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DON TOWSON

Date and place of birth (if available): Creston, B.C.

Date and place of interview: May 22nd, 2013, Don's home, Calgary, AB.

Name of interviewer: Peter McKenzie-Brown

Name of videographer: Ty Reynolds

Full names (spelled out) of all others present: Don Towson

Consent form signed: Yes

Transcript reviewed by subject:

Interview Duration: 1 hour, 35 minutes

Initials of Interviewer: PMB

Last name of subject: Towson

PMB: I'm talking to Don Towson. Don has a long and interesting background in the oil sands. What we're most interested in, Don, is the work that you did with Petro-Canada in developing its oil sands project. But I want to go back a little bit with just a couple of general questions first. So just put this on the record, it's the 22nd of May 2013; we're in Don's home in Calgary. I would like you first please to give me your biography in two parts. So one is where you were born, high school, you know, what you studied, where you went to university and so on, and then after that your business career, so first our early life and then your career in the oil industry.

TOWSON: Well, I was born in Creston, B.C. For the first about eight years I lived in a small town just outside of Creston called Wynndel, B.C. I went up to Grade 6 in Wynndel, Grade 7 I went by bus into Creston, and after that the family moved into Creston and I went to Prince Charles Junior/Senior High in Creston.

PMB: Brothers and sisters?

TOWSON: I have one brother three years younger than I, who spent his career in the RCMP and now is retired, in Winnipeg.

In terms of university, I attended University of B.C., in Vancouver, and got a degree in chemical engineering. When I graduated from chemical engineering in B.C.; I received an Athlone Fellowship. The Athlone Fellowship was something set up by the British government to help the Colonies. The intent of it was that the people receiving the fellowship would go to England, work in industry in Britain to become familiar with industry and so on, and then go back to their home countries to apply this.

By the time I'd received the fellowship, the approach had changed a little bit because the industry in Canada, Australia, and so on was caught up to the British industry and most of the people receiving the fellowship then used it as a means of attending university in England. So I went to the University of Birmingham and received a doctorate in chemical engineering.

PMB: When did you meet Anne, and what kids have you had?

TOWSON: Well, actually I first met Anne very briefly when I was -- one of my summer jobs was working with the federal government as a surveyor, and we were surveying through B.C., and we camped at Anne's parents' campground in Harrison Hot Springs.

PMB: Are we talking about the early '60s here?

TOWSON: That's right, this is the late '50s, probably be 1958, '59. If there were any young ladies in the area, the crew chief had first call. So I had met Anne, but really didn't get to know her at that time, but we reconnected back in UBC; we both lived in residence there. And Anne got her diploma in teaching, and went teaching in the Okanagan while I was in England; and back and forth I was home sometimes, and Anne came to England for a while. We were married just after I graduated, and got back from England in 1964. We have two children, a son and a daughter.

PMB: Their names?

TOWSON: The daughter is Donna and son Earl. Our daughter Donna is married, has a daughter, our eight-year-old granddaughter; they live in Calgary. Both our daughter and her husband are teachers. Our son lives in Kelowna; he spent most of his career as an auto mechanic or automotive technician, I guess they're known as now. Recently he changed his job, and he's now an elevator/escalator safety inspector in B.C., and works out of Kelowna.

PMB: Okay, and now your career.

TOWSON: When I graduated from the University in Birmingham I sent out a number of letters to principally chemical companies in Eastern Canada, basically saying if I came to work for you what would I do? And I got basically the same reply from all of them, come and see us when you get back and we'll talk to you. My future mother-in-law at the time, Anne's mother, happened to see an ad in the paper in Vancouver, looking for doctorate degree graduates to work in Imperial Oil's Research Centre in Calgary, sent this to me. I wrote, and the Vice-President of Research sent me a long letter answering my questions, telling me the sort of things I would be doing and their training program, and so on. So I applied to them and got a job with Imperial in Calgary.

PMB: Imperial was the leader in petroleum research, really, in those days, wasn't it?

TOWSON: Yes, yes. Imperial certainly had the biggest centre. Shell established one a bit later, but Imperial had the research centre down on 50th Avenue South East. So I worked there for seven years doing primarily modelling, physical modelling as opposed to computer modelling on recovery of bitumen from the Athabasca Oil Sands or tar sands as they were known in those days. As I say, I worked there on that for seven years. I wasn't involved directly with the Cold Lake project at the time.

PMB: So the bitumen you would have been modeling would have really been from the Cold Lake deposit?

TOWSON: No, no, it was from Athabasca and it, in fact, of course, would be mined bitumen.

PMB: So this was the Syncrude Project.

TOWSON: It was bitumen that came from the Syncrude Project, yes. They put it in steel drums and shipped it down to Calgary, and we used that as the material. So I was doing physical modelling with Athabasca Oil Sands.

I had some connection with the Cold Lake Project because, of course, it was in the early stages of development when I was working in the lab. I worked there for seven years, and in those days the oil industry seemed to be in a fairly consistent ten-year cycle of ups and downs. So about every ten years or so there'd be a slowdown in the industry, and at that point Imperial cut back on their research activities, but they had a policy of in most cases not laying people off when there was a slowdown. They reassigned them. So I was shipped to Edmonton and spent three years working on the Rainbow/Zama area, not in heavy oil in this case, but in light oil. And that was miscible flooding in pinnacle reefs, so it was quite a different technology.

So I was then moved back to Calgary when, as I say, the other cycle came into effect and that was centralization/decentralization. At that point Imperial decided to centralize, and because I was in reservoir engineering I was working in the office as opposed to in the field. Was moved back to Calgary and spent one year working on Arctic gas. At that point I guess the activity in the Arctic was slowing down and I then got back into the oil sands area, working in reservoir engineering. What was initially a three-company organization which did not include Canadian Occidental. At that point it was City Services Canada, Atlantic Richfield Canada, and Imperial Oil.

PMB: And Gulf.

TOWSON: I'm not sure that Gulf was involved in the in situ part of it. Those three companies and possibly others owned probably two-thirds of the leases in the Athabasca Oil Sands. For the next year or two I worked with Imperial as sort of Imperial's technical representative on the technical committees associated with looking at what were the group going to do in terms of developing these oil sand assets that they had.

At about that time Petro-Canada acquired Atlantic Richfield Canada, so they acquired all Atlantic Richfield's assets in the oil sands and the technology they were working on. And again, shortly after that I left Imperial and went to work for Petro-Canada in their oil sands development group, and that was just after Petro-Canada had acquired Atlantic Richfield Canada.

PMB: What was the year of that, the mid-'60s?

TOWSON: No, that would be '73. So it was early '70s when Petro-Canada acquired Atlantic Richfield Canada. In fact, when I started work at Petro-Canada I effectively started work for Atlantic Richfield Canada, although it was then owned by Petro-Canada; they'd just acquired it, and they hadn't got in place, you know, pension schemes and that sort of thing.

PMB: That was really quite shortly after the federal government established Petro-Canada which was in '71 or '72 or something like that.

TOWSON: Something like that. I think, as I recall, Atlantic Richfield Canada was the first acquisition. So basically Petro-Canada, at that time, was Atlantic Richfield Canada, with a few people like Hopper, who were in place….

PMB: That's Bill Hopper….

TOWSON: Bill Hopper, yes. Who were basically put in place to start acquiring companies to build a company.

So I moved in there and I became, I guess, the reservoir engineer, looking after the development of Petro-Canada's oil sands assets, which were principally these leases in the Athabasca Oil Sands. Most of my career during that time which lasted until 1997, was involved with running field pilot projects associated with development of the Athabasca portion of the oil sands. I also was involved in Petro-Canada's heavy oil development; it kind of came and went in that initially I worked in the oil sands group; there was a separate group looking after their heavy oil assets. Later they combined the two groups, and our group became responsible for the development of their heavy oil assets, and then later on again they were split.

So through my whole career with Petro-Canada, my principal activity was working with field pilot operations, and attempting to develop some technology to be able to get the bitumen out of the Athabasca Oil Sands.

PMB: After Lougheed came into power, he established the Alberta Oil Sands Technology Research Authority, which basically provided huge amounts of funding for the oil industry. If I am Company A I would say well, I want to do some in situ experiments in Surmont or somewhere and then AOSTRA, as it was called, would pay half of that money. I think it was 50 percent of the funding, and the principal was that the province would own the patents, and they would eventually make them available to other developers.

TOWSON: Yes.

PMB: How much did that affect your work during that period?

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TOWSON: Well, it affected it principally through the activity I'm sure you have talked to a number of people about, the underground test facility. That was the major activity that AOSTRA was involved in.

PMB: Sometimes called the UTF.

TOWSON: UTF, that's right. I guess it would have been strictly with Petro-Canada. I was the Petro-Canada technical representative associated with UTF. We were one of the participants in the UTF Project.

PMB: That was constructed in the early '70s, and began operations in 1977 or '76?

TOWSON: Maybe. I don't have a good memory for dates.

PMB: Well, can you describe it for me?

TOWSON: Well, before the underground test facility was set up, in fact an individual working with Imperial Oil, Roger Butler, had developed a technology called steam assisted gravity drainage.

He developed the concept of SAGD. Initially, Roger's concept was a single well process where you had a long horizontal well with, if you like, tubing down the middle of the well itself. The well would be perforated or slotted so that material could come out; you'd inject steam down this pipe, down the middle, and it'd come out at the end of the pipe, run back basically across the top of the well itself, heat the bitumen up, which would flow into the well and could be produced out.

This technology actually was tested a couple of times in the heavy oil areas, and it did work but wasn't particularly effective, and the concept was then changed to a two-well concept, which is now the SAGD technology where you have one well to inject the steam, maybe five metres below that well another parallel horizontal well which is the producing well. The bitumen is heated up by the steam, moves down into the production well and is produced.

PMB: So you have two parallel horizontal wells; you pipe steam through the top one and then a steam chamber forms below that and then the lower pipe draws the melted bitumen out of that hole?

TOWSON: Yes. In fact, the steam chamber itself forms above the injection well, but as I'm sure you're aware --

PMB: Oh, heat rises.

TOWSON: Yeah. The big problem with the bitumen is that it's basically a semisolid in the reservoir, and geologically it ages, it'll move, but in practical terms it doesn't move. So you have to heat it up, warm it to lower the viscosity and to get it moving.

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So to get a SAGD project started, initially at least – there are different technologies potentially applied now, but the first application of this process you, in fact, inject steam into both wells, work it like a huff-and-puff project, inject steam, pull it back out, and take some bitumen out, and continue this until you've got heat between the two wells so that bitumen at or above the injection well could flow down into the production well. So once you got it heated up then you just inject into the top well, you form this steam chamber above the injection well, and the bitumen flows down into the production well.

PMB: And the huff-and-puff technique, basically you would blow steam in, pump steam into a well, and then you would try to withdraw oil through the same pipe; is that correct?

TOWSON: That's right. Right.

PMB: That was called huff and puff. And that was developed early in that AOSTRA period.

TOWSON: Yes. Huff and puff is the technology that Imperial was using in Cold Lake. That technology was really the only commercially viable in situ technology being used in the oil sands. It was attempted for quite some time in pilot projects during the '60s and '70s, and into the '80s in the Athabasca Oil Sands, but was not a very effective technology.

PMB: How would you explain that, is it because of the nature of the reservoir?

TOWSON: It's the nature of the reservoir and the nature of the bitumen. There are two principal differences between Cold Lake and Athabasca; one of them is viscosity. In round numbers the viscosity of the Cold Lake bitumen is about a hundred thousand centipoise. The Athabasca bitumen tends to be one plus million centipoise, so it's in order of magnitude, more viscose.

The other difference is the depth. Cold Lake is deeper, and for the huff-and-puff process, the way that works is you have to force the steam into the reservoir. You have to increase the pressure such that you can push the steam into the reservoir, and it goes into what in those days were known as fractures, and these fractures tend to be what are known as vertical fractures. So it's something that sort of is like this and goes out in a direction which happens to be generally northeast/southwest.

PMB: There's the technology called fracking or fracturing which, you know, usually is into fairly hard rocks, like shale and sandstone.

TOWSON: Right.

PMB: But, of course, the common idea about the oil sands is that the oil sands does not ever really need to be fracked or fractured. Can you explain that?

TOWSON: Yes, that's why I was saying initially it was called fracturing. And people have tried to come up with a different term for it now because the oil sands is not a solid rock, it's loose sand, effectively glued together by the bitumen. So I think another term that was used was parting.

So if you push hard enough with the steam, it will force the steam in and it'll kind of push the sand grains apart, and if it's fracturing anything it's fracturing the bitumen, although it's not a solid, it's a semisolid, but it kind of forces its way in. But it does tend to go in in sort of a vertical manner and follow a set direction. So it doesn't move out uniformly in all directions, which would have been very nice, it moves in a set direction established by the stress state in the bitumen, or in the oil sands themselves.

PMB: Now Canadian bitumen, as I understand it, this is consistent, has a very tiny layer of water surrounding the sand particle and then that is covered with the bitumen itself, and that the existence of that little layer of water, as I understand it, and I'd like you to explain please, is very important in terms of making it possible to separate the sand and the bitumen?

TOWSON: Yes. And that, of course, really applies to the mining technology as opposed to the in situ technology. So in the mining technology they go in and dig the oil sands out, put it through a process involving water at the present time, to separate the bitumen from the sand, and that's where the layer of water becomes really beneficial in terms of the separation. I don't think that it really makes much difference in the in situ process.

So back again to the huff-and-puff process, where you push the steam into the reservoir. In a plainer sort of manner, the second step in the huff and puff is you shut the well in and let it sit for a while, and what you're doing when you let it sit for a while is you let the conduction transfer the heat from the zone where the steam is out into the reservoir. So you have this zone; the heat will transfer out into the reservoir. You'll heat up some of the bitumen, turn it around, put the well on production; the bitumen and the condensed steam flow back into the heated zone and move back to the production well.

The reason for relating this to the SAGD process, because you're letting the heat transfer out by conduction, as this is happening it's cooling down, and you have to get the bitumen heated up to a certain level to make it mobile which means if you want the bitumen to be heated to a certain temperature the steam's going to have to be at a higher temperature because as it's heating out it's cooling down. And one of the properties of steam is that the temperature is directly proportional to the pressure, so if you want high-temperature steam you need high-pressure steam. So this comes back to why huff and puff is not a good process for the Athabasca bitumen. The first is that the viscosity is higher so you need higher temperature, but the depth is lower, and that limits the pressure you can put onto the steam going into the ground.

PMB: Because there's less overburden?

TOWSON: Less overburden. If you put too much pressure it'll come right up to the surface instead of staying where you want it.

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PMB: And you have explosions like the one at Jocelyn, for example.

TOWSON: Yes. So my interpretation, of course, is that that's the reason that huff and puff is not an effective technology for the Athabasca Oil Sands. Bitumen is higher viscosity and the depth is lower.

So coming back then to the SAGD process, Roger had come up with this concept to --

PMB: Did you know Roger Butler?

TOWSON: I did, yes. I worked with Roger in the lab in Calgary for a short time. He worked there just towards the end of the time I was at the lab, and then he moved to the university.

PMB: Would you like to just comment on him generally? What were your impressions? You're about the fifth person I've spoken to who knew him.

TOWSON: Very nice fellow, very easy to get along with, a very friendly person, somebody that was full of ideas. Roger always was thinking of something new, and a lot of the time thinking outside the box, I guess you could define it.

When I first heard of Roger he was working in Sarnia, and I'm not sure exactly what he was working on; it was something related to sulphur. But Roger wasn't one that would be restricted on the particular topic he was working on, so I think he started thinking about recovery technology, sort of in his spare time, and Imperial at that point I believe, recognized that he had something that had high potential for the oil sands, and he was moved to the lab in Calgary and continued there and in the university with developing the SAGD technology.

PMB: I just want to tell you this, that I interviewed Harbir Chhina who was his first graduate student when he was at the University of Calgary. He got to be very close to Roger, and they eventually set up a company together in the '90s. And, of course, Roger Butler died in 2005. But he said that he had seen a paper that Roger Butler had developed, and I'm pretty sure the date was 1969, in which he had come up with this concept. So it actually predated the first test on the thing by about ten years.

TOWSON: Yes, yes. I think Roger first developed the concept, as I say, when he was working in Sarnia, and that really wasn't his area of focus in Sarnia, so it took a while. Then he came to Calgary and worked in the lab there, and then moved to the university. It took time to, I guess, develop the concept, and also time to get the company interested enough to test it.

There was another constraint, of course. This technology requires horizontal wells, and this is the reason for the underground test facility. When that was developed the technology wasn't around to drill horizontal wells. What made it possible to drill horizontal wells were a number of technologies. First of all, was down-hole motors to run drill bits. A standard drilling rig has a long piece of pipe with a drill bit on the end. This pipe is turned from the surface, drills down into the ground, and you keep adding more pieces of the pipe until you've got the well deep enough. And as you can imagine, if you're turning the pipe with the bit on the end from the surface, you can't really go around very much of a corner before you're not going to be able to turn the pipe anymore.

So in order to drill a horizontal well, the first thing you need is a motor that goes onto the end of the drill pipe that turns the bit so that you can, in fact, go around corners with it. The next thing you need is you need to be able to, first of all, know where the bit is. You need to know where it is horizontally and vertically so that you make sure the bit is going where you want it to go.

So the next thing is something called MWD or Measurement While Drilling. You get a system, and the initial one was based on mud pulses. When you're drilling a well you inject mud down the drill pipe and back up through the annulus, and this mud brings the drill cutting up to the surface. So initially there was a system set up that sent back to the surface pressure pulses through the mud. These were measured at the surface, and instrumentation was there that translated this into information to tell you whether the bit was going up or down, and laterally sideways.

So now you've got a means of drilling horizontally. You've got a means of knowing where the bit is. The third piece you need is a controllable bit or a steerable bit because it's fine to know where the bit is, but unless you can move it if you get off track and go somewhere you don't want to go, you have to be able to move the bit back to where you want it to be. And steerable bits, generally the way they work is the bit has holes in it, or just behind the bit there's holes where the mud comes out of the bit, and the technology was developed to control the flow through these holes. So if you want to move the bit, you shut down the mud on one side and it would push the bit over.

So now you've got the ability to drill a horizontal well, you've got a down-hole motor to run the bit, you've got Measurement While Drilling to tell you where the bit is, and steerable bits to move it if it's not going where you want it. That technology was developed a few years after the start of the UTF project.

So coming back to UTF, in order to drill the horizontal wells they have to be essentially straight. They can have a bit of a curve in them, but they have to be basically straight. So the underground test facility was built by digging two shafts down into the carbonate that underlies the oil sands. It's competent carbonate so they put two shafts in, connected these, and then put tunnels out from them, and then drilled short essentially horizontal wells a little bit up, and then across the top of the carbonate at the base of the bitumen. So you had to tunnel down below the oil sands, you drilled the well up and out, and a second well above it. So in the case of the underground test facility, three pairs of parallel horizontal wells.

A steam generator was brought down into the underground facility, steam was injected and bitumen was produced, and this was the means of demonstrating the fact that SAGD was a technically viable process.

PMB: So let me just summarize a little piece of that which is that at the time SAGD was first tested, it was economically impractical because the technology was not developed to drill from the surface under -- or horizontal wells.

TOWSON: There was no known means at the time to drill horizontal wells from the surface.

PMB: Now, was there not another piece of equipment that you needed which was one that could identify -- let's say you'd already drilled the one horizontal well, another piece of equipment which would in effect enable you to drill horizontally to an existing well? So was there not a piece of equipment that enabled you to measure that you were exactly five metres away from an existing well?

TOWSON: I'm not sure that there was a technology that you could run that would tell you exactly where you were relative to the other well, other than the technology that told you where the drill bit was. You drilled the first well. If all went well, you drilled this horizontally and you knew where the first well was. You then controlled the second well to maintain about a five-metre spacing.

Just to finish that up, there is another technology that was developed which was called Logging While Drilling. Logging is a technology where you run a tool into the well that gives you some information about the well, and in standard vertical drilling you drill the well and you run the logs in, get the information you want. Logging While Drilling has the tool that does the logging attached to the drill pipe and it gives you the information while you're drilling. This certainly will give you information on the reservoir you're going through, but I'm not aware of any Logging While Drilling that would tell you where you were relative to another well.

So that the underground test facility then was the test bed, if you like, for SAGD, and it demonstrated the SAGD was a technically viable technology. During the time that this was going on a number of companies, including Petro-Canada and Imperial, were in fact looking at developing mining schemes to use not to mine the material, but as a base for drilling SAGD wells into the oil sands.

Just about that time a couple of things happened; again, a little bit of a downturn in this, sort of what those days was kind of a regular ten-year cycle, a bit of a downturn. Oil prices were probably down. This concept really wasn't pursued very far. There was a little bit of paperwork done on putting in mines and shafts and tunnels to produce the bitumen. I guess fortunately just about that time also, horizontal drilling technology was developed; the three components I mentioned. They weren't all developed at the same time, I think the down-hole motors were developed before the other technologies, but they all came together at about that time.

PMB: This would be in the '90s?

TOWSON: Late '80s, early '90s.

PMB: Late '80s, early '90s. All right.

TOWSON: They all came together, and in fact at that point three well pairs were drilled from the surface at the underground test facility.

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PMB: I think there were 13 companies, or thereabouts, who were involved in additional tests at the underground test facility, and so you would have represented Petro-Canada on that?

TOWSON: That's right. I was their technical representative at the UTF project.

PMB: And can you give us any comments on that? What did you do over those ten or 12 years that you were the tech rep?

TOWSON: Well, we had regular technical meetings. The technology development, if you like, was controlled by the UTF Technical Committee. The technical committee had representatives from all the participants. We had regular technical meetings where we helped develop the plans for the pilot project, we monitored the pilot project, we looked at where the information was going, maintained or provided input onto the operation of it in terms of whether additional injection was required, additional pressure required, that sort of thing.

PMB: So it was a collaboration among the companies who when the project, or even before the project shut down, became competitors in SAGD?

TOWSON: Right, right. And, of course, the technical committee was also highly involved in the design, implementation and operation of the surface-based horizontal wells. There was quite a bit of debate at that time as to whether SAGD would operate effectively with surface-based wells as opposed to the mine-based wells, the reason being with the mine-based wells the production end of the well was actually lower than the injection end because the well went like that, so gravity would allow the material to flow back to the production end of the well, and the control of the well was much easier.

You have to have fairly good control on both the injection and the production. If you produce too fast you get a bunch of steam coming back through the production end. If you produce too slowly the thing cools down and stops operating, so it's a fairly precise control needed. And there was some debate among the industry, among the participants and the technical people, as to would you in fact be able to control it sufficiently from the surface where the production end was quite a bit higher than the injection end? And, of course, there were people that felt that you wouldn't be able to, and people that felt you would.

So it was of considerable interest to get the surface-base wells in place, and get them operating to see, in fact, was it technically viable not only to run SAGD, but to run it from surface-based horizontal wells. And of course as we know now it is, and it not only turned out to be technically viable, but commercially viable.

PMB: Yeah, it's been huge.

TOWSON: Yes.

PMB: Canada's oil industry hit the ball out of the park on that.

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TOWSON: Yes. Yeah.

PMB: Now, Don, when I was looking through your resume and looking online, and speaking to different people, I found that you were involved, and you'll have to explain to me what your involvement was, but in a project which apparently goes back to the late 1950s to use electrical heating to try to mobilize the oil sands. And this project, from what I gather, went on for two or three decades. Would you explain that to me please, 'cause this is brand new to me.

TOWSON: Well, just to give a little bit of background to the electrical heating process, as I mentioned talking about the huff-and-puff process, and that was the technology that was being piloted by pretty well anybody working in the Athabasca Oil Sands, trying to develop a means of using huff and puff as a recovery technology in the Athabasca Oil Sands, and we talked a little bit about why it's not a particularly effective technology, and I'd suggested that forcing the steam in tends to go into kind of horizontal partings.

An ideal technology if you're using parting or what was for a while called fracturing, would be if you could get this to occur horizontally at the base of the injection well, so instead of going out this way it would go out in a pancake, underneath the oil sands. Then you've got a much more effective means of producing the bitumen because the heat from the steam would rise up a little bit, heat up the bitumen, it would flow down into this pancake and flow back into the production well, and you've then cleared up a little bit of space in the sand so the heat can easily -- you don't have to depend on conduction. The steam could rise up, contact some more oil and move it down.

PMB: And the permeability of the sand would be greater, wouldn't it, after some of that bitumen moved?

TOWSON: Yes, the permeability of the sand is extremely high in the oil sands. Permeability is measured in darcies. Most rock has permeability of millidarcies or a thousandth of a darcies. The oil sands, once you've got the bitumen out of the way has a permeability of darcies, one, two, five. I've seen some as high as seven darcies; extremely high permeability. So once you get the bitumen out of it, very good permeability, and you heat the bitumen up, it will flow.

I think it's probably fair to say most of the companies working in the oil sands, one of the things they were trying to do in those days was create what we called horizontal fractures or horizontal parting. Part of the difficulty in those days was we didn't have good geotechnical knowledge, and I think the engineers in general weren't aware that there was a stress state in the oil sands which, except in very special conditions, would cause the parting to be vertical rather than horizontal.

There are two conditions where you'll get horizontal fractures. One is if you're quite shallow. the other is if you've preheated the reservoir. In fact Imperial was able to create horizontal fractures or parting in some of their Cold Lake operations after they'd heated up, but when it's cold basically this steam will go into a vertical manner not a horizontal manner. So a lot of effort was spent in trying to get horizontal fractures, and I think now that we understand the stress conditions in the reservoir and so on, it's understandable that that was something that was not going to be achieved. So because of that people were looking at what other mechanism might we have to heat the reservoir up? One is combustion. Combustion is where you light a fire in the reservoir, and use the heat from the fire to heat the bitumen up.

PMB: This is fire flood.

TOWSON: Fire flooding, yes. The critical part of it is the concept that it's a flood. Flood means you have to move from an injection well to a production well. So you can get the fire going, that's not difficult. In fact, if you inject air into the reservoir, in most cases it will ignite just by injecting the air. Sometimes you need to have a little help, but you can quite easily warm it up a little bit, or put something in to help the ignition. You can easily get a fire going in the oil sands, interestingly. The difficult, of course, is you've got the fire going, you've heated the bitumen up, it will move, but you have to get it from the well you're heating it over to the production well, and that's blocked by semisolid bitumen. So it's really not a practical process to use in the oil sands.

There is a technology now called toe-to-heel process where they've got a mechanism to overcome this problem. So combustion is not a potential process, or it wasn't in those days. Certainly fire flooding is not a possible process. There has to be an alternate mechanism like the THAI process that allows it to work.

So Atlantic Richfield, in their research centre in Dallas, were thinking that it is possible to move electricity through a reservoir. One of the difficulties is --

PMB: Now we're going back in time. So where are we now in time, roughly?

TOWSON: This would be early '70s, mid-'70s. Just about the time that I was finishing with Imperial and moving to Petro-Canada.

So ARCO had come up with this technology, and at about that time. Atlantic Richfield Company. Petro-Canada, of course, by that time had acquired Atlantic Richfield Canada, and had acquired the rights to this technology, and the concept of this was if you put two electrodes into the reservoir, as long as there's some water in the system between the two, because bitumen is a good insulator, to get heat you have to have current flow, so you need some degree of conduction in the reservoir to be able to heat it up. So you need some degree of conduction in order to get current flow which will produce heat. So they were thinking if we had a couple of electrodes, and put a voltage between the two, you'd get some current flowing, and you'd produce some heat in the reservoir.

So then they took it one step further, and they said if we're going to produce heat why don't we use three-phase electricity?

PMB: Now what does three-phase electricity mean? That's a totally new concept to me.

TOWSON: Well, I guess maybe an easy way to put it is because electricity is alternating current, if you have a point in the alternating current, it can go negative or it can go positive. So you've got a difference between the centre point and the plus, the centre point and the minus, and the difference between the plus and the minus. So you can get three voltage differences in alternating current by using the three phases.

But something that might be a bit more readily knowledgeable is, your stove works on 220 volts. The power that comes into your house is three-phase. it's 110, 110 and 110, but the lights and everything work on 110, which is one phase, one of the phases, but 220 will give you the difference in the two directions.

So you've got what's called three phase which means there's three components to the electricity, each of which has a voltage difference. In one case it'll be a plus voltage and a minus voltage, but it's a voltage difference which will cause a current to flow. So they said if we use three-phase electricity we'll put in three wells, and we'll put one phase on each well. So now you've got a triangle with electricity flowing in each leg of the triangle. So the concept was to put wells into the ground, bring in three-phase electricity, put one phase on each well, and get current flowing along each arm of the triangle. So this was something that, again, involved the PCEJ Group.

PMB: Okay so PCEJ was Petro-Canada, Coneco, E was who?

TOWSON: It was Petro-Canada; City Service Canada, which changed later to become Canadian Occidental which fortunately it was still C; E was Esso because in those days the operating portion of Imperial Oil was called Esso Resources.

PMB: And J was JACOS.

TOWSON: J was JACOS. So the PCJ Group which was operated by Petro-Canada was now operating this electric preheat process, and I'm not familiar with the setup that was in place, but ARCO Research was still involved in providing technical backup for this operation even though Petro-Canada now owned Atlantic Richfield Canada.

PMB: You were talking about using electrical systems to heat the oil sands.

TOWSON: Yeah, and again using --

PMB: And we're back in the 1970s at this point.

TOWSON: Yes. So it's using three-phase electricity, and I'm afraid my description of three phase wasn't very precise. But basically, as I said, three phases allows you to have three wells and heat between each of the three sides of the triangle formed by these wells.

One of the difficulties with doing this, of course, is you can't just energize the well. If you do that you're going to be energizing the ground that the wells are going through. So you only want the….

PMB: And what would be the implications of that? Could you be electrocuting people?

TOWSON: You could, yes. And consequently there was high fences put up around all the wells to keep people out whenever the power was put on.

So what you want to do is apply power only to the portion of the well that goes through the part you want to heat, in other words the oil sands. That means you need insulators to insulate the well pipe from the portion of the pipe that goes through the oil sands, and there was a lot of work, time, and effort spent in developing insulators, and in fact the insulators were developed by the Japanese participants in the PCJ Project. Through some of their industry partners in Japan we were able to develop ceramic insulators that were probably something that a lot of research would have been needed on if this technology had been continued because they were very expensive. But, of course, prototype insulators, prototype anything is always expensive.

So insulators were developed. Then a cable had to be run down to the portion of the well that was to be electrified. Power was put on, and it was let run for a period of time. In addition to the --

PMB: What was the amount of electricity that you were sending down into the well? What were the voltages?

TOWSON: I don't recall the numbers offhand.

PMB: Would it be in the hundreds or the thousands?

TOWSON: The voltage would be in the thousands, and I'm sure I can find that information but don't know it offhand.

PMB: Those details aren't important.

TOWSON: So the electricity was turned on, the wells were heated for a period of time. But as I was saying, in addition to the three wells that were being heated there were observation wells with temperature monitoring and pressure-monitoring devices in them. So we were able to monitor the temperature changes in the reservoir between the wells. And these were monitored, and I guess as expected the reservoir heated up. It didn't heat uniformly along the well. it heated up more in certain areas than in other areas, and this tended to be related to the percentage of water in the zone. If you had a little bit more water, you got a bit more current flow and you probably got a little bit more heating. So it did heat the zone in between the wells.

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Once the heating was at a point where we felt the temperature was warm enough to mobilize some of the bitumen, the electrical system was taken out and we injected steam into -- I don't recall the exact layout now, but we'll say we injected steam into one of the wells and produced from one of the wells, or maybe injected into one and produced from two, and produced a little bit of bitumen and quite a bit of steam.

In looking very closely at the well logs and the information on the well later, it was found that there was a very thin, so thin that it wasn't really noticed in the early looking at the logs, zone of very high water saturation, and this formed a flow channel for the steam so that you got early steam breakthrough in the production well.

And we did produce bitumen. We didn't produce a lot of bitumen, and in terms of the particular operation it probably wasn't commercially viable the amount of bitumen we produced with the amount of steam we put into the reservoir. But we certainly demonstrated that the reservoir could be heated electrically. With the right type of reservoir and the right means of steam injection and production we probably could have got to a point to produce commercially viable amounts of oil.

Once again, we hit that cycle, and just about that time, this was in, I guess in the early '80s. You may recall, I think it was the early '80s where oil prices went way down. Anyway, just about this time was again a sort of down cycle in the price of oil, and the technology was kind of put aside. This is something we'll have another look at when oil prices are back up and it may be feasible to do some additional pilot testing, and see if we can't get this to a point of commercially viable technology, 'cause the wells were very expensive, the cost of electricity, of course, is not low. It didn't appear to be a commercially viable technology at the time, but it had enough potential that with higher oil prices it was probably something that the participants would have another look at.

PMB: Now I showed you, before this interview began, an article from the *Journal of Canadian Petroleum Technology* which I think this was published in 2006, so it's much more current than the research that you helped conduct. But what I thought was really fascinating is that this report, and I'd showed you my highlighted comments on some of their findings and their conclusions. They seemed really quite optimistic on that.

TOWSON: Yes.

PMB: Now based on having looked at this and I understand briefly just before our meeting, what would you say about that?

TOWSON: Well, I guess one of the big differences between the two technologies is that particular technology was developed for very shallow oil sands.

PMB: Now that's the recent one?

TOWSON: The new technology, yes. It's for very shallow oil sands. It's a more comprehensive technology.

PMB: And that technology is called the Electro Thermal Dynamic Stripping Process which is a trademarked process.

TOWSON: Yes. Yeah. It was developed for very shallow oil sands, and the main advantage of very shallow oil sands is you can use much less expensive wells. That particular technology requires a large number of wells.

PMB: Are these vertical wells?

TOWSON: They're vertical wells. And because you can use fairly inexpensive wells you can, if you like, afford to use more wells. It's, as I say, a more comprehensive technology, and the technology we were looking at was strictly a preheat process. It was a means of getting some of the bitumen mobilized between an injection well and a production well such that you could then inject steam without having to put it in at very high pressure, and move the bitumen. The other process is a more complete process. I'm not familiar in total with how the process works, but I do know it was developed for application in very shallow oil sands.

PMB: Now when you say "very shallow", you're obviously not talking about something that's surface mineable, but how deep might it be?

TOWSON: Immediately below the surface mineable. And the advantage of that process, of course, is that it doesn't require high-pressure steam so it can operate in this zone which has been considered to be a difficult zone to operate in, and that's the zone immediately below -- anything below 75 metres down to a few hundred metres. Because you're very near the surface you can't use high-pressure steam which means you can't use very hot steam which normally you need to mobilize the bitumen.

PMB: Now, the article,'s first conclusion, my jaw just about hit the breakfast table this morning…. It says that "this process is an additional in situ thermal recovery technology for the production of bitumen from oil sands". I mean it's peer reviewed, I presume, to be in this paper. That sounds like an amazing claim.

TOWSON: Well, it certainly is an additional technology. I guess I'd define it only because of lack of knowledge of what the status of that project is, an additional potential technology for recovering bitumen from the oil sands. And it certainly addresses that shallow zone that's been a challenge to date in terms it's too deep for mining and it's too shallow probably for SAGD, and certainly for huff and puff. So I know that there's been some field testing of this technology, and I'm not familiar with the status of that testing, whether it's proved to be technically viable, and equally important, proved to be economically viable.

PMB: It goes on to say in at the conclusions. I'll leave you this paper, you might want to study it when after I've left. But it says that "the recovery factor of this process is comparable to that of a good SAGD project".

TOWSON: Well, it certainly could be, and I don't know whether that conclusion is based on field testing or based on computer modelling.

PMB: Throughout this paper they actually do discuss a field test, so I believe it is based on a field test, and it has all kinds of mathematics in it which I don't have a clue. I can't even recognize a lot of the Greek characters, so that didn't help me very much at all, but I will leave this with you. Any other thoughts on electric-based bitumen recovery?

TOWSON: I guess certainly with the development of the SAGD process I don't see an application, in general, of electric preheating for the oil sands. Any application of electric heating in the oil sands is one of two possibilities that I would say. There has been some application of electric heating as a, if you like, well stimulation technology, or maybe even a well cleanup technology, because when fluid flows into the well, the closer you get to the well the smaller an area you have for the fluid to flow through. And if you have anything immediately around the well that's constricting the flow it has a much greater effect than if you have something further out. So there's a possibility of the application of electric heating as a little sort of stimulation right around the wellbore and maybe a well cleanup technology.

PMB: So let me make sure that I understand what you've just said. These folks are saying this can be used in a, you know, restricted way, and then for certain kinds of shallow in situ production, but I think what I just heard you say is that it's not likely to be helpful to use electrical stimulation of a field before you apply something else like SAGD?

TOWSON: Yeah, I don't see electric preheating as the concept that we were testing in the PCJ electric preheat project as having great application. There's potential application in the shallow areas of this other technology. There may be some application for heating immediately around the wellbore, but not as a means of initiating steam injection or some other technology in the oil sands.

PMB: Okay. And I guess I'm going to give the end of the discussion to you, but I do want to ask you one other question, whether, electricity being a fairly expensive commodity, you know, compared to gas. Mind you natural gas is rising in price quite a bit right now. Is that one of the reasons it's not economic, or is it just that technically it doesn't work, or is it both of the above?

TOWSON: It's both. Technically it works. We certainly demonstrated we could heat the reservoir up with electricity. So I think in the application, the applicability of it maybe is more the cost of electricity, the benefit you can get for the cost of the electricity. So it's -- I think it was demonstrated to be technically feasible to use electricity to heat the reservoir. It's probably then more an economic consideration than a technical consideration so that it becomes maybe a niche player, if you like, in terms of bitumen recovery.

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PMB: And I think that that covers off my question. There was a proposal out there a year or so ago about the idea of creating a nuclear power station in Alberta and, you know, the idea was to use some of the waste heat to heat the oil sands, and then, you know, because it's low-cost electricity, low greenhouse gas emissions electricity, the electricity could actually be used to heat steam boilers for further application. Any thoughts on that, just to throw away?

TOWSON: I suppose it's certainly a potential. Again, it would have to be demonstrated to be economically viable. And, of course, there's the difficulty of anything nuclear of getting both agreement of the people living around it, and the agreement of the government and the various authorities to have that applied. Again, it's kind of the same sort of situation as electrical power generation; it's an alternate source of electrical power. It has some very difficult considerations, disposing of spent fuel and so on. You have the same concerns with, even though it's on a smaller scale, an application (indiscernible).

PMB: Now, you would have been around and active in the late '50s early '60s. Do you remember the proposal to detonate a nuclear device in the oil sands?

TOWSON: Yes.

PMB: And I actually did talk to Premier Manning about that once, and this was ten years or something before he died. The idea was put to rest in '61 or '62 when there was a lot of concern about nuclear energy, radiation poisoning and so on. But the idea, as you remember, was to take, I think it was a nine kiloton bomb and explode it in the oil sands, and then that would create a crater into which the oil would seep, and then you could just suck it out with big straws. That was the theory. Do you have any thoughts on that?

TOWSON: Well, I guess my understanding at the time, and it sort of stated this, that that was stopped by Diefenbaker; basically the federal government. Potentially the Alberta government also was instrumental in having that project not go ahead.

As it happened, anything I'd read about it later was that was a good thing because it wouldn't have worked anyway. The concern that people expressed later when they did more analysis of it was that once that device had been exploded, all the sand in the immediate vicinity would be turned to glass, and basically there'd be no -- first of all, there'd be extremely high temperatures for a very short time. You wouldn't get a lot of heat out very far into the reservoir, and secondly there'd be no means for the oil to flow back into the reservoir because it would be encased in glass. That was certainly the sort of gist of some of the articles I read saying that fortunately it didn't go ahead because technically it wouldn't have worked anyway.

PMB: Okay, fair enough. That's my last question. That's one of my favourite ideas. A lot has been written about that and they mostly come to the same conclusions as yours.

This is open, anything you want to say. What would you like to add to this interview that you think is important to be known?

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TOWSON: I don't know particularly. You know, there was a lot of effort expended in trying to develop technology to get the bitumen out of the Athabasca Oil Sands. Part of the effort maybe turned out later to be wasted effort, like some of the activities trying to create horizontal wells, largely because we were unaware of the geo -- basically the stress situation in the reservoir.

PMB: You just started to use a word, basically because we were unaware of the...?

TOWSON: I'm trying to think of the word that really --

PMB: Geophysics?

TOWSON: No, geotechnology, I guess. It's basically the fact that a stress state exists in the oil sands. There's stresses in the oil sands. Even though they're loose sand, but it's basically loose sand glued together with semi-mobile bitumen, there is a stress direction which tends to be northeast/southwest, and that influences the direction that the steam will flow if it's forced into the reservoir.

And I guess once we got people that were familiar with this, and doing some measurements, it may be that in fact people weren't even aware of this stress state, and I think that was certainly the situation, that those of us working in the industry weren't aware that stresses existed in the oil sands. The stress direction I think is probably understandable.

If you look at the stress direction it's at right angles to the direction of the Rocky Mountains. So when those mountains were pushed up and formed that created a stress; it squeezed it and created the stress state in the oil sands, and that stress state controlled or controls where the steam will go when it's forced into the reservoir.

PMB: That's very interesting.

TOWSON: A lot of effort was expended, and certainly this is not any negative indication on the people working there, myself being one of them. We weren't aware of it, and it may have been that the geotechnical people at the time weren't even aware that this stress state existed, but certainly it -- I guess it maybe indicates that you need to get all disciplines involved, if you can, in any activity you're carrying out.

PMB: Now, your comment about the stress state is a very interesting one. I'm going to ask you this question: A few weeks ago I was reading what to me was a very difficult technical paper which summarized the 11 major theories of where the bitumen came from, how it originated. Do you have a favourite theory? I'm going to put your credentials on the table here. You've got a PhD in chemical engineering, and you are a professional engineer so you're probably more likely to come up with a good idea than the other people I've interviewed.

TOWSON: Well, the general concept of the origin of the bitumen in the oil sands that I'm familiar with is that the material, as with any petroleum, originated deep in the earth, probably in shales and migrated up towards the surface as, I guess, is the commonly accepted theory of how petroleum originated. It originates down deep and it moves up until it hits a trap, something that stops it going any further up.

This was relatively light oil when it was formed. It moved up into the oil sands and was basically trapped throughout most of the oil sands by layers of different material on top that stopped it coming to the surface. There were also layers of water associated with the oil that was in the oil sands, that there was bacteria living in this, or moved into this water, moved through the oil sands, and these particular bacteria live on hydrocarbons. But bugs, like people, are fussy what they eat; they'll only consider consuming the lighter ends of the oil. So they basically consumed the light ends of the oil and left the heavy stuff. So that would be the basis of the origin of the bitumen.

PMB: Wouldn't it make sense for some bug, some bacterium, to develop which could eat the heavier and heavier and heavier bits of the oil sand?

TOWSON: That's certainly a possibility. I guess they seem to be able to find bacteria that will live on anything. Whether the conditions just weren't suitable for them to develop or there's just too much of it that there hasn't been enough time for them to consume --

PMB: And you don't have any thought about whether the oil might have originated as sea creatures, or one of the ideas is that it actually comes from coal or even comes from wood that's in decay.

TOWSON: I certainly haven't been involved in any -- in that aspect of it, the sort of biological aspect. I know that there's two theories of the origin of hydrocarbon. One is that it originated from materials, and usually thought to be dinosaurs and the plant life that existed during that time. The other one is that the hydrocarbon has been in existence all the time. It came into existence when the Earth was created. That one is certainly the least accepted of the two theories of origin.

PMB: But if you look at a lot of the planets they have atmospheres of methane, and it's my understanding that at one time the planet Earth actually had an atmosphere of methane, you know, early, early, early on in its existence. We're talking about 4 billion years ago or something.

TOWSON: Well, there's certainly a group I guess you might call it, there are certain scientists that still hold with the theory that it existed from the time the Earth was formed. There have been a number of tests, and generally these are very deep-drilling tests to see if they can find evidence of hydrocarbons, and I guess the conclusion to date is inconclusive. They haven't been able to find any evidence of this basis for hydrocarbons, but they equally haven't found anything that would prove it false. But I think the majority of people that work in this area, whether it's geologists or bacteriologists, whatever, hold with the theory that it was formed from plant or material, or both.

PMB: Okay, I think that covers it. Last point goes to you, any last point you want to make?

TOWSON: No, I don't think so.

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PMB: We've covered a lot of information.

TOWSON: It was an extremely interesting career I've had; a lot of fascinating things going on and a lot of fascinating people.

PMB: When did you retire?

TOWSON: I was early retired from Petro-Canada in '97.

PMB: That was just as oil prices were in free fall, wasn't it?

TOWSON: Yeah, and that's when Petro-Canada was -- actually, that was the fifth round of layoffs I'd been involved in. Prior to that I had been laying people off, and at that point I was early retired; not unhappy; I got a great settlement. And I did some consulting for a few years. I worked with the federal government in the Industrial Research Assistance Program for ten years, and I guess other than teaching this course occasionally, the last five or six years I've been fully retired.

PMB: I thought I saw on your resume that you had been involved in helping to organize one of the global conferences on the oil sands, or am I thinking of somebody else? I'm thinking of someone else.

TOWSON: I certainly was involved for quite a number of years with UNITAR.

PMB: That is the UNITAR Conference?

TOWSON: Yeah. And I was certainly involved with UNITAR Conferences. I was the representative with UNITAR for a number --

PMB: And UNITAR is United Nations Institute for --

TOWSON: -- Technology and Research.And they had a tar sands and heavy oil group that had headquarters in New York.

PMB: At the UN Building.

TOWSON: Well, their offices weren't actually in the UN Building but, of course, the UN and UNITAR and so on had people all over New York, and --

PMB: But one or two of the conferences were held in Alberta weren't they?

TOWSON: They rotated.

PMB: Was it every three years?

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TOWSON: I think it was every three years, yeah. There were three principal countries involved, Venezuela, the United States, and Canada, and they rotated around. It would be in Venezuela one year, in the U.S. one year, and Canada one year, and I think we held at least two in Canada, one in Calgary and one in Edmonton..

PMB: Does that organization exist anymore?

TOWSON: I don't know that it exists today. It certainly stopped running these conferences. Actually, after I was out of the business they got Russia involved as well, and I believe they actually held one conference in Russia. The sort of activity shrank. They stopped holding conferences. They had a Centre for Tar Sands and Heavy Oil I think it was called, that had quite an extensive collection of papers and books and so on. That may still be in existence. I don't think the centre itself is active anymore.

PMB: Okay, I think that's all we need.

TOWSON: Okay.

PMB: Congratulations on a great career, and thank you for a very, very interesting interview, and I'll send you a transcript, and I'll ask for your corrections on it.

[END OF RECORDING]

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