Flow Control Devices in SAGD – Part II

By

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Part I of this article was published in Spring 2018 in the Journal of the Canadian Heavy Oil Association, and focussed on the overview of Flow Control Device (FCD) technology, rationale and Key Performance Indicators for FCDs, and some system-design considerations. Part II will expand discussion of operator experience, and to what extent perceived benefits of the technology have materialized.

The table in Figure 1, shows the current deployment statistics of Flow Control Devices, as derived from in-situ operators' performance presentations made to the Alberta Energy Regulator (AER):

Inflow/Outflow Control Devices utilization in SAGD projects in Alberta

(Data obtained from In-situ performance presentations made to AER under Directive 54)

					Producer wells with ICDs				Injector wells with OCDs			
					Deployment		Timing of deployment		Deployment		Timing of deployment	
Company Name	**Project Name**	Nameplate capacity (bpd)	Last updated	No. of wells with FCDs	On Liner	On Tubing	From Start	Retrofitted	On Liner	On Tubing	From Start	Retrofitted
Athabasca Oil Corporation	Leismer SAGD	20,000	May 2018	17	7	4	8	3	2	4	6	
BlackPearl Resources Inc.	Blackrod SAGD Pilot	500	Feb 2017	1						1[a]	1	
Canadian Natural Resources Ltd.	Kirby In Situ Oil Sands	40,000	Sep 2017	22	11					11[a]		
Cenovus FCCL Ltd.	Christina Lake In situ	210,000	Jun 2018	5	3	2				a,b		
Cenovus FCCL Ltd.	Foster Creek In situ	180,000	May 2018							a,b		
Cenovus Energy	Pelican Lake SAGD Pilot	500	Apr 2016	2	1			1		1[a]		
CNOOC Nexen	Long Lake Kinosis Oil Sands	90,000	Apr 2018	70		11		11		59[a]	36	23
Conoco Phillips	Surmont SAGD Phase 1	30,000	Apr 2018	28	12	8			8			
Conoco Phillips	Surmont SAGD Phase 2	110,000	Apr 2018	59	27	27			5			
Devon Canada Corporation	Devon Jackfish	105,000	Oct 2017	5	2	3				a,b		
Husky Energy Inc.	Sunrise	60,000	Oct 2017	69						69[a]	69	
Husky Energy Inc.	Tucker	30,000	Sep 2017	36						36[a]	36	
Japan Canada Oil Sands Limited	Hangingstone Expansion	20,000	Feb 2018	5		2[a]	2			3[a]	3	
MEG Energy	Christina Lake Regional Project	80,000	Jun 2018	2		a,b				2[a]	2	
Osum Production Corp.	Orion In Situ Oil Sands	10,000	May 2018	3						3[a]	3	
Pengrowth Energy Corporation	Lindbergh SAGD Project	12,500	Jan 2018	25	5		5			20[a]		20
PetroChina Canada	MacKay River Commercial Project	35,000	Apr 2018	5	2		2			3[a]	3	
Southern Pacific (Viceroy)	STP-McKay River Thermal Project	12,000	Mar 2015	18	6			6		12[a]	12	
Suncor	Suncor Firebag	203,000	May 2018	9		9				a,b		
Suncor	Suncor Mackay River Project	38,000	Nov 2017	12		12				b		
			Total	**393**	**76**	**78**	**17**	**21**	**15**	**224**	**171**	**43**

a. Steam Splitters/ Flow Splitters

b. Number of wells was not reported, and not included.

Figure 1: Source, https://www.aer.ca/providing-information/data-and-reports/activity-and-data/in-situ-performance-presentations

Key Performance Indicators and Selected Operators' Experience:

Among the performance indicators listed in Part Iof this article, the salient ones are those that can be correlated most directly to production performance:

1. Increased Oil rates
2. Reduced Steam Oil Ratio (SOR)
3. Avoidance of "Hot Spots" and Steam breakthrough
4. Improve reservoir conformance longitudinally along the wellbore

Part II reviews the experience of select operators' and will summarize insights with FCDs to the extent that this information has been shared in the public domain. Conoco Phillips's case is discussed in detail as Surmont has the most intensive application of FCDs among all SAGD projects.

Conoco Phillips Surmont Project

Conoco has been the biggest user and can be considered as the pioneer of FCD deployment in SAGDs. The earliest reported use of FCDs was in 2011 and has been described in technical papers such as SPE 153706-PA and subsequent D-54 presentations made to the AER. Currently Conoco has 87 deployments of FCDs in Surmont Phase I and Phase II as shown below:

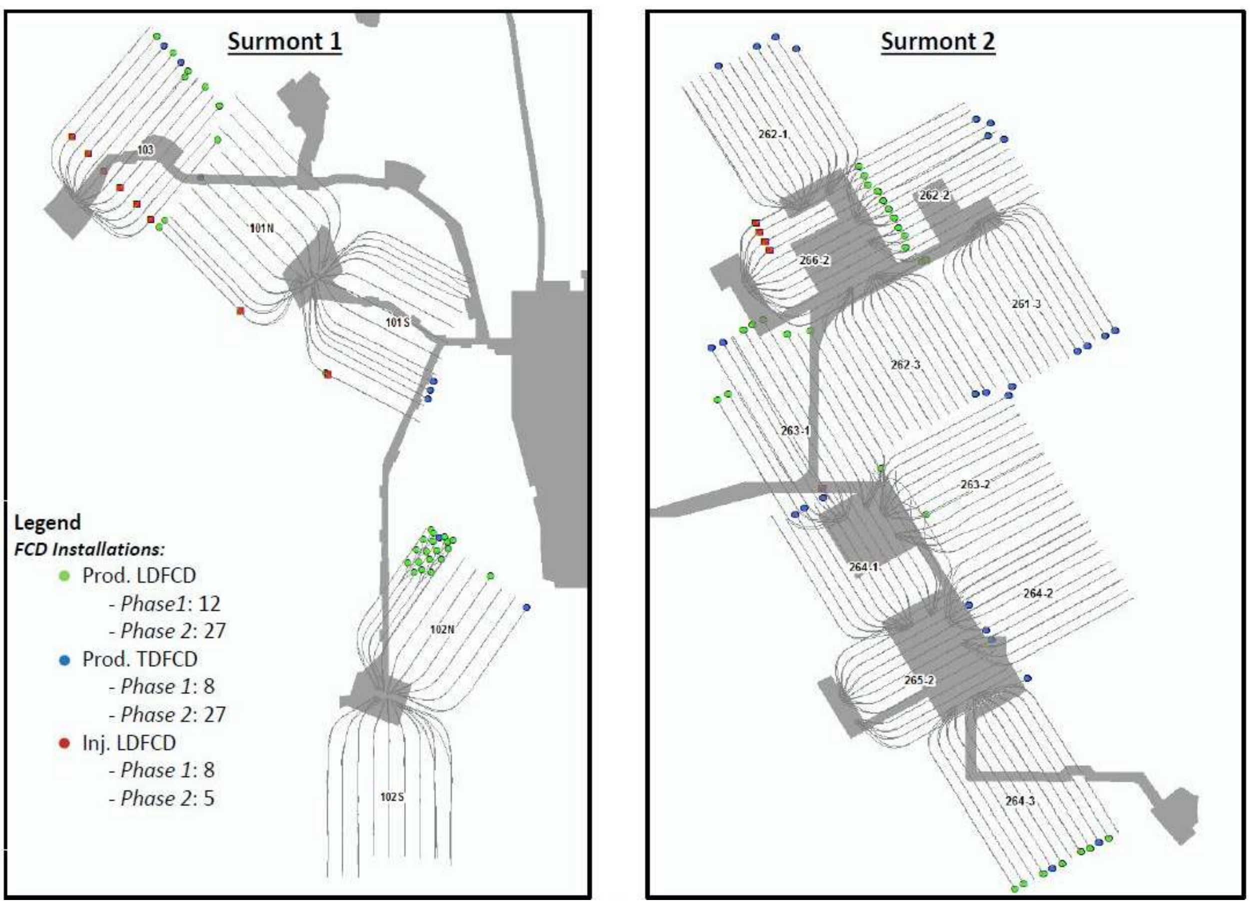

Figure 2: Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, April 4 2018

As seen in the Figure 2, the majority of FCDs in Surmont Phase 1 have been deployed on Pad 103 and Pad 102N. In Surmont 2, Liner deployed FCDs are mostly concentrated on Pads 266-2, 263-1, and 264-3, whereas Tubing deployed FCDs are distributed over several other pads.

It will be of interest to see results of 4D Seismic monitoring of these 5 pads that have a significant number of FCDs. 4D seismic volumes represent the acoustic impedance anomaly roughly correlating to a 60 degC isotherm which, in plain language means that if the anomaly exists on seismic then likely the bitumen in that area of the reservoir has been thermally mobilized.

<u>Pad 102 N – Surmont Phase 1</u>

4D Seismic results are summarized on Figure 3 for Pad 102N. The first SAGD well with FCDs (well 06) is highlighted with a red box.

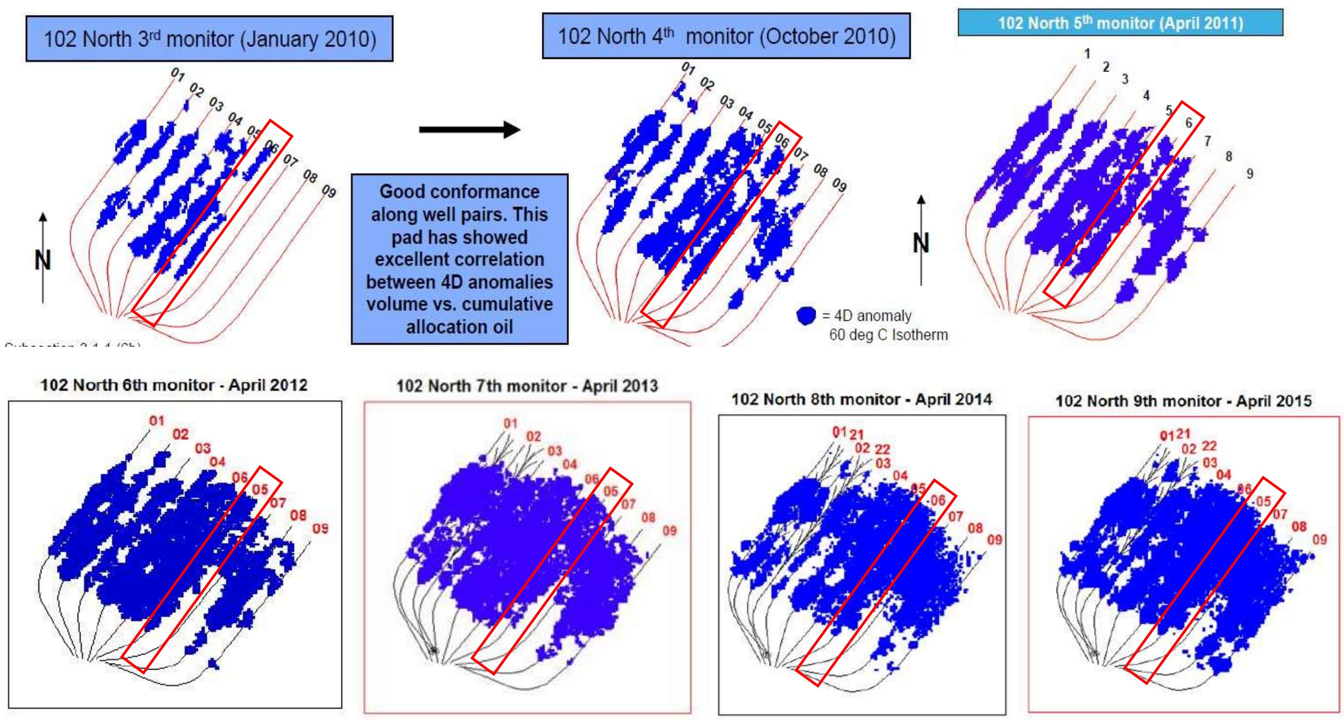

Figure 3: Composite image - Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentations to AER, 2011 through 2018
Note: Well 5 on Pad 102N has been labelled as Well 6 and vice versa in some of the company presentations

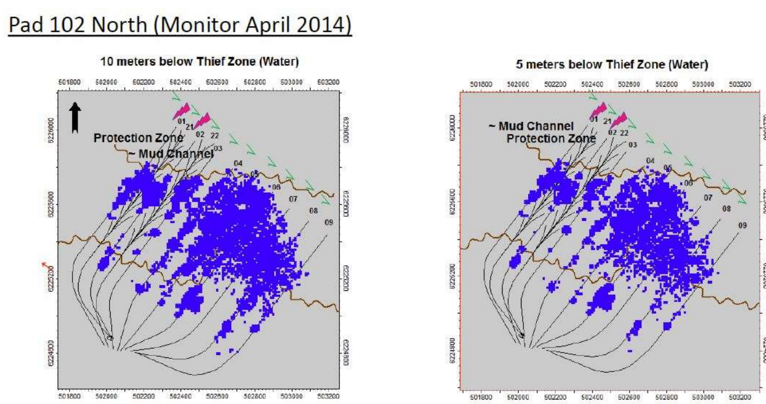

Figure 4: 4D Seismic anomaly at different elevations -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2015

Observations can be made on the 4D seismic plots of Pad 102N with particular reference to the well pair 06. Surprisingly, no significant difference in steam chamber conformance can be observed between non-FCD well pairs 04 & 05, and FCD well pair 06. Conoco claims that well pair 06 outperforms the other wells on the Pad 102N which are completed with a slotted liner. Because individual well pair performance is not presented, and in some seismic diagrams well pairs 05 and 06 are labelled interchangeably, makes this claim hard to verify (April 2012, 2013, 2015).

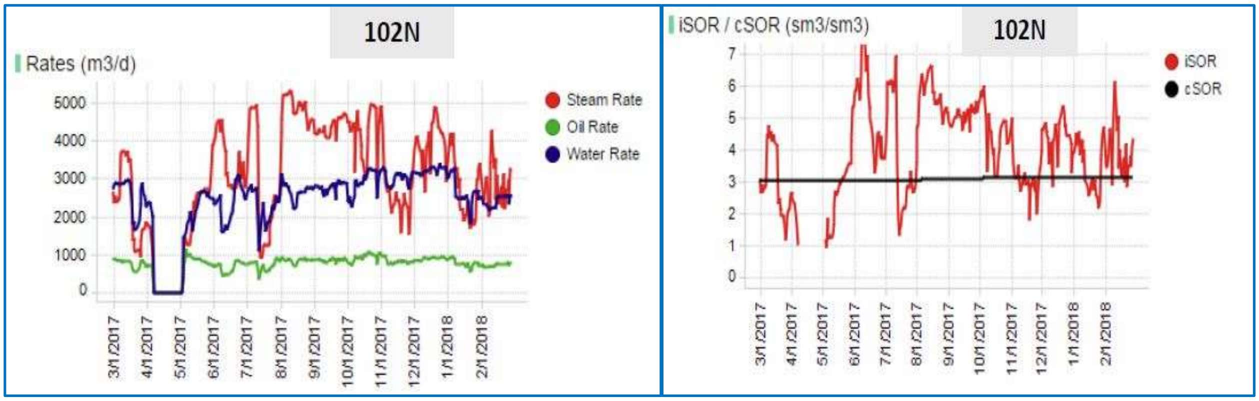

Figure 5: Production performance of Pad 102N -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

The author reviewed the current production of Pad 102 N (Figure 5), as well as historical D-54 presentations for Surmont Phase 1 and could not find any mention of well pair 06 as an example of a "High" producer. However in the 2016 presentation, Conoco reported another well on this pad (well pair 03) as an example of a "Low" producer. In the same presentation, well pair 08 is listed as an example of a "Medium" producer - there was no mention of well pair 06. Interestingly, the closest "High" producer (well pair 11 on Pad 102S) is a non-FCD well. The total production of Pad 102N seems to be approximately 900 m3/d in 2017 with an Instantaneous Steam Oil Ratio (ISOR) of about 4.5 and a Cumulative Steam Oil Ratio (CSOR) above 3, so Conoco will have to addresses these challenges to SOR. This pad also has two experimental "fishbone" inline wells, which presumably is an effort to tackle the SOR challenges.

In terms of Reservoir quality and Recovery Factor (RF), Conoco reported the following data for Pad 102N:

- Thickness of Net Continuous Bitumen (NCB) 31.14 m
- Effective porosity in NCB 32.71%
- Oil Saturation in NCB 80.29%
- Kh and Kv in NCB 4636 and 3877 mD
- Current RF 37.10%

Kh horizontal permeability, Kv vertical permeability

Pad 103 Surmont Phase 1

Pad 103 has similar reservoir characteristics to Pad 102N except pay thickness, as summarized below:

- Thickness of Net Continuous Bitumen (NCB) 42.80 m
- Effective porosity in NCB 32.21%
- Oil Saturation in NCB 78.62%
- Kh and Kv in NCB 4441 and 3691 mD

Figure 6 shows 4D seismic anomaly plots for Pad 103, which show some coalescence with the nearby Pad 101N. Longitudinal conformance seems slightly better in those well pairs equipped with FCDs (Well pairs 02, 03, 04, 05, 06, 08, 10 and 12), as compared to the non-FCD well pairs 01, 07, 09 and 11.

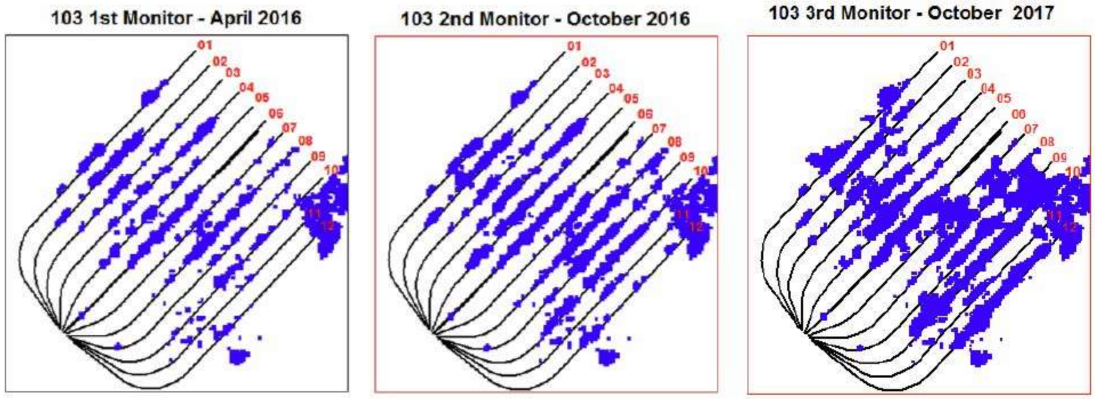

Figure 6: Composite image - Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentations to AER, 2017 through 2018

The production performance of Pad 103 has been good through 2017 with overall pad production in the range of 2,500 to 3,000 m^3/d, (Figure 7). Well pair 103-08 has been the most prolific producer on this pad with more than 350 m^3/d of bitumen at an ISOR below 2. It seems FCDs have been successful on this pad. However the net pay on this pad is the thickest amongst all Phase 1 pads, and there could be other reservoir characteristics that contribute to this performance. If individual well production, drilling, completion, and geological data were available for adjacent non-FCD wells, and those non-FCD wells were operated identically in terms of pressures, injection rates and sub-cool targets, only then could a conclusion be reached about the scale of improvement from FCDs alone.

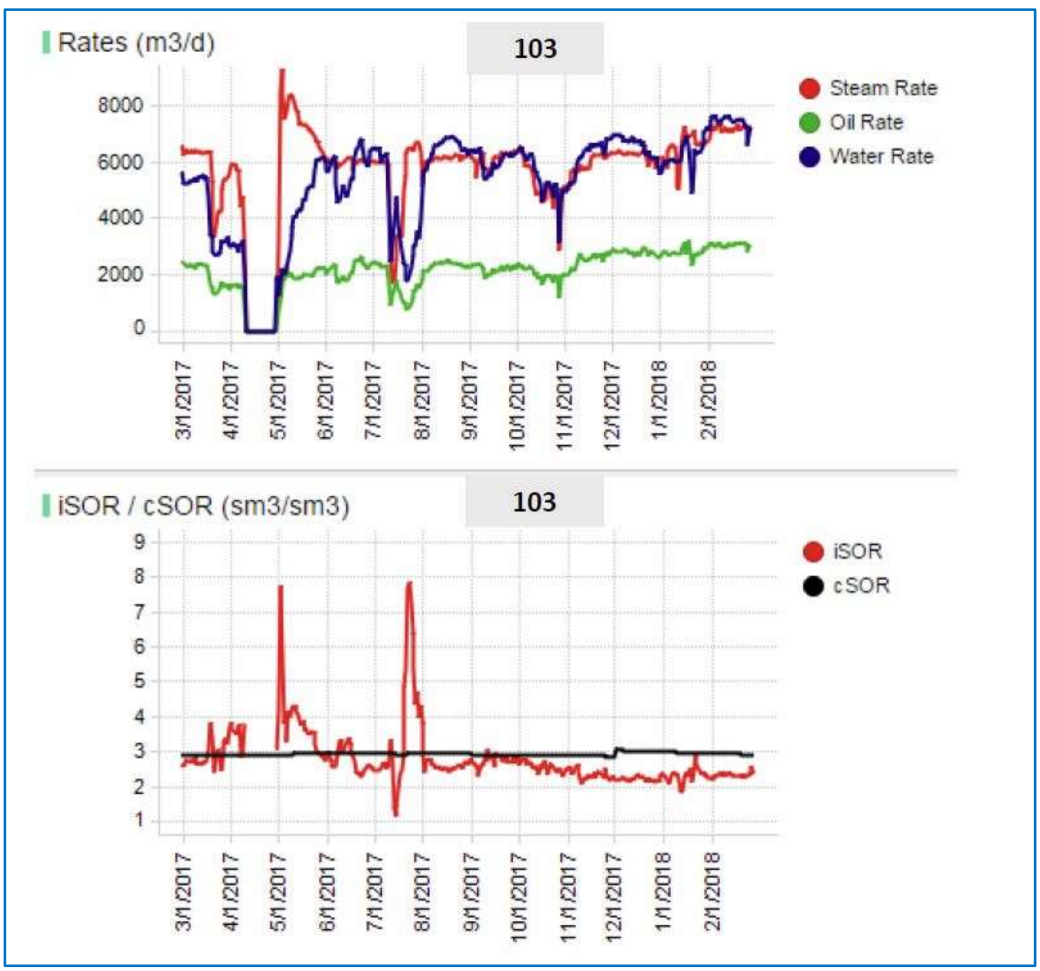

Figure 7: Production performance of Pad 103 -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

Pad 266-2 Surmont Phase 2

4D Seismic data is not available on Pad 266-2 yet, so we will contend with production data only. The reservoir properties of this pad are summarized below:

- Thickness of Net Continuous Bitumen (NCB) 42.99 m
- Effective porosity in NCB 32.83%
- Oil Saturation in NCB 80.08%
- Kh and Kv in NCB 4925 and 4121 mD

The way the charts are represented in the D-54 AER presentations, it is hard to gauge precise production numbers, but they seem less than 2,000 m^3/d for aggregate 12 well pairs, (Figure 8). This raises the question that if the overall thickness, porosity, saturation and permeability are better or comparable to Pad 103 presented above, then why is the 266-2 pad producing half the rate with the same number of wells?

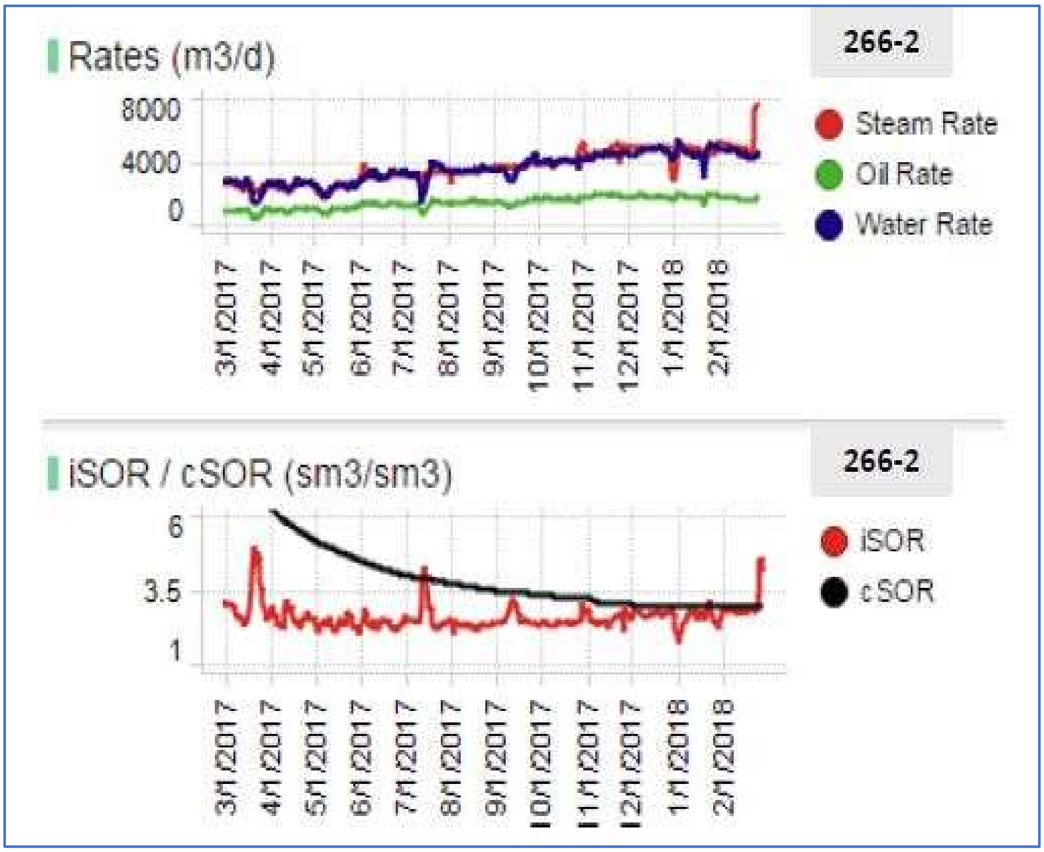

Figure 8: Production performance of Pad 266-2 -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

Could that mean the performance of a pad is less dependent on the FCDs but on other factors which are not in the public domain but can only be speculated? The SOR on this pad 266-2 seems higher than Pad 103, however it is still close to 3, a perfectly acceptable outcome for SAGD. The initial pressure on this pad is lower (1337 kPa compared to 1691 kPa on Pad 103) which may have introduced injection pressure and rate constraints. There is also a minor presence of top gas over this pad which lead us to believe that a conservative operating strategy may have been chosen.

Pad 263-1 Surmont Phase 2

The performance of 263-1 pad leads to some interesting observations, (Figure 9).

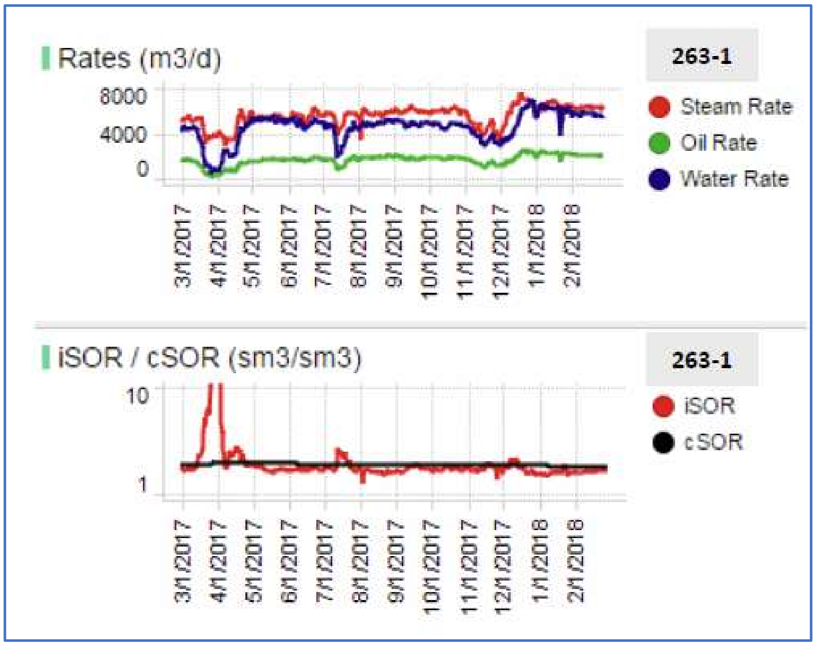

Figure 9: Production performance of Pad 263-1 -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

Aggregate bitumen production from the Pad 263-1 is in the range of 2,000 m3/d, with a SOR just over 3. The Reservoir parameters for this pad are as below:

- Thickness of Net Continuous Bitumen (NCB) 36.14 m
- Effective porosity in NCB 32.98%
- Oil Saturation in NCB 79.36%
- Kh and Kv in NCB 4966 and 4170 mD

The best performing well pair on this pad is 263-1-07 which shows good longitudinal conformance, with bitumen production rates of ~400 m3/d, and a SOR of over 2.5, (Figure 10).

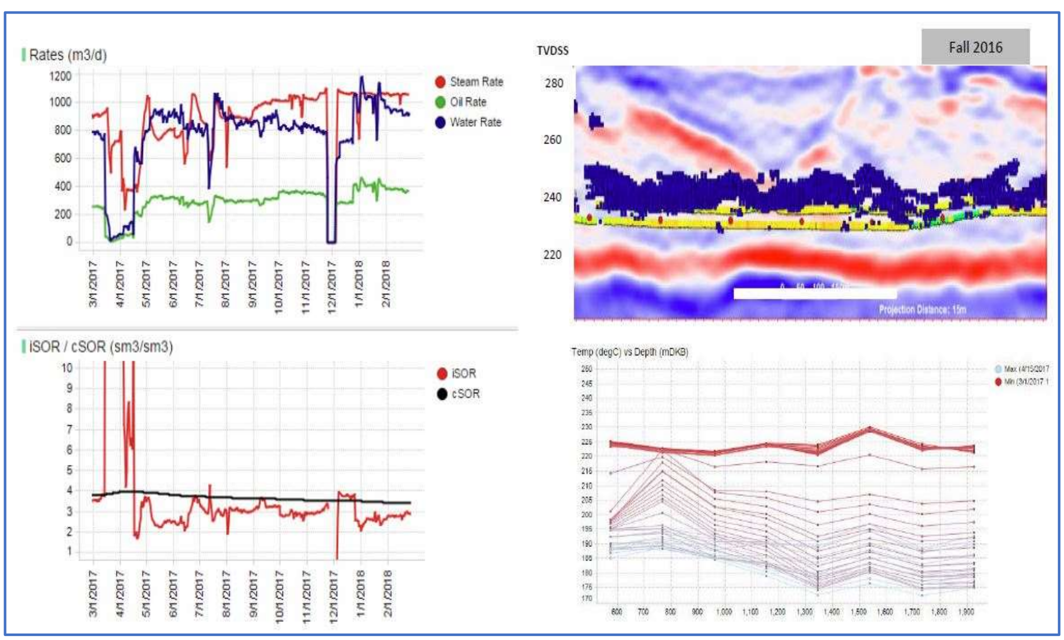

Figure 10: Performance of Well pair 263-1-07 -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

The offsetting observation wells' response, piezometric pressure and gamma ray plots are presented in Figure 11 for context:

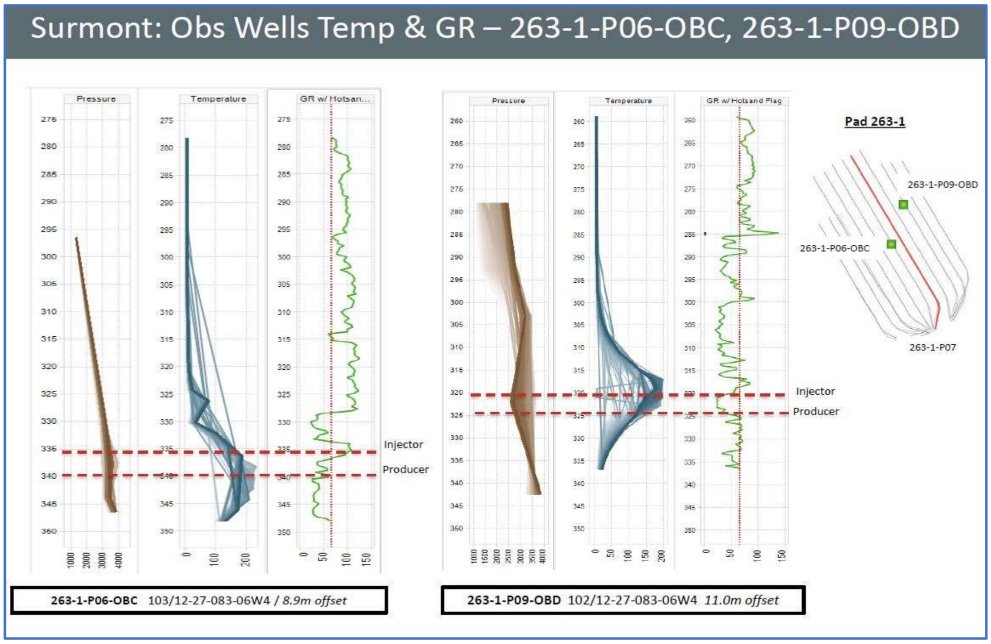

Figure 11: Pad 263-1 Observation wells -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

Some peculiar observations can be made from these Production and Observation plots. Water production seems to indicate water retention in the reservoir for some time and then in early 2018water production increased by almost 50%, while the steam injection rates were kept steady. This correlated with an increase in bitumen production from 300 m^3/d to 400 m^3/d and a drop in ISOR from 3.8 to 2.5. From the D-54 reports we cannot tell if this change was a function of reservoir, a change in operating strategy or some well completion event.

Another interesting observation is heating of the reservoir below the producer elevation in the Observation Well OBC, located 8.9 m offset from the midpoint of the well pair 263-1-07. The temperature is over 100 degrees C 8 m below the producer. If temperature measurements were available for deeper depths one could extrapolate that almost 10 m of reservoir below the producer elevation would be heated to 60 degrees C. If the temperature readings are correct this is unlikely to be the result of conductive heating alone.

Conoco mentions that the good performance of this well is due to FCDs and ESPs, however FCDs and ESPs are not unique to the well pair 263-1-07on Pad 263-1. There are 7 other wells on this pad with both FCDs and ESPs and 5 of these FCDs are liner deployed, similar to well pair 07. Also, the 4D Seismic shows no visible difference between conformances from one well pair to the next.

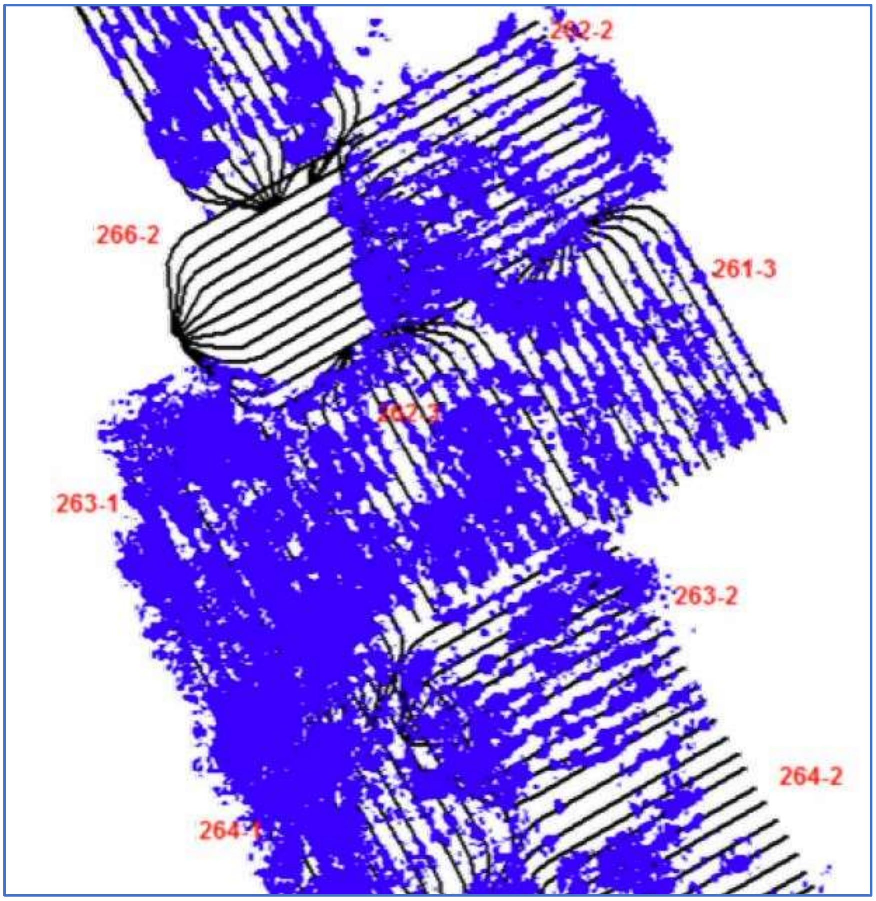

Figure 12: Surmont Phase 2 Seismic Monitor -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

4D Seismic (Figure 12), shows likely coalescence between Pad 263-1 and its southern neighbour Pad 264-1. One could even speculate that if the pressure in 264-1 were slightly higher than 263-1 the high water and bitumen production in Pad 263-1 was driven from Pad 264-1, as everything between the pads is mobile (>60 degC). There is some top water present over Pad 264-1 also.

Pad 264-3 Surmont Phase 2

The deployment of FCDs on Pad 264-3 is almost identical to that of Pad 263-1. However, the Pad 264-3 production performance is slightly worse than that of Pad 263-1. Aggregate bitumen production is about 1500 m3/d with a Steam Oil Ratio of about 3.5, (Figure 13). To bring context to the performance the general reservoir properties of Pad 264-3 are:

• Thickness of Net Continuous Bitumen (NCB)	37.51 m
• Effective porosity in NCB	31.97%
• Oil Saturation in NCB	75.58%
• Kh and Kv in NCB	4446 and 3683 mD

In comparison of Pad 264-3 properties to those of Pad 263-1, it is apparent that this reservoir, although thick, has slightly poorer quality. There is also some Top water and a Gas zone overlaying the reservoir in this pad.

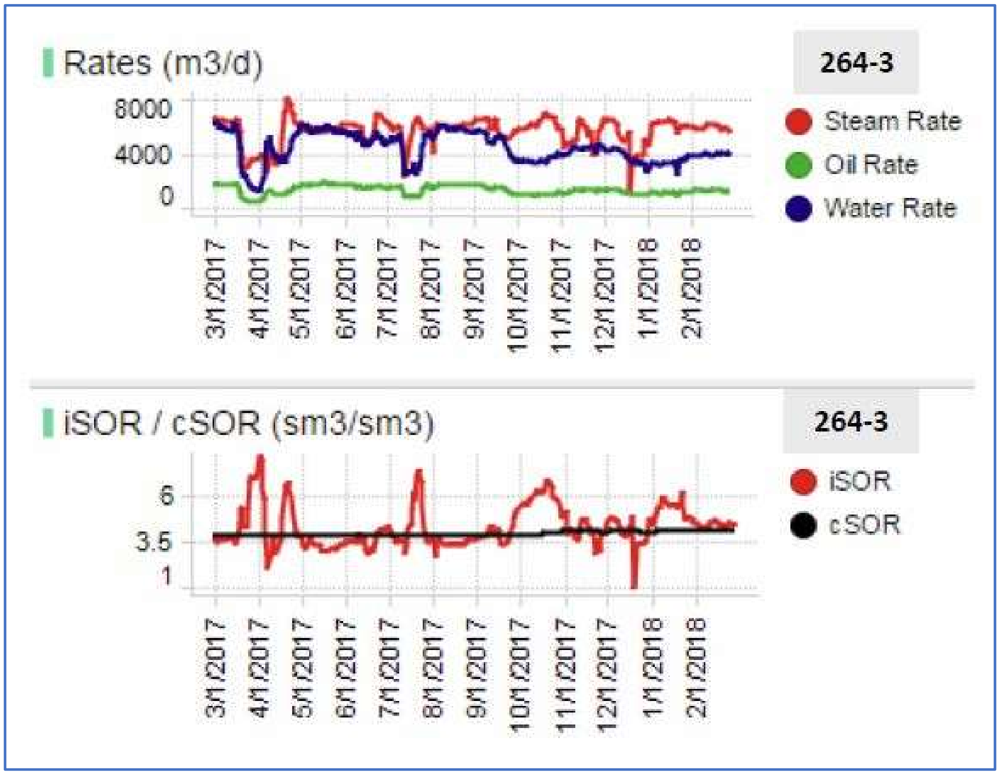

Figure 13: Surmont Pad 264-3 production performance -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

The 4D Seismic results show almost uniform longitudinal conformance over the entire pad, (Figure 14).

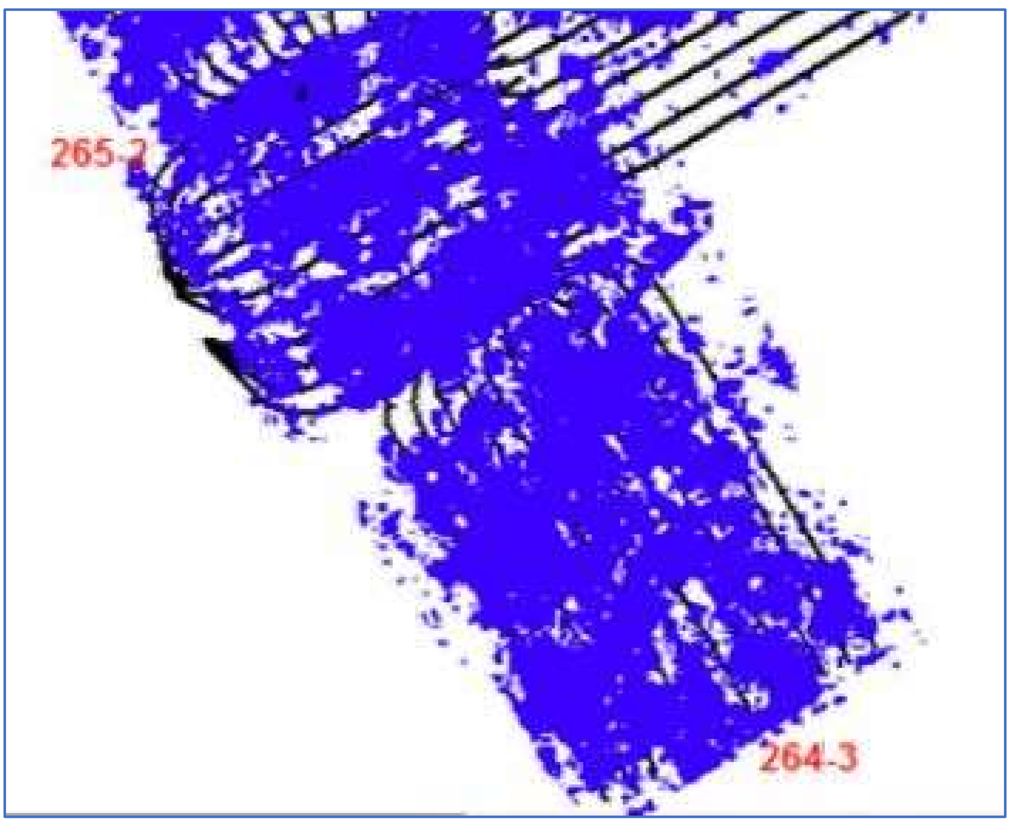

Figure 14: Surmont Phase 2 South Seismic Monitor -Source: Conoco Phillips, Annual Surmont SAGD Performance Review presentation to AER, 2018

Athabasca Oil Corporation (AOC) – Leismer Project

AOC has also been a strong user of FCDs, and perhaps the only other operator besides Conoco who has deployed FCDs on liners in some injector wells. The first pad to use FCDs was Pad L5, and subsequently Pad L6 and others. At the moment, AOC has 17 FCD installations, Figure 15 from their In-situ performance presentation:

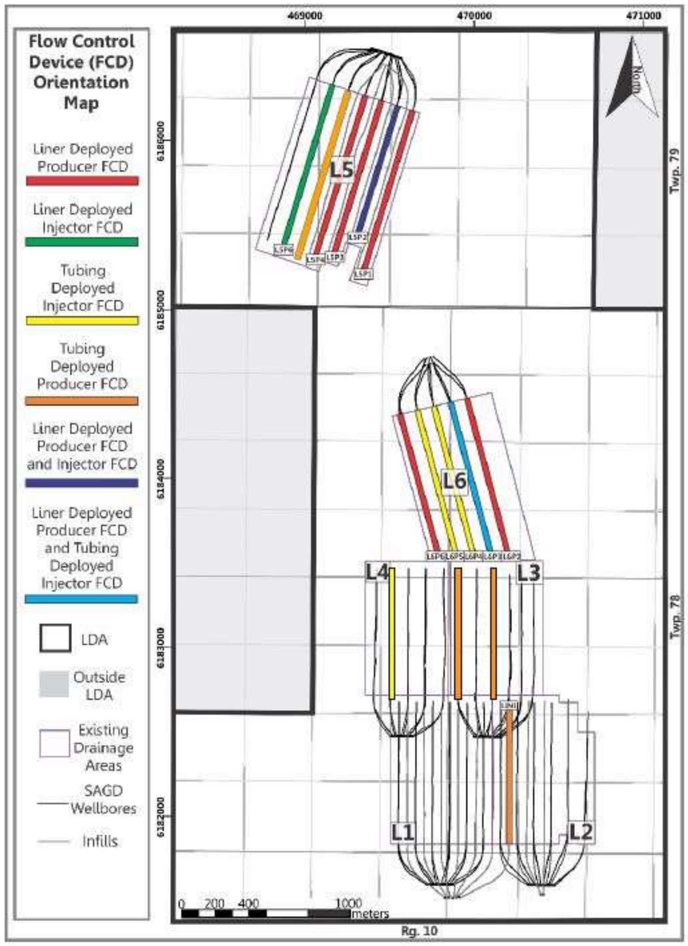

Figure 15: FCD Orientation Map -Source: Athabasca Oil Corporation, Annual Surmont SAGD Performance Review presentation to AER, 2018

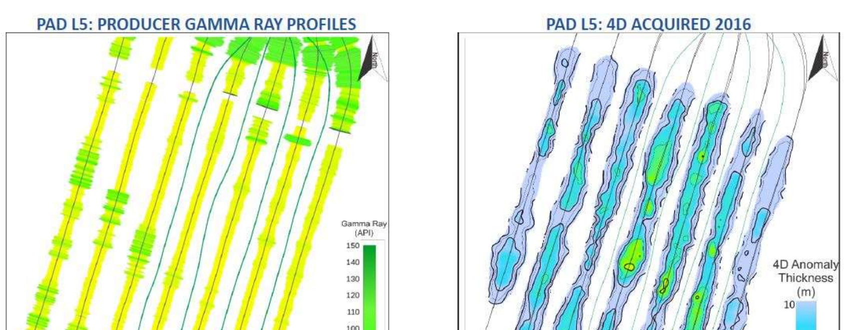

Figure 16: Pad 5 Gamma and 4D Seismic -Source: Athabasca Oil Corporation, Annual Surmont SAGD Performance Review presentation to AER, 2018

AOC's presentation of 4D Seismic is quite insightful as it presents the two-dimensional location of the anomaly corresponding to the 60 deg C isotherm, and also the thickness of the anomaly, which can be interpreted as the height of the steam chamber, (Figure 16). Pad 5 shows a high degree of longitudinal conformance for well pairs 1 through 4 which are all equipped with FCDs. The Gamma plots in the SAGD producers show cleaner sands in the same well pairs 1 through 4. AOC has reported increasing Breccia above the producer elevation in well pairs 5 through 7, therefore it is hard to attribute the SAGD steam chamber conformance to either FCDs or the Reservoir alone. The prudent assumption is Geology and Reservoir quality are more dominant factors in a well's performance than Well Completions.

No discussion of conformance can be meaningful if not translated into production results. The aggregate Pad Production and ISOR plot is shown in Figure 17 below:

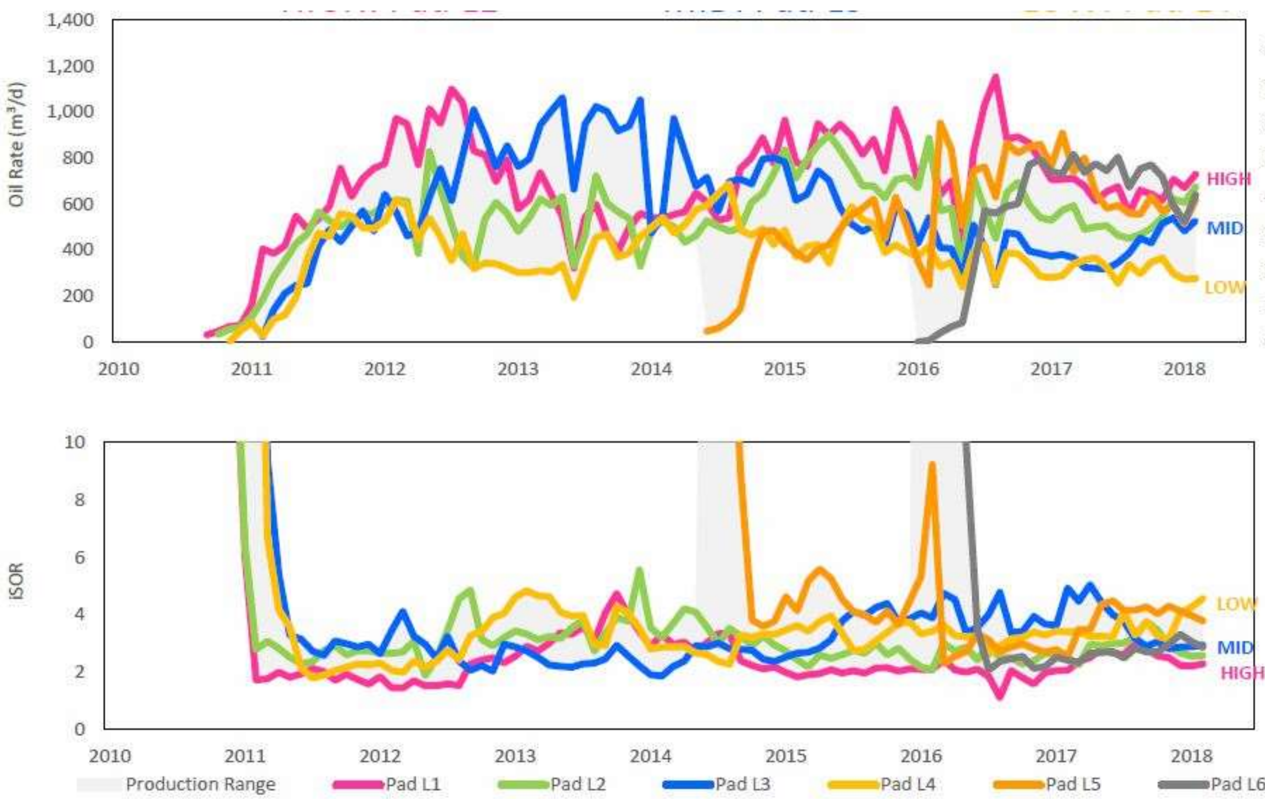

Figure 17: Leismer Pad Production -Source: Athabasca Oil Corporation, Annual SAGD Performance Review presentation to AER, 2018

Production from Pad L5 (orange line) can be estimated as somewhere between 500 to 600 m3/d, with an SOR between 3.5 and 4.0. This pad does not have a very thick pay (17.6 m) and also has an uneven ceiling which makes even steam chamber development challenging. This pad also has a small amount of bottom water.

<u>Southern Pacific – McKay River Thermal Project</u>

This project has been in dire straits almost from the start and had been mothballed till recently. Last year, it was been taken over by a private corporation and there are chances that it may be restarted. This project was the perfect example of trying to solve Reservoir quality and drilling related issues through well completions. Initial results from the FCD recompletions were encouraging but unfortunately did not result in the step-change hoped for.

Southern Pacific presented a summary of their FCD installations in a scorecard as part of their in-situ performance presentation made in 2015, reproduced below in Figure 18:

WELL	INSTALLED	OIL RATE IMPROVEMENT?	INCREASED DIFFERENTIAL?	iSOR IMPROVEMENT?	HOT SPOT CONTROLLED?
2P1	January 2014	YES	YES	NO	YES
1P5	February 2014	YES	YES	YES	N/A
2P5	June 2014	YES	YES	NO	YES
2P2	September 2014	NO	YES	NO	YES
1P2	October 2014	NO	YES	NO	YES
1P6	October 2014	NO	YES	NO	YES

Figure 18: ICD Scorecard -Source: Southern Pacific Corporation, Annual SAGD Performance Review presentation to AER, 2015

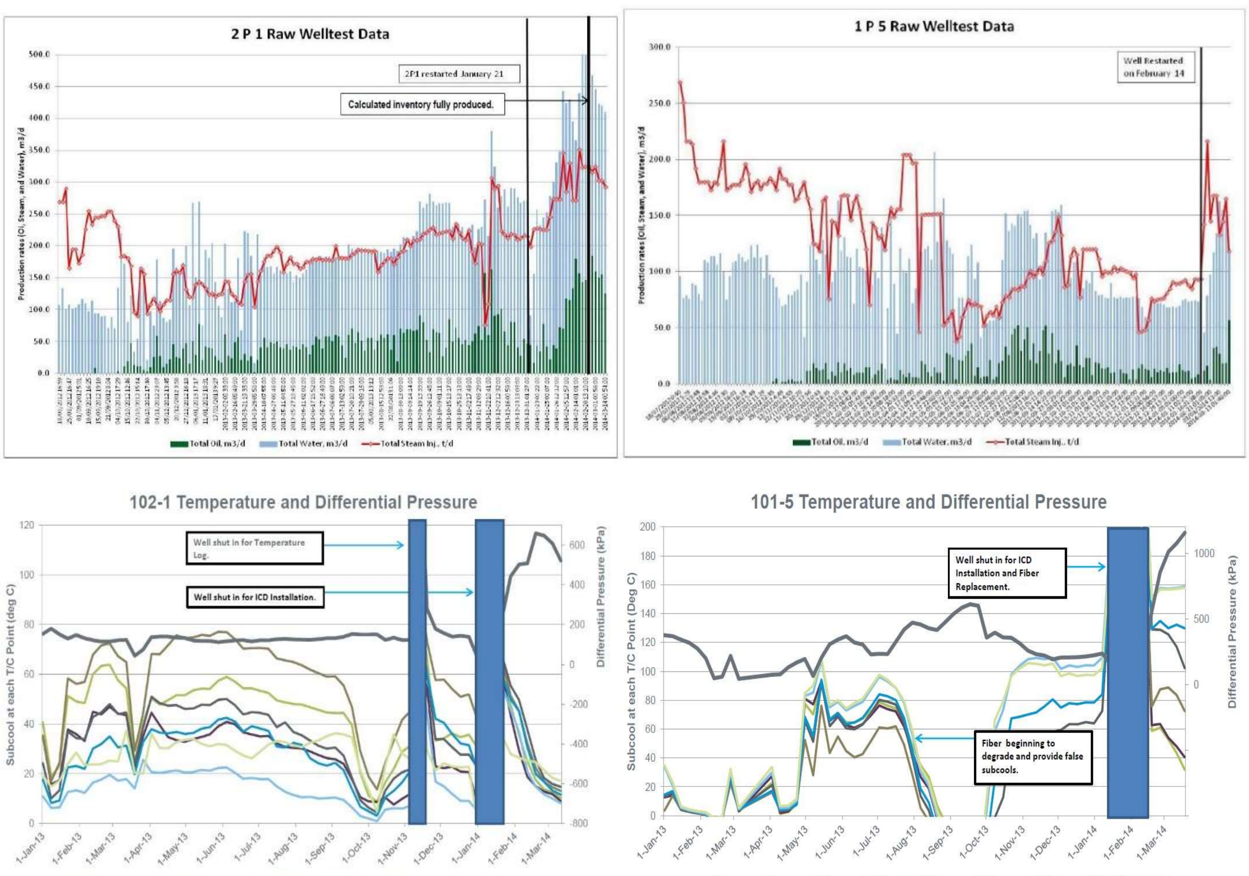

Figure 19: 2P1 and 1P5 ICD results -Source: Southern Pacific Corporation, Annual SAGD Performance Review presentation to AER, 2014

There was production improvement at the 2P1 producer immediately after ICD installation, whereas on 1P5 improvement was marginal. It is hard to establish from the temperature and differential pressure plots whether the stated objectives for ICDs in terms of conformance were met, due to complications of unreliable fibre data due to degradation.

Devon - Jackfish Project

Devon has deployed Inflow Control Devices on 5 producer wells of its Jackfish Project. Three wells (CC1P, DD2P, and DD7P) have tubing deployed devices, while two (RR2P and RR6P) have liner deployed devices.

The average Reservoir properties on these pads are presented in the table below:

Pad	Gross Pay (m)	Net to Gross %	Oil Saturation %	Porosity %	Average Kh (mD)	Average Kv (mD)	Original Reservoir Pressure (kPa)
CC	29	90	73	34	3000	1200	2700
DD	34	90	79	34	3000	1200	2700
RR	32	91	82	34	4000	1500	2700

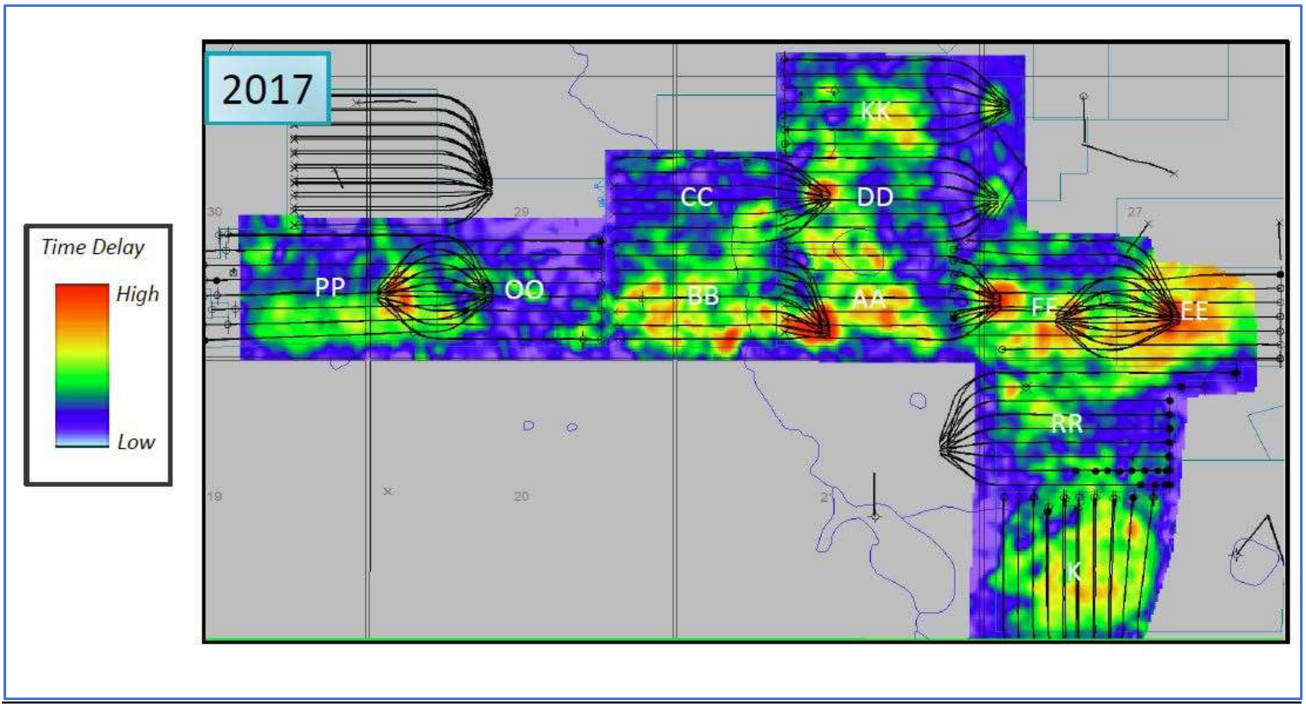

Figure 20: Jackfish 2 and Jackfish 3 4D Seismic Interpretation -Source: Devon, Annual SAGD Performance Review presentation to AER, 2017

Devon's 4D Seismic, (Figure 20) shows poor steam chamber development and low conformance over the areas of Pads CC, DD, and RR where ICDs are installed. Devon's general comments on ICD performance, and specific comments on Pad DD are extracted from the D-54 presentation as below:

- Tubing-deployed systems on wells CC1P, DD2P, and DD7P
  - Installed successfully via service rig
- Liner-deployed systems on wells RR2P and RR6P
  - Installed successfully via drilling rig
- Performance measured through sustained production uplift
  - Sustained uplift yet to be observed on tubing deployed systems
  - Evaluation of liner deployed systems ongoing, learnings will be incorporated in future ICD design
- Key learnings were:
  - Actual pressure drops through ICDs different than designed
- Inflow Control Device installed in September 2013 (DD2); well achieved expected production with period of flush production
- Inflow Control Device installed in November 2014 (DD7); under-performing pre-installation rates, likely due to ΔP higher than anticipated in design

Conclusions

The author has drawn some insights and conclusions from all the data presented above:

1. It seems there is a consensus in the industry that Flow Control Devices and other completion techniques such as Vacuum Insulated Tubing are important for enhancing performance, and the FCD technology is mature enough for wider adoption.

2. For SAGD injectors, it appears that liner deployed FCDs have not provided any significant advantage over Steam Splitters. Therefore, Steam Splitters in injectors seem to be the cost-effective way to achieve better steam distribution than a plain slotted liner. More than half of the wells enumerated in Figure 1 are injector wells equipped with Steam Splitters on tubing.

3. FCD and other well completion techniques are only one factor among several determinants of a project's performance. The other important factors are: Reservoir thickness, Reservoir quality in terms of clean sand and vertical permeability, viscosity at original reservoir conditions, presence/absence of thief zones, Reservoir pressure, limited occurrence of severe heterogeneities, and well placement.

4. Another crucial factor is the operating strategy, particularly sub-cool and operating pressure, which can produce significantly different results. The author noted that in several SAGD projects, sub-cool of up to 20 degrees C is common, with extreme cases having sub-cool in excess of 40 degrees C. Such high sub-cool values will, and have drastically lowered production rates on such projects. Interestingly, even wells equipped with FCDs are being operated at a sub-cool of 10 degrees C by many operators.

5. FCD testing is complex and should be particular to each Reservoir type and operating conditions. However, most operators do not invest the time and capital in this effort. Thus, the expected Flow Resistance Rating or the Pressure drop which was anticipated in the design stage is not often realized in actual operations. Adequate margins of operating conditions must be chosen when designing FCDs for a particular application, otherwise there would be disappointing surprises.

6. Even with the state-of-the-art directional drilling, geo-steering and ranging systems, there are often large uncertainties and errors in well placement which may be outside the capabilities of Flow Control Devices to correct.

7. It is indeterminate whether Liner deployed systems in SAGD producers are more effective than Tubing deployed. Results in terms of KPIs suggest that both ways work where properly designed and executed, and where there is a real need. Where adverse conditions, natural or self-inflicted, are insurmountable then neither will work. The advantage of tubing deployed system is better risk management. If an operator has gained enough knowledge of the reservoir and all indications are towards more consistency and homogeneity in new wells, then liner deployed systems will have the advantage of larger size and corresponding larger rates. The cost of these liner deployed devices has also come down significantly to justify intensive use in conjunction with blank liner pipe.

8. A similar argument holds true for FCD retrofitting versus incorporating FCDs in design from day one. Risk management dictates that adequate Reservoir knowledge is gathered, and performance is observed for a reasonable period before a custom-designed solution is introduced.

9. Conformance alone is not the best measure of FCD performance. For all FCD equipped wells, adequate criteria must be established which must include oil production, water production, steam oil ratio, sub-cool, pressure drop, temperature distribution in the producer, and Observation wells' data.

References

In situ performance presentations (2011 through 2018):

https://www.aer.ca/providing-information/data-and-reports/activity-and-data/in-situ-performance-presentations

About the author:

Harris Naseer, P.Eng., has been involved with oil and gas industry for over 22 years. He started his career with Schlumberger in 1996 and moved to E&P operations in 2004. He has been actively engaged in Heavy Oil and Oil Sands for more than 10 years and is considered one of the leading reservoir and production specialists in thermal recovery. Harris is currently the General Manager Subsurface for Tallahassee Exploration Inc. He is a volunteer member of the CHOA editorial committee and has contributed cover articles for a number of issues for the CHOA Journal.