benefits and possible costs manufacturer undertaking the shipping and other support services are excluded from this analysis. We're trying to keep it a fairly clean within Australia analysis.

So those are the main assumptions we made about the various facilities and the amount of waste. Let's move on a little bit and talk about the cost estimation processes that we're undertaking. We're going to be doing our cost inputs at the Australian Association of Cost Engineers class 5, or concept level and this give an anticipated uncertainty of minus 50% to plus 100%, and this concept level is appropriate given the uncertainties regarding the design location technologies and so on. We're going to approach the assumptions for capital and operating costs in the following way: We'll consider the overseas experiences and here we'll both be looking at designs and costs of overseas projects and plan projects. From that, we'll develop South Australian equivalent costs.

We'll develop both so-called top down and bottom up costs, as a cross check. What we mean by this is a top-down cost will take an overseas facility, convert the price of that facility to South Australian equivalent costs primarily by saying how does it size compare? Does it do the same number of things? We'll take the variable cost and we'll factor it, just to make it look like the size and type of facility in South Australia. The other approach we'll do is the bottom up approach and here we'll take the design of a facility rather than its cost. We'll look at the elements of the design, the various bits of equipment, the number of kilometres of tunnel and so on, and so forth, and estimate the cost of those individual items and components, and add those up to (indistinct) process.

Our hope and expectation is that we'll get a reasonable cross check, but we're yet to find out and the other thing we'll do in the cost estimation is we'll consider exactly when those costs will be incurred and work out the phasing of the costs over time. What I can show now in the next couple of slides are some of the reference projects that we've identified and our colleagues in Geneva in particular have identified for us, for the various facilities. The GDF and intermediate depth repositories share some common features and so we've looked at international concepts that is at a high level and from these we've identified that the most appropriate concept for South Australia - and this is the one we've assumed - is a basement block concept and there are several, but we have chosen this specific following based on what concept designs for further valuation.

For geological disposal facilities we've got the Swedish Finnish KBS3H in tunnel disposal concept which has an engineered barrier adapted to the arid environment which is appropriate for (indistinct) concept and for the intermediate depth repository we've used the UK reference for disposal concept, again for (indistinct) and this disposal concept has been designed to accommodate a wide range of low to intermediate level wastes. If we look at the next slide the specific data sources, if anybody's interested, are available and these you'll notice are at different periods. They range from 2005 for the finished cost estimate and the most recent Swedish one is 2013, so it is very near to current.

We would also note that we are taking advantage of a slight further studies here, but as well as the basement rock concept we will look at some of the surface infrastructure costings coming out of a high isolation concept study in Switzerland, but that's only for the above surface or surface infrastructure. When it comes onto reference projects for the (indistinct) storage facility, again there are quite a few of these facilities worldwide and there are quite a few different (indistinct) types of cast and so on. We've reviewed the variants and we've identified a working assumption, but we'll assume the Holtech system - so that's the casts, the lifting equipment and so on will be brought in as that system.

From a design perspective, we've looked at a private fuel storage project in the USA. We've looked at a more comprehensive Electric Power Source Institute of USA study in 2009 and the United States Department of Energy study in 2013. So we have a reasonable amount of data there and the costs will come from those studies, and also from International Atomic Energy Association costing of spent nuclear fuel storage report, again from 2009. So what sort of cost factors do we bring in to the analysis? The first major cost factor is location-related costs. We recognise that the interim storage facility and the low-level waste facility will be moderately closer to existing infrastructure whilst there will be very little or no infrastructure at the location of the GDF and interim depth facility. So we're looking at location-related costs.

We're looking at costs of escalation. We've noted that the previous studies are a number of years old and we all use building price index increases and so on to factor those.

We'll look at the scale factors compared with the overseas facilities in both the top down and the bottom up cases, and we'll look at the other costs, particularly upfront costs and ongoing phase expansion costs, and we'll look at the sequences of facility planning construction operations, mid-life renewal and eventual decommission.

In addition to these facilities where you can almost envisage them as having a fence around them, you have a lot of enabling infrastructure and we've identified the enabling infrastructure in two different categories; hard infrastructure. This is airport facilities and we've identified that there'll most certainly be a need for an airport immediately at the GDF and we've identified the need for a new port adjacent to the interim storage facility. There'll be (indistinct) road connections between these facilities and there'll be water and (indistinct) connections, and or stand-alone systems for the various utilities - and I just mentioned the two most important ones there. As the GVS site is some way away from existing infrastructure we'll need to consider accommodation at that site. In addition we see there's a fair bit of agency or human infrastructure. We need to develop the legislative basis for the industry and we need the expansion of regulatory bodies and there will be a lot of corporate interdepartmental works. We are going to put cost estimates against both (indistinct) and agency of human infrastructure costs.

Other foreseeable costs – and this is a shopping list that isn't complete but it takes you down further into the depth of the costing. There will be costing associated with site selection and agreement and we've identified from international experience that that could be quite a large number. Then there's the evaluation and environmental impact analysis. This selection and agreement not only includes the site, it includes the transport corridors. Once the site has been identified and costs have been put against identifying the sites, there will be both concept and detailed design, land acquisition and use costs, again both for sites and transport corridors.

We will put assumptions in for costs of (indistinct) logistics because although we have assumed that the customers will pay for the shipping, we've assumed that any logistic movement of the waste once it arrives in Australia will be part of the costing. There's costs for facilities maintenance. We identify significant costing which will assume the regulatory licensing and inspection costs. Then there are post-closure activities. The post-closure activities obviously will be site specific. In addition to that we have the direct workforce costs, site admin operations, quality assurance, security, et cetera.

At this stage if we follow those two specific work streams, one looking at the demand and another one looking at the cost estimates, then we have got two sets of data which we'll use to form the bases of the commercial modelling. We will identify initially the revenue requirements to meet various rates of return, calculated at a range of discount rates. Once we identify those revenue requirements we can compare those requirements with the published knowledge of customer range of willingness to pay values. So we can check how the two compare.

We'll consider generic scenario analyses. Some of these are mentioned in the slide, including time to gain licences, the size of the facility, the speed of implementation, the distance away from the interim disposal facility, where the GDF is located, hence the length of railway, the phasing of construction, the size of demand and the phasing of demand, et cetera. So the model will be set up so we can do a large number of scenarios in a fairly efficient manner.

We note also that there are linkages with other work streams that have been commissioned by this Commission and we note that a South Australian waste management capability would address the waste requirements from a nuclear power plant which will need some access to GDF and obviously a linkage with the fuel manufacture and enrichment stream. Through our work and ongoing work we'll liaise with the other consultants through the Commission to make sure we take note of these linkages.

So from this work what are the outputs that we envisage? We envisage cost ranges with assumptions and evidence for the four types of facility and its supporting infrastructure. We'll look at scenarios for individual or joint operation. We mentioned earlier joint operation effectively of the geological disposal facility and the interim depth repository. We'll look at opportunities for phase development. We will identify revenue estimates with assumptions and evidence and we'll derive commercial outcome measures, including internal rates of return, net present value and so on at various discount rates. Most importantly, we'll undertake a sensitivity analysis to address key areas of uncertainty and demonstrate overall confidence in the findings. That is it, thank you.

COMMISSIONER: Thanks, Dr Johnson. I don't think we've got any questions. We'll adjourn till 11.15 when we'll look at analysis of electricity generation from nuclear fuels.

ADJOURNED **[10.54 am]**

RESUMED **[11.14 am]**

COMMISSIONER: Good morning, we reconvene at 11.15 with analysis of electricity generation from nuclear fuels and I welcome Mr Robert Riebolge and Mr David Lenton. Mr Jacobi.

MR JACOBI: Quantitative viability analyses of electricity generation from nuclear fuels. Quantitative viability analyses will be undertaken to assist the economic viability of integrated nuclear power generation technologies in to the suite of renewable and fossil fuel technologies that are likely to supply the national electricity market during the years of 2030 and 2050. To that end, explaining that analyses are Mr Robert Riebolge and Mr David Lenton.

COMMISSIONER: Mr Riebolge please start.

MR LENTON: Thank you. (indistinct) take you to describe (indistinct) our approach. So this morning’s agenda breaks down in to four areas, two slides or (indistinct) objectives and (indistinct) approach. My colleague Robert – we are just going to run through our approach to forecasts in South Australian demand and the (indistinct) mix in South Australia. We have then got a review of the economic model, the (indistinct) principles that have been applied and the cost and benefits of being assessed and then our approach doing sensitivity and Monte Carlo analysis. I put this break down as following, first is to quantify the economic viability of a nuclear generator being commissioned in South Australia in either of the years 2030 or 2050. So we are looking at two entry points. In either of those situations, the construction and the pre-construction activities would need to take place several years earlier if the plant is to Commission on those dates. To try and make it a realistic assessment we are comparing four separate alternatives. One being small nuclear, the second being a large nuclear plant but we are also considering more conventional plants such as CCGT and also a CCGT with carbon capture and storage.

We will consider the viability against a range of scenarios for demand in terms of how demand growth may rise over the next 10 years and if we go to 2050 the next 35 years and also a range of mixes of renewable generation. The model allows you to test a variety of different options that could emerge. Finally, we are producing a flexible and transparent model that allows the user to modify many of the assumptions and the inputs themselves and consider what impact that has on the relative MPVs of the four options. The net present value is basically a summation of the present value costs and benefits of the different options, a really good way of comparing the four options.

MR JACOBI: Just before we move on, perhaps you could just explain what CCGT is?

MR LENTON: Okay. CCGT is a combined cycle gas turbine plant which is one of the more efficient gas turbine plants that exist at the moment. So our approach breaks down in to the following steps. First is an assessment and projection of demand for South Australia and that will be built up from a number of historic demands, that's broken down in to discreet elements and my colleague Robert will say a bit more about that in a minute. We will then forecast the amount of renewable generation in South Australia, building it up with projections of PV, of wind, of storage and of solar thermal technologies. Using those two inputs we can then calculate the output that may be required from South Australian generators and the potential to send energy over the interconnector, with a range of interconnectable (indistinct) that can be applied. Moving on to the economic models then we applied some generator assumptions around fuel costs and how they may operate, to determine the costs and benefits of the different options and then run some Monte Carlo analysis to assess the sensitivity of the results.

The model runs as an integrated model, so changing any of the demand renewable assumptions right at the top of the model, will flow through and impact the MPV of the different generation options that we are considering. I am going to hand over now to my colleague Robert Riebolge and ask him to talk through the demand and renewable.

MR RIEBOLGE: Thank you Dave. We have been fortunate to have historic data sets of half-hourly intervals from the South Australian grid and these have been provided courtesy of SA Power Networks. They disaggregated in terms of demand by a major customer category, business category, residential category and hot water load and renewables, photovoltaics and wind generation. Here is an example of a data set for the business category with the settlement day on the left hand column, settlement hour – half hour sorry, next to the settlement date and across the top is the months and then the entries, the measured entries are in the table there as an example of half hourly data. The importance of half-hourly data is that we can measure characteristics of different consumer categories in terms of peak load values and durations. We can identify temporal and seasonal variations. We can identify characteristics of consumers by disaggregated business and residential. The finer half-hour granularity means that load shapes more closely mimic the real-time load shapes which gives greater confidence in terms of forecasting load shapes and leads to statistically more credible forecasts.

Here we see a residential load shape mapped against the background of a system demand and we can see for the load to normal demand month on the top slide there's not a great degree of variability. However, on the bottom side we see that there are significant peaks which we can pick up with this finer granularity. Those peaks basically are driven by the residential demand and the air-conditioning load on a period of hot days. You can see that trend upwards to the maximum on the lower side. For business, however, we don't have that seasonal variation but what we do have is a temporal variation. You can pick out five peaks during the weekdays and on weekends it falls away to virtually nothing. It is simply that underlying base load for the business category.

With photovoltaics takes are mapped against the background of the system requirements. We can see that they are fairly small at the moment. We can't quite see the seasonal variation but we'll see that in a couple of slides to come. Wind, on the other hand, is getting close to meeting almost the entire system requirements on a normal to low-demand day. Peak-demand day it falls away somewhat. There's a fair amount of deficit there to be made up. This is an interesting slide. It shows the fossil fuel generation in the South Australian grid with intermittent renewables. We can see that there's hardly any base load there. Consequently, to have fossil fuel plants operating in base-load mode they have to take advantage of the interconnector which connects the South Australian system into the National Electricity Market which includes Tasmania, Victoria, New South Wales and Queensland.

Now we're going to zoom down on particular days, a maximum-demand day and a normal minimum-demand day. They're the system requirements. Here we have the components that make up those system requirements. At the bottom is the major customer load, almost flat. Next comes the hot water load which contributes to a mini spike, a mini peak. Then we have the business load which is significant in terms of the total system demand. The residential load makes up the entire system requirements and we can see the peaking impact of residential load in a summer month.

Here we have a slide which shows the variability of photovoltaics at the top. We can see that during summer fairly constant sunshine, during winter cloudy cover and the demand falls away and is variable. It's only half the production of the summer month. The bottom slide is winter. We can't really detect any seasonal variation there. All we can say is that there's variability across the day. This is mapped out at period of months and again we can see the seasonal variability of photovoltaics but not so much in terms of wind. It's just an intermittent supply.

Here we zoom into the historical generation which is meeting the South Australian system requirements and these are photovoltaics. At the moment not much in terms of total system requirement but is increasing very rapidly. However, wind is a significant contributor and you can see in the top slide there that between wind and photovoltaics they make up about 40 per cent of the total system requirements. Bottom slide, a significant amount of deficit to be made up. That is made up with fossil fuels at the moment and we can see that in the beige-coloured area.

In terms of the system model we're forecasting an example here to the time horizon of 2030. We need to forecast out the categories of demand that we have already which are business, residential, major customer and hot water load but we have two further categories that forecast out to 2030 and that is cogeneration and electric vehicles. The four categories of cogeneration, we can set values at high, low or medium. Cogeneration can be set on or off and electric vehicles can be set as a percentage of the total vehicle population in the 2030 time horizon.

MR JACOBI: Could I just stop you there. Could you just explain a little about what high, low and medium might mean in the context of those categories?

MR RIEBOLGE: Just about to do that. We can see here the example of inputs to the demand model in 2030. The high, low and medium values select a growth factor or an application factor, parameter factor. In the case of business we've selected medium, 1.2 per cent growth per annum. Residential, medium, 1.5 per cent growth per annum. Major customers, medium again, .2 per cent growth per annum. Hot water load is a regression of minus .2 per cent per annum. Cogeneration we've set to off and electric vehicle market we have set to 25 per cent of the vehicle operation in 2030.

Having inserted those into the model, the model generates these load shapes, the system requirement, on a low to medium day at the top and a high demand day at the bottom. We can see that the major customer load forecast of 2030 is still a very small component, flat, of the total system requirement. Hot water loads still contributes to some mini peaks but not a significant part of the system requirements. Business, of course, makes up a substantial amount, as it did in the historic slides that we had a look at just before. Of course, residential continues to contribute to that peak. However, we have another load here and that is electric vehicles. Interestingly, electric vehicle demand makes a significant contribution in a low demand day but in a high demand day it exacerbates the peak, which has to be dealt with.

Now, we have to imagine ourselves in 2030 with what sort of technologies are going to be available to us. The models identify the number of technologies. One is the penetration of PV in the business sector. The other is PVP with storage which are basically batteries. There'll be batteries in the home or in the residence. Wind paired with storage. This would be grid storage, wind-installed capacity, solar thermal plant, nuclear plant, interconnector constraints and vehicle to grid penetration. Vehicle to grid is simply a mechanism which enables the grid to tap into the energy store in power batteries. Again, we have variables that we'll go through in a moment that we can allocate to the model.

In this case we have allocated a variable of medium penetration for business categories which is 30 per cent, penetration in the residential sector is saturated, PV paired with storage high we've selected at 80 per cent, wind generation paired with storage we've selected at high of 60 per cent, store capacity of wind 2000 megawatts, SDP, medium at 200 megawatts, interconnector constraint medium at 650 megawatts and vehicle to grid penetration at 40 per cent. The technology parameters for PV and wind generation are either the historic data sets and for the others simply the installed capacities which determine the power that is generated. This reminds of us of the system requirements but in these sequence of slides we will have a look at how the generation meets the system requirements. PV on its own is still making a minor contribution but a contribution to the system requirements. But next we have PV generation paired with storage and what we see here is that in this instance the generation is flowing right throughout the day, not just for a period of the day. It also assumes future knowledge of the system demand which we all know in a probabilistic world is an impossibility. However with the distribution of distributed generation throughout the smart grid which is happening with photovoltaics and photovoltaics paired with storage and the advent of big data which we have alluded to, it is very likely that by 2030 mathematical algorithms will have been written which can predict fairly closely the demand curve. Consequently this is a fairly good approximation of what will happen in terms of the rules for releasing from storage.

Here we have wind on its own, not much we can do about that, simply goes in to the system to meet the system requirements and here we have wind paired with grid storage which releases the wind in a rule similar to what photovoltaics paired with storage does. We then have vehicle to grid which is very small amount but then the population that we have assumed is small and as the population of electric vehicles increases, this will increase as well. Here we have the solar thermal plant which generates at its installed capacity and we can see on the top slide that renewables have made up almost the entire system requirements. On the bottom slide, there is still a significant gap to be met. This is nuclear generation which satisfies all of the requirements on a medium to low demand day and is significant the amount of generation on a high demand day. The remainder is met by fossil fuels that are in the system at 2030.

In terms of exports, quite clearly on a low demand day, we have substantial amount of surplus power and we can make use of the interconnector which I have alluded to just previously to transfer surplus power in to the NEM. The model generates this profile for the export, for the example that we are looking at and we can see that the first renewable to be exported is just a small bit of wind paired with storage followed by a small bit of vehicle to grid and a reasonable amount of solar thermal plant. The remainder however is nuclear plant which is being dispatched after all other renewables have been dispatched. However, we are limited in terms of the amount that we can export by the interconnector constraint. Consequently, we have one or two options, well we have two options, one is to remove some of the constraints or relax some of the constraints of the interconnector or alternatively if we look back at this slide here to insist that the nuclear plant is dispatched ahead of some of the other renewables. The model then is able to do all of those things and it populates this table with information which is needed for the amount of energy sent out in the South Australian grid and the NEM. In the different dispatch modes for the different types of plant under consideration, including CCGT, small nuclear, large nuclear and CCGT with CCS. This is input to the economic model which David then works on.

MR JACOBI: Perhaps before we go to Mr Lenton, I just – perhaps if we could just clarify that you have shown us a series of slides that I assume are based upon a series of assumed technological inputs and technologies within the network and that they are examples. Is that right?

MR RIEBOLGE: That’s right. That’s correct. Yes, they are all examples and they can be varied at the user’s discretion.

MR LENTON: The economic model then builds on the information that will come from the demands and generation scenarios and it is worth just recapping on a couple of high-level principles. The first is that we are focussing on the commercial viability of a nuclear generator or a gas fired generator in 2030 or 2050 but we are looking only at the viability for that specific generator. We are not looking more widely at societal benefits or some of the jobs that may be created or some of the other (indistinct) that are not captured by the market place. We have assumed that the value of carbon will be captured through some form of carbon price. It is fairly uncertain at the moment exactly how carbon will be priced in the future, so we have applied a proxy which is a form of carbon price but within the model we do allow the user to select different carbon price options which can materially affect the results. The user can also select a number of other inputs that will affect the generation requirements from any of these plants and that includes the amount of renewable generation, the demand scenarios, the dispatch mode that Robert has just mentioned and also the level of (indistinct) availability that may be assumed from the different options.

So the model breaks down in to a number of different costs and benefits that were assessed and I have got one slide on each of these coming up in a minute. But on the major cost side we have got six main elements, we have got the capital cost from the construction of the plant, we have got the variable fixed operating and maintenance costs during the life of the plants. We have got fuel costs and carbon costs for the different options, decommissioning costs for – particularly for the nuclear options and then connection and network upgrade costs where these are required. Then benefits divide up in to two areas, firstly there will be sales of electricity in to the South Australian market and then sales of electricity via the interconnector in to the NEM. So the first and the most significant cost, particularly for the nuclear options is the capital costs of plant and this has been built up from overnight in dollars per kilowatt capital cost that are being supplied by some of the other advisers that have been employed by the Commission. We have taken these inputs and we've taken a profile of those costs and we applied interest during calculations and for the nuclear option we have also taken appropriate exchange rates to come up with a cost that go in to our economic model.

The model has been set up to allow different discount rates to apply separately for all generation options to reflect the different levels of risk that may be applied for the different technologies although we are still working with the Commission to decide what discount rates should be applied for the different options. And the model will also include the option for the user to assess the impacts of scenarios around budget overruns or delays in project completion. At the central value is that (indistinct) they can be varied to understand what impact that may have on the relative (indistinct) of the solutions. So the next element of cost is the operation and maintenance costs. On the fixed side, the fixed maintenance costs are almost all the nuclear costs have been assigned to this bucket and it breaks down for the nuclear stations in to insurance costs which have been separately split out, costs for overseas work which has been captured in US dollars and then local work that is required to maintain the plant. We have also got fixed costs for the local plant as well. The variable costs are far more significant for the gas-fired plants where some of the maintenance costs are based on running hours and therefore as running hours are incurred, the variable costs (indistinct) incur that way.

One thing that is different about these costs to some of the other costs is that they escalate in real terms over the course of the model, so the percentage at which they increase is greater than CPI and therefore an escalation factor has been built in to the model for these costs. Fuel costs have obviously been included within the model for the nuclear costs, so being providers and dollars per megawatt hour sent out option and they include the cost of enrichment as fabrication as well as the cost of fuel itself. They have been provided in US dollars so the model will convert back to Australian Dollars in its comparison, and clearly the exchange rate used will impact the working viability.

Gas prices are going to be provided as a gas price trap with full prices of gas prices over the lifetime of the model. Gas prices have changed a little bit recently where there's been some significant movements, but this is a long term price production that we've produced by one of the Commission's adviser. It means that a very significant amount of the total cost for either of the two gas part options and that total cost is obviously reflective of both the actual price of gas, but also the assumed efficiency of the gas plants, and one of the expectations within the modelling is that both gas plants improve their efficiency between now and 2028 when they'd need to start being built, and again that's based on the advice of other advisers that have been appointed by the Commission.

Carbon costs have been included within the model and for the CCG2 part they're based on calculation of the tonnes of CO2 that were emitted, and the carbon price that is assumed to apply, and that's been calculated again separately by an adviser to the Commission, but it's going to be based on the 450 parts per million target, but there will be options with the modelling to consider other targets for carbon reduction and what that does to the carbon price.

For the CCCG2 with carbon capsule storage there's a cost for carbon preservation and transportation, so for storing the carbon and a carbon capsule - carbon cost for the uncaptured percentage of emissions, typically the CCS will economically capture around about 85% of emissions with the remaining emissions still needing to attract some carbon price. The model assumed that there were no carbon costs association with nuclear fuel, so it's ignored any carbon costs that may be associated with fuel mining and decommissioning cycles, but that is consistent with how we've treated other fuels within our analysis.

We would also be separately calculating the total carbon amelioration benefits from the four options, although that won't feed into the MPV analysis, that will just be provided as separate information in terms of what the tonnes of CO2 saved from the various options may be. Connection costs will be included for all plants. These are reasonably small in comparison to some of the other costs that we've seen. We also have infrastructure costs for each option which could be road and (indistinct) upgrades that might be needed for some of the plants.

For the large plant option we've also included an assumption that a transmission inter-connector upgrade will be required, that will run all the way from Victoria through to South Australia. But we do have an option to determine what level of contribution from the large nuclear plant should be made for this upgrade. This upgrade will obviously be useful for the large nuclear plant, but it could also be useful for other renewables within South Australia, because they would be able to export a large amount of time if the inter-connector was upgraded.

The final cost line is on decommissioning costs. These are costs (indistinct) plant will apply at the end of the plant life and we've been provided with estimates of these costs, and we'll be applying an escalation factor which is assumed to apply to the end of the model. We've also included separately cost estimates for dry storage, which is based on a dollars per megawatt hour levy expected to cover the cost of the facility. There will also be costs for wet storage, but they've been covered within the fixed operation and maintenance costs that we mentioned earlier.

Some (indistinct) costs is going to depend on the expected cost, the life of the plant and the assumed discount rate. The higher the discount rate, the longer the life of the plant (indistinct) appear smaller in their present value terms. For completeness, we have also included retirement costs for the gas plants, but these are relatively low in materiality, in the scheme of things. So on electricity sales - these have been split between sales in South Australia and sales across the inter-connector to the rest of the (indistinct) and we've made adjustments for the margin or loss factors that will need to apply in both of those instances.

Robert's already mentioned that the model can test different levels of inter-connector capacity and we'll also be applying differential prices which should arise out of the market modelling results, and put those into our modelling. Just one slide there and up on the data sources that we have used within the model. They've all come from recognised sources and one thing that I want to be stating is that within our model we will be carefully lifting each data source for each input so it's very clear how everything has been devised, and if people disagree with it that's their right, but it should be clear how the model's been put together and where that information's been derived from.

I've got three slides to wrap up on sensitivity and Monte Carlo analyses, and I'll try and be reasonably brief - I know we're towards the end of our time. So I guess the first - it's just a question why do we need sensitivity analysis? I guess there's a lot of uncertainty in this MPV modelling because we're looking at plants that won't start for 15 years or 35 years, and then will run for up to 60 years after that point. So we've got a lot of uncertainty around a number of the variables, and therefore what we've done is to create a most likely value and then a high or a low value to assess what the impact will be if the high or low value were to apply in the model, and we've selected a number of variables that are picked up here.

We've got fuel cost variations, we've got parameters that relate to the initial capital cost - that will be the overnight cost, the discount rate, et cetera - the efficiency of the plant, the variations in wholesaling carbon prices, the operations and maintenance costs and for the nuclear option, the exchange rates where a number of the costs have been applied in US dollars, and this range of likely values is tested in a tornado diagram and a Monte Carlo analysis, and I've got one example slide of both of these coming up.

One thing I do want to stress is that these examples are based on illustrative data, they're not based on the final set of datas. They're provided as an example, so users can understand the sorts of outputs a model will produce but these aren't final data. So this is an example of a typical analysis for the MPV of the CCG2 plant. The central line shows the most likely prediction and then the bars either side indicate the impact of each individual variable applying separately from the other end of the high and low extremes. So the first example is the variation in the wholesale price with the carbon element taken out - could increase the MPV if it was 10% higher by looking at those two bars, $200 million - the bars each represent $100 million movement.

So we can see that some of these variables are highly important in terms of the MPV. Obviously the options - and the sort of things that are showing up high up on the list for the combined (indistinct) gas turbine plant and the wholesale price, the efficiency of the plant - but obviously that will impact how much gas is used - and the percentage change in the gas prices, the gas prices different from what we predicted then clearly that will impact on the viability of the plant.

So my final slide is just to give an example of the Monte Carlo analysis that will be produced by the model and this is applied using an Excel add on from Oracle called Crystal Ball, but there are many other similar tools that can also be applied - and what it does is it enables you to vary all the key parameters according to a defined distribution and provides the range of possible results by doing a large number of trials. This particular option we see, that the trial's ended up with a mean of minus $100 million, but a fairly large range that goes from positive $260 million to minus $460 million. So a reasonably large range of outputs with 30%, be it above zero and the aim within the model is obviously to understand the range of results, but also to find - come up with a reasonably tight range for the key parameters, so that the overall range that you get from your simulated model gives you some certainty around the expected number that will be derived from the model.

COMMISSIONER: Gentlemen, thank you very much. We'll adjourn to 1200 when we'll regroup to discuss the general equilibrium modelling assessments.

ADJOURNED **[11.50 am]**

RESUMED **[12.06 pm]**

COMMISSIONER: Welcome back. I apologise for the delay. There were some technical problems. I welcome Ernst and Young for the computational general equilibrium model assessment briefing. Mr Jacobi.

MR JACOBI: Computational general equilibrium modelling assessments will be undertaken to determine the economy-wide effects of labour, capital and primary resource flows, both interstate and intrastate, which would result from a possible investment in any part of the nuclear fuel cycle in South Australia. To explain those assessments, Mr Craig Mickle and Dr Jyothi Gali.

COMMISSIONER: Welcome. Please start.

MR MICKLE: So we're going to quickly run through just the objectives of the CGE analysis work that we've been asked to undertake, provide a high-level description of the model and the approach that has been undertaken that underpins that work, talk about the scenarios that we've been asked to use to look at different potential outcomes in respect of investment in different parts of the nuclear fuel cycle, discuss quickly some of the key inputs and the key assumptions that underpin the modelling approach we're developing as we speak and then, most importantly, obviously talk to you about some of what the key outputs will likely be in terms of the variables that we'll be able to comment on which will complete the brief as you outlined.

So obviously the key task here from our part of this job is to assess the potential economic merits for the South Australian economy of greater involvement in any part of the nuclear fuel cycle. I think you've heard a few parties talk about the business cases this morning. They covered the three elements of the fuel cycle we're not involved in Australia as it stands today but our work will also cover, obviously, the mining and extraction part of the fuel cycle. Really, what it's about is what does it mean for GDP, employment, jobs, investment, particularly in South Australia but ultimately for the whole Australian economy if indeed we were to move into other parts of the fuel cycle or expand our involvement in the mining and extracting sector.

Really it's about determining those key outputs that you've referred to previously and looking at the in-train state flows. This is just a really simple schematic of how the CGE modelling fits – not very simple, I imagine – into the process. So on the right-hand side we have our little graphic of the nuclear fuel cycle which I'm sure you are very well across as we speak, probably in more detail than we are, which really describes, obviously, the four key stages although there's more diagrams in those boxes, the four key stages of the fuel cycle that we're particularly interested in looking at from the terms of this analysis right the way through from mining and extraction to waste disposal and storage, ultimately.

In between the scenarios that we'll be adopting we're looking at those fuel cycle business cases and saying, well, what are the underpinning scenarios that may or may not drive further investment in each case. Obviously there's a BIS, which is a business as usual, and then there's two alternative scenarios which will have different assumptions in respect of the level of market involvement and/or government support that might assist in various parts of the fuel cycle, investment in various parts of the fuel cycle. At the bottom of the diagram is our electricity market model and essentially that will feed in to the work we do in two important respects. Obviously electricity prices are an important part of the fuel cycle generally and an important part of CG analysis generally but in particular, that work will feed in to the nuclear generation business case that you are talking about because clearly one of the things that an investment in nuclear generation will impact is Australian electricity prices. Those then flow through in to the model.

And on the left hand side is a very high-level schematic of how the CG modelling works. Now in essence, computer (indistinct) model really does two things that typical more narrow modelling doesn’t do, it’s dynamic and it takes in to account substitution effect. So what I mean by that is that the model is set up in such a way that if we see further investment in one part of the fuel cycle, in the nuclear fuel cycle, let’s assume it’s mining for the sake of argument, that by definition affects other parts – the factors of production in the economy generally. So enough resources, labour and capital are taking you to the nuclear sector then by definition some less resources or higher prices for the remaining resources may be required to provide those resources in another sector. What CG modelling does is an economy wide look at that to say if indeed more resources are taken in to nuclear as opposed to something else, there will be some counter balancing impacts on the economy. And the purposes of CG modelling is to take into account all those counter balancing factors and then produce an outcome that says, okay in total what does this mean for – in the case of South Australia, GDP growth and what have you.

So it’s really an economy wide view of what we’ll be testing in each of those scenarios in terms of what's happening in a nuclear fuel cycle in particular. So that is it in essence what it seeks to do and so that you can get confidence that when – if a particular policy initiative is embraced, you will have some confidence of what it will mean for the economy as a whole and what it will certainly mean for parts of the economy in South Australia like regional for example if mining activity occurred in a certain region, it would be able to pick that up and illustrate what that might mean. So that's just at a very high level. Jyothi's going to then take you through a little bit more detail in relation to how the CG modelling will work and the inputs and outputs it will use.

MS GALI: Thank you, Craig. The conception framework is a good interaction to our methodology of assessing the cost (indistinct) of the nuclear fuel cycle activities in South Australia. As part of our approach we have used – we have been using the Victoria University regional general equilibrium model. There are a number of general equilibrium model exist and available for the policy analysis but clearly we chose this model because it has a number of advantages and most suitable to this project focuses. But clearly this is widely documented and it has a very recent database and it has a more than 80 sectors and also the energy accounts and emission accounts are well articulated in this particular CG model. This model is (indistinct) the Victoria University model by centre of (indistinct) Victoria University and this model has been used by the commonwealth government departments, particularly the productivity Commission and also the commonwealth treasury. It is also widely used by the state governments and also the private sector but clearly for the tax policy issues, economic contribution impact (indistinct) and also due diligence reports for the private commercial purposes.

As I said – as Greg said, it is a dynamic model implying that construction and operation activities of nuclear fuel cycle activities can be tracked on annual basis. The model has a very specific state (indistinct) economic information in terms of the South Australian industries, structures and labour market. So for example, the model can show what is the economic impact of expansion of the Olympic Dam on the South Australian jobs and also the incomes. Not only we have used computer general equilibrium model but also by taking in to advantage of having (indistinct) electricity model we (indistinct) the general equilibrium model with the EY electricity model. EY has a considerable experience in powered market modelling over number of 20 years. It provided a number of energy policy issues to the Australian government and also the private clients. And particularly in this exercise, electricity model plays an important role in terms of the competitiveness of the nuclear powered generation in the energy mix in Australian energy market.

This model previously known as the (indistinct) model, it provides the future evolution of the structure of the supply side of the electricity market and based on the dynamic programming (indistinct) cost optimisation approach, what it basically means, given the fuel technologies fuel cost, given demand how the technology shapes in the electricity market changes. So we created this model with the general equilibrium model to get the demand and supply balances so that they are in equilibrium condition in the long run. In terms of the iteration process, the iteration starts with the CG model. CG model based on the macro economic and demographic assumptions produces electricity demand by fuel (indistinct) by end users in the economy, complete by states and industries. But a given demand, the electricity model produces the optimum combination of technologies and also resource cost and prices for sale and retail electricity prices. But in turn, those outputs produced by the (indistinct) model is (indistinct) input in to the CG model. We iterate few times to get the equilibrium achieved between these two models. Because the CG model do not have the supply side details, very details supply side aspects, that is one of the reason we are using two models to get the optimum solution for this study.

To summarise, our computational general equilibrium modelling assessment of nuclear fuel cycle activities in South Australia consists of two main parts. The first part is about changing the methodology and model calibration to suit the purpose and the second one is (indistinct) scenarios. As a complete nuclear fuel cycle activity does not currently exist in Australia, we need first to modify the model to suit this particular purpose. This involves a degree of data sources, calibration of the model parameters and also taking the information from the business cases. The second part is developing scenarios. The Commission has requested three core scenarios to assess, the economy by (indistinct) in any part of the nuclear fuel cycle on intra and interstate flows of labour, capital, primary resources. Scenario one is a business as usual on base line investment scenario which is mainly characterised by no policy shift, leading to low investment in any new parts of the nuclear fuel cycle in South Australia. The investment scenario two or IS2 is characterised by nuclear fuel cycle business cases that could be possibly driven by the market with commercial opportunities in the expansion of the new parts of the nuclear fuel cycle in South Australia. Investment scenario three or IS3 is mainly characterised by some form of the public subsidies or private capital on any part of the nuclear fuel cycle, including expansion of the uranium exploration, mining and also for the (indistinct) of the (indistinct) higher value and commodities.

For modelling perspective it is important to (indistinct) which key features of these scenarios to assess the economic impact of each scenario relate to the base line. The model (indistinct) series 2009 and 10 include (indistinct) with tables of the Australian economy. Simulation of the base line investment scenario is between 2010 and 2050. All the variables coming from this model are represented 2014, 15 prices. The simulation for two investment scenarios starts with the 2016-17 financial year and ends with the year of 2040-50 financial year. Those are the nuclear activities in the nuclear fuel cycle goes beyond 2050. As I said before, all these three scenarios require very detailed inputs but the business investment scenario resourced all the inputs from the official projections, consistent with the official growth path of the state economies and also the national economy. Under the featured listing which is three scenarios is the potential activities undertaken in each scenario. Say, for example, in the business investment scenario there is a possibility that existing uranium extraction and mining activities continually operate in Australia, may benefit from the global expansion of the nuclear sector.

In the investment scenario there is a possibility that the market potential exists for waste disposal in South Australia. This has to be determined based on the business case for waste disposal commissioned for this study and also the removing of some barriers also helps the market. In the investment scenario three potential opportunities will be considered for all parts of the nuclear fuel cycle both front and back end nuclear fuel cycle activities from uranium exploration, mining, conversion, fabrication, enrichment and nuclear power generation and nuclear waste disposal.

To continue on characteristics of scenarios, global climate change is very high on the agenda of many government policymakers. A number of governments made commitments to curb greenhouse emissions and submitted their pledges to Paris 2015. As you already know, the energy sector, the major source of greenhouse gas emissions, has a key role to play in alleviating the risk of global warming. To model the potential cost and benefits of nuclear fuel cycle activities in South Australia, in all three scenarios we have assumed stringent global mitigation policy measures consistent with the atmospheric targets of stabilising the concentration of greenhouse gases at 450 parts per million carbon dioxide emissions by 2100.

In the baseline scenario we have assumed the global economy will act to mitigate the greenhouse gases, consistent with the Paris commitments. There is no explicit carbon price in the Australian economy. For the two investment scenarios there will be a carbon price in the Australian economy. It is also important to consider Australia's role in burden sharing of the global climate change mitigation task. For the purpose of this study, based on the discussions with the Commission, slightly (indistinct) burden sharing rules are assumed for the investment scenario two and a more aggressive level of burden sharing rules are assumed for investment scenario three. These differences in the burden sharing rules allow the Australian (indistinct) to source more emission permits either from overseas or use the domestic mitigation technologies to curb the emissions domestically.

The assumed carbon price underlining these scenarios will be sourced from the published sources, mainly from the Commonwealth government, and it will adjusted to take into consideration the current global traded market, that is European Union Market. To develop these scenarios requires detailed information and inputs from various sources. The baseline investment scenario in developing the growth path of the Australian economy and South Australian economy, we sourced the inputs from the published sources, mainly from the South Australian treasury, Commonwealth treasury and Intergenerational Report. The framework we have used is similar to the Intergenerational Report, the IGR report, that is the population, productivity and participation approach. Because the model is based on state economies we need to develop this three-piece approach for each (indistinct) state.

The productivity participation and population framework approach gives us the statistic growth path of the economy in the business investment scenario. Only the difference in the scenario is the world countries have policies to mitigate the pollution but not Australia. That is the baseline under which we are going to assess the investment scenarios two and three.

For the investment scenarios the major inputs are mainly sourced from the business cases. Business cases provide the inputs, both operational expenditure and capital expenditure, on an annual basis in very detailed labour, capital and intermittent inputs and energy use. We take those inputs and in the model we construct the production and concentration functions for these three nuclear fuel cycle activities. These three new industries are not existing at the moment in the economy. We need to create in the economy based on the business case studies.

After considering all the inputs and development scenarios the model gives us a number of key outputs, both in the baseline investment scenario and policy investment scenarios. The outputs include around two or four thousand very small variables from price variables to the macro aggregates. In terms of this presentation we have provided key macro variables in terms of the extenuating parts currently on balance and gross national income, gross domestic product and labour market, including the employment, real wages and industry variables, industry gross value-added, industry turnover and investment, exports, imports and tax receipts and the contribution of the electricity sector and also the emissions by user.

At the end the key outcomes from this study is quantification of both micro and macro economic benefits of investing in parts of the nuclear fuel cycle in South Australia measured as deviations from the baseline investment scenario. These deviations either could be positive or could be negative, depending upon how the resources are reallocated in the economy because of this investment. Thank you.

COMMISSIONER: Any questions? I have one. We've heard this morning of modelling supply and demand in the electricity market and we've also heard that you're going to use your electricity model. That's a price model?

MR MICKLE: That's right. Well, there's two components. There's what's called a planning model that looks forward and says, given the cost structures in different parts of generation, what are the least cost additions to the fuel mix. So there's two components. That's the first component. So it comes up with a view about the future generation mix and then there's an optimisation model that actually produces both very short-term and long-term forecasts of prices.

COMMISSIONER: Our modelling will also provide some future generation mix. So we'll need to make sure that there is - - -

MR MICKLE: Absolutely. We've already had this conversation with your electricity modellers. So that will all be harmonised and we're ultimately relying on inputs for them. It's just that we have a model that – it needs to be done in a slightly different way to fit into the electricity model. So there's a bit of alignment to achieve but we're already making sure that occurs.

COMMISSIONER: Those key words of harmonisation make me happy.

MR MICKLE: Yes. Well, that's what we're seeking.

COMMISSIONER: Thank you very much for your presentations. We'll now adjourn.

MATTER ADJOURNED AT 12.29 PM UNTIL WEDNESDAY, 7 OCTOBER 2015