Considerations for the Application of ±800 kV HVDC Transmission From a System Perspective

Bruno Bisewski & Rao Atmuri

Teshmont Consultants LP
1190 Waverley Street
Winnipeg, Manitoba
Canada, R3T 0P4

www.teshmont.com

1. Introduction

The highest voltage dc system in commercial operation today is the Itaipu transmission which has been in service for over 15 years at ±600 kV. Transmission at voltages up to ±800 kV dc is considered to be possible without significant development on major equipment [1][2]. This voltage level is considered necessary for the transfer of 5000 MW to 6000 MW per bipole over distances of 2000 to 2500 km. To transfer the same amount of power, using the highest commonly applied ac voltage, two 800 kV ac lines with a number of intermediate stations would be required. The choice between the ac or dc transmission is a techno-economic analysis with right-of-way and the availability of reliable equipment as additional factors.

Based on past performance, making the step to the higher voltage and power will undoubtedly result in a new set of challenges and possibly problems. Even without new challenges there are a number of issues that have already been identified as requiring further discussion and analysis prior to application of HVDC at ±800 kV. Many of these issues have been identified in the workshop invitation, and are as follows:

- Impact of transient and permanent outages of very large power blocks on the ac systems
- Large physical size leading to transportation difficulties
- Selection of suitable insulation levels and margins especially for transformers
- Outdoor insulation in substations and lines especially in polluted areas

This paper looks at the implications of these known technical difficulties from a utility perspective and looks at ways in which the risks or impacts can be limited to acceptable levels.

2. Impact on the AC Systems

Transient or permanent interruption of the dc power on a pole or bipole can have serious consequences for the ac systems where the terminals are connected. The problems are well known from HVDC systems at lower voltage and power levels, but become generally more difficult as the power levels are increased.

The major impacts to the ac systems when the HVDC is suddenly lost include overvoltage, and frequency variation.

Overvoltages are generally easier to handle in that they can be readily relieved by tripping of an excess of shunt connected reactive sources or by installing overvoltage control and limiting equipment such as SVC's, STATCOM's or synchronous condensers.

Frequency variation is more difficult to handle as it can usually be overcome only by load shedding or by adding a significant amount of system inertia. This is an unpleasant prospect for utilities as their mandate is to provide continuous uninterrupted supply.

The magnitude of the frequency variation expected following permanent loss of infeed is a function of:

a) magnitude of the loss of power infeed,
b) the connected load in the system,
c) load reduction due to frequency drop
d) overall inertia of the system including spinning reserve,
e) permitted overload of the remaining valve groups

A parametric analysis was carried out to illustrate the impact of these factors for a ±800 kV, 5000 MW bipolar HVDC system feeding into an ac system with 10000 MW of connected load. The analysis was performed for three circuit configurations:
a) one 2500 MW valve groups per pole
b) two 1250 MW valve groups per pole
c) three 833 MW valve groups per pole

The expected frequency drop versus time for a given loss of infeed is shown in Figure 1. In Figure 2, the final frequency drop is shown as a function of the total load connected in the system.

The dc system was assumed to have been operating at rated output prior to the disturbance and it is assumed that there is no spinning reserve available to pick up load. The system load reduction due to frequency drop depends up on the characteristics of the load being served and it is assumed to decrease by 2% for every 1% reduction in frequency.

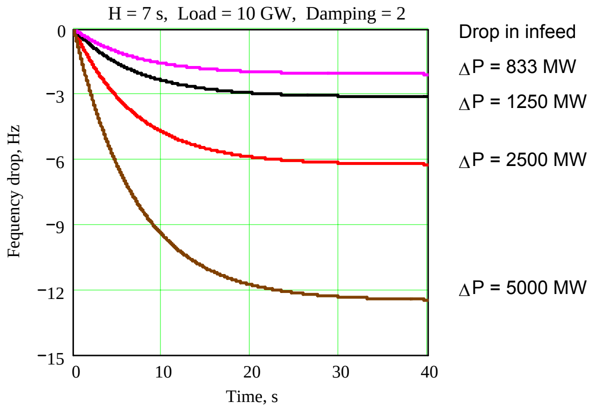

Figure 1
Frequency Drop vs Time as a function of loss of infeed for a System with 10 GW of Load

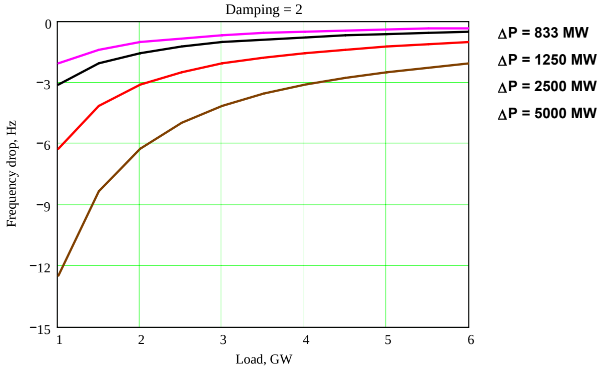

Figure 2
Frequency Drop as a Function of Loss of Infeed ΔP and System Load

Historically there have been about 5 forced outages per valve group per station per year. This would result in about 20 valve group forced outages per year for a bipole with one valve group per pole. The transmission capacity reduction during each pole outage would be 2500 MW. With two valve groups per pole the number of forced outages would be about 40 but the capacity lost would be only 1250 MW. With three valve groups per pole the number of forced outages would increase to 60 and the lost capacity would reduce to 833 MW. As some valve group outages could escalate to pole outages the system would need to be designed to withstand loss of a pole regardless of the number of valve groups per pole.

These figures illustrate that in order to limit the frequency disturbance to a value that can be tolerated (say 3 Hz) the size of the dc pole (ΔP) should be no more than about 1/8 of the total connected load in the system. If the magnitude of the infeed exceeds this value then it may be necessary accept a larger frequency variation, or if this is not possible, to shed a large amount of load. As the tripping is generally done by monitoring the frequency and rate of change of frequency, the amount of load that needs to be shed would exceed the amount of the loss of infeed by a large margin.

If there is more than one HVDC system bringing power into a system which could be affected at the same time, then the impact in terms of load shedding would be even more significant.

The amount of load shedding needed for pole or valve group outages can be significantly reduced if the equipment remaining in service can be operated at a significant overload for some time until emergency generation can be brought on line.

It should not be assumed that any appreciable amount of short-time overload capacity would be inherently available in an ±800 kV or for that matter any HVDC system. For example, a thyristor, with a 4 kA current carrying capacity might provide 1.28 pu overload capacity on a 5000 MW, ±800 kV bipolar system but would have very limited overload capacity if the rating of the bipole is 6000 MW.

In a competitive environment, the lowest cost will result if the equipment, especially relatively high-value, high-parts-count items such as the thyristors are operated to their maximum ratings. The optimization process provides an incentive to use of the highest voltage thyristors to reduce the parts count. There may be tradeoffs between thyristor voltage and current ratings and there could be reduction in thyristor maximum current ratings as voltage rating of the thyristors increases. This could limit the opportunity for overload operation.

To avoid difficulties the optimal amount and duration of dc system overload capacity should be determined and specified prior to going out to bid. Significant levels of overload would increase costs and would have an impact on the design possibly to the extent that the supplier cannot follow the recent trend to the use of off-the-shelf thyristors and would need to supply a unique design instead.

Figures 1 and 2 are derived for the receiving systems. In the sending systems the frequency variations would generally be larger as the amount of connected load would be expected to be smaller. This could be overcome by generator tripping. Generator tripping would however preclude the rapid re-energization and restart of the HVDC system.

3. Number of Valve Groups per Pole and Choice of Transformer Configuration

Considerations of the impact on the ac systems as discussed above together with transport limitations or restrictions on size and weight of equipment, particularly converter transformers will be the primary factors considered in determination of the configuration of the dc circuit of an 800 kV HVDC transmission system.

In the initial years of HVDC development, a number of systems were constructed with two or more series connected valve groups per pole. The reasons for building more than one valve group per pole were generally related to equipment ratings especially with mercury-arc converters and to considerations of impact of loss of infeed to the receiving systems.

As ac system capacity has continued to grow, the question of system impact due to loss of infeed has become less of an issue and the trend in recent years has been to build HVDC systems with only one 12-pulse valve group per pole with ratings to 1500 MW pert pole. This results in the most simple and reliable, as well as the least costly configuration.

With the advent of 800 kV systems, the question of loss of infeed may again become significant as the rating of a 2500 MW pole will be significant in ac systems having connected load lower than about 20 GW.

Increasing the number of valve groups per pole increases the cost and operational complexity of the system and could be avoided if the ac systems are robust enough to withstand loss of a complete pole. Assuming this is the case, the circuit configuration may be governed by limits on transportation size and weight.

A rough indication of transformer transportation weight is given in Figure 3. The information in the figure was originally compiled by ABB and has been found to coincide reasonably with available information from other suppliers on other projects. For each of the transformer options the weight per transformer varies within a range depending on the ac side and dc side voltage ratings.

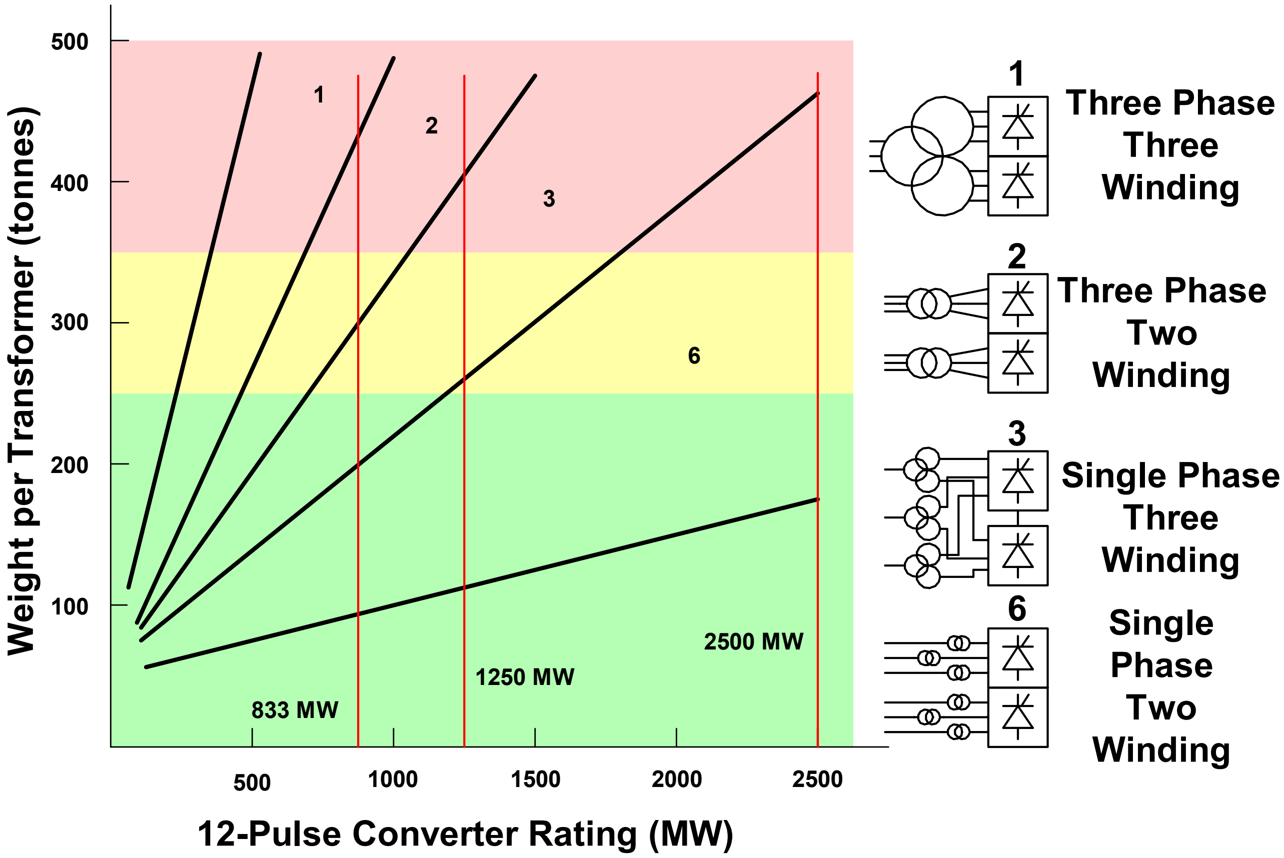

Figure 3
Range of transformer Transport weights for Different Transformer Configurations

Table 1
Transformer Rating per 12 pulse Valve Group

VG per pole	Valve Group Rating		Total Transformer Rating per Valve Group (MVA)			
	kV	MW	Three-Phase		Single-phase	
			3 winding	2 winding	3 winding	2 winding
1	800	2500	1x2939	2x1469	3x980	6x490
2	400	1250	1x1469	2x734	3x490	6x245
3	267	833	1x980	2x490	3x326	6x163

Note: Transformer MVA rating is calculated with 15% reactance and α of 15º.
Magenta shading denotes transformer too heavy to transport
Yellow shading denotes transformer weight may make transportation difficult.
Green shading indicates transformer weight within manageable limits.

The valve group DC voltage, MW and total transformer ratings for a 5000 MW Bipole with one two or three valve groups per pole are shown in Table 1.

From an economic point of view, a single 2500MW 800kV 12-pulse valve group per pole would be the cheapest. This configuration is also the simplest and easiest to operate. However, transformer transportation limits would effectively eliminate the single valve group option for all but the most accessible sites. Transformer weights even with single phase two winding transformers are expected to be in the 350 to 400 tonne range.

Two twelve-pulse valve groups per pole each rated at 400kV, 1250MW could be realized, however, this configuration may not be optimal as it results in a large power reduction and high losses when one valve group is out of service. Even with two valve groups per pole, the transformer weights will still be substantial and would generally restrict the winding configuration to single phase two-winding transformers which would be in the 250 tonne range. Single phase three winding transformers would be in the 350 to 400 tonne range and could be impractical in most cases.

Three valve groups per pole seems to provide a logical compromise between operational complexity and performance. With three valve groups per pole the voltage and power transfer capability when one valve group is out of service are 2/3 of the design level. This is significantly better than two valve groups per pole. With three valve groups per pole, single phase three-winding and single phase two-winding transformers may be possible. The single-phase three winding is the preferred option if weights approaching 300 tonnes can be transported. The single phase two-winding option results in 18 transformer units per pole, compared to 9 units with the single-phase three winding option.

4. **Transformer Valve Winding Insulation Levels**

In steady state, the valve winding of a converter transformer is subjected to a complex combination of fundamental and harmonic frequency component voltages in addition to dc voltage as shown in Figure 4. This figure is taken from Electra May 1976 and was determined for a 500 kV system and clearly shows the voltage jumps due to commutation [3]. The voltage steps would be larger for an 800 kV valve group. This voltage waveform with multiple sharp jumps per cycle will be present all the time. It may be noted that at present there exist no tests defined in the transformer standards to test the ability of the transformer to withstand these waveforms.

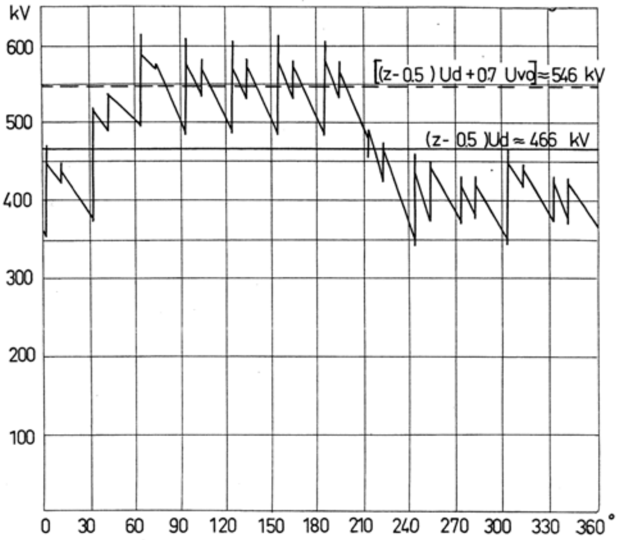

Figure 4
Voltage Waveform on Transformer Valve Winding

Transiently, the transformer valve winding may be subjected to switching surge waveshapes transferred from the ac side or steep front waveshapes due to faults. The valve winding side of the converter transformer would not be subjected to lighting surge waveshapes, as it would be within the valve hall where voltages with lightning waveshapes cannot occur. Steep front voltage waveforms would occur only in the event of faults within the valve hall and would be rare.

The converter transformers are specified to withstand switching, lightning, steep front, chopped wave, voltage reversal and dc voltages. The IEEE and IEC standards have defined procedures for transformer testing. But, these procedures do not test the transformer to the actual voltages to which it is going to be subjected over its life cycle.

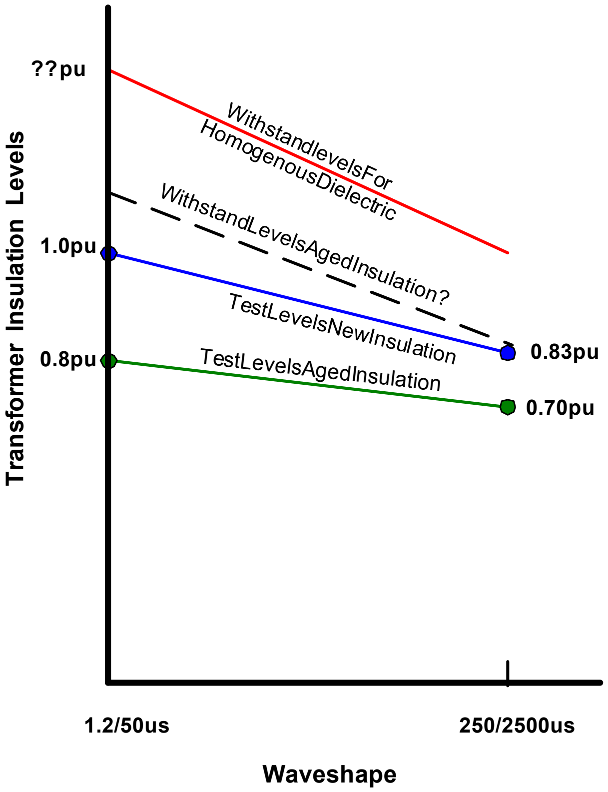

Figure 5
Transformer Insulation Withstand Levels

Transformers are expected to be reliable and available for operation for a period of 25 to 30 years. The insulation has to withstand the mechanical, electrical, ambient and aging effects over its life span and not just the factory tests or completion of the warranty period.

Figure 5 shows typical transformer insulation levels and illustrates the concept of margin between the test levels and the withstand capability. The blue line shows the test levels at standard switching and lightning waveshapes with linear interpolation in between the two. The red line indicates the actual withstand of the winding insulation structure based on homogeneous dielectric. This represents the designer’s margins to take care of unknowns such as the effect of non-linear field distribution, manufacturing tolerances, temperature dependence of insulating materials, effect of aging etc. The margin provided depends upon the supplier’s manufacturing practice and the confidence level in the design procedures.

Aging is known to reduce the withstand capability of transformer insulation. This has the effect of eroding the designer’s margin as shown by the dotted black line. The withstand levels of the aged insulation may fall below the original test levels and it is common practice to test the insulation of a used transformer at no higher than about 80% its original test values as indicated by the green line.

Table 2
Insulation Levels of Highest Bridge Transformers
For HVDC schemes With voltages Above 500 kV

Project	**DC Voltage (kV)**	**LIWL (kV)**	**SIWL (kV)**	**SIWL / LIWL**
Rihand – Dadri	500	1550	1290	0.83
Intermountain	500	1550	1290	0.83
Quebec – New England	500	1425	1300	0.91
Gezhouba - Shanghai	500			
Tian - Guang	500	1550		
3 Gorges (Longquan)	500	1675	1425	0.85
3 Gorges (Zhengping)	500	1675	1300	0.78
3 Gorges – Guangdong	500	1675	1425	0.85
Guizhou – Guangdong	500			
Talcher – Kolar	500			
Chandrapur - Phadge	500	1550	1290	0.83
Itaipu	600	1800	1500	0.83
EPRI	800	1950	1800	0.92
CIGRE	800	1990	1891	0.95

The process of selecting insulation levels of the valve side of a converter transformer is fundamentally different than the process of selecting the insulation levels of an ac transformer.

The transformer switching impulse protective level on the valve side is calculated from the thyristor valve insulation coordination. The withstand level is obtained by multiplying the protective level with protective margin. The procedure is well documented in the literature including the IEC TS 60071-5 [4].

The determination of the lightning impulse withstand level is not explicitly defined but in most HVDC systems to date has been selected to be the standard LIWL value close to 1.2 times the switching withstand level as shown in Table 2. Thus it has been common practice to maintain the ratio of the SIWL to LIWL for the valve side windings the same as on the line side.

For the Hydro Quebec/New England system the above practice was not followed and instead the LIWL was selected as 1425 kV, which is only 1.10 times the 1300kV, the calculated SIWL value.

In the CIGRE Working Group document [5] the LIWL is selected simply by dividing the SIWL value by 0.95 without stating any reasoning for departing from the common practice.

Given the fact that we have little information on the designer's margin and the deterioration of insulation with age are we ready to go to a new higher voltage level and lower LIWL to SIWL ratio? Can we afford these two steps in one go, especially when a transformer failure is going to affect extremely large blocks of power?

The experience for 800kV ac transmission provides a strong indication that lowering the BIL could result in increased numbers of failures and outages and should be avoided until sufficient design, manufacturing and operating experience is gained.

Until such time it is not considered appropriate to lower the LIWL to SIWL ratio. We feel that continuing to use the traditional value of 1.2 as the ratio between LIWL and SIWL is appropriate.

5. Outdoor Insulation

Station Insulation

Pollution flashovers are a known concern with HVDC and can have a significant impact on performance. This issue can be regarded a fundamental problem for HVDC and a number of possible solutions have been attempted with varying degrees of success:

- Periodic hand cleaning
- Automatic washing
- Increased creepage length
- RTV coatings
- Greasing with silicon grease
- Silicon Rubber insulators
- Indoor HVDC switchyard

These methods, alone or in combination, are likely to be sufficient to provide satisfactory operation at 800 kV.

Transmission line insulation

The dc transmission lines at and above 500 kV have been designed with specific creepage distances varying from about 20.4 mm/kV to 41.6 mm/kV depending up on the pollution level as shown in Table 3. These lines have been fitted, initially with porcelain or glass insulators. Insulator flashovers have been reported due to pollution and wetting caused by humidity and fog [6] [7].

Mitigation methods such as application of silicone grease and RTV coating, hotline washing, reduced voltage operation, increasing creepage distance and replacement at regular intervals have been practiced with varying degrees of success.

In China utilities are replacing the porcelain and glass insulators with silicone rubber insulators on their 500 kV HVDC lines and are reporting greatly improved flashover performance. The performance seem to hold even with reduced creepage distances roughly corresponding to ¾ that of porcelain insulators [7]. Premature aging could be a potential problem especially under polluted conditions and needs to be closely monitored.

Flashover performance of line insulators is a concern at 800 kV due to greater effect on the ac system and composite insulators could be a potential solution, especially in polluted areas. Periodic cleaning of porcelain/glass insulators may also be an option based on positive experience in India.

Table 3
Creepage Distances of Some HVDC Lines

Scheme	Voltage, kV	Creepage mm/kV	Units /string	Material	Pollution
Pacific intertie, BPA	±500	20.4	24	Porcelain	
Pacific intertie, LADWP	±500	22.6 to 28.2	24 to 30	Porcelain	
Intermountain	±500	29.7 to 39.2	27 to 36	Porcelain	
Itaipu	±600	28.3 to 31.8	32 to 36	Glass	
Rihand - Dadri	±500	41.6	38	Porcelain & Glass	Light
Gezhouba - Shanghai	±500	36	34	Porcelain	Light
Gezhouba - Shanghai	±500	42.3 to 46.6	40 to 44	Porcelain	Moderate
Gezhouba - Shanghai	±500	35		Silicone-Rubber	Moderate
Gezhouba - Shanghai	±500	44		Silicone-Rubber	Heavy

6. Conclusions

This paper has explored some critical issues related to the implementation of 800 kV dc transmission systems:

- Transient and permanent outages of very large power blocks can have a significant impact on the ac systems. Consideration of these factors must occur in the early stages to ensure that features such as overload rating and special controls needed to achieve acceptable levels of performance will be included.
- The factors to be considered in determining the number of valve groups per pole include transportation limitations, impact of loss of the group on the ac systems, acceptability of load shedding, ability to overload the equipment.
- There appears to be little benefit for the utility customer to select transformer valve winding insulation levels and margins that are lower those that have been traditionally applied.
- Currently available mitigative measures for preventing flashovers on outdoor insulation seem to provide satisfactory performance and there is no reason to believe they would not be suitable at 800 kV.

7. References

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For More Information:

Teshmont Consultants LP
1190 Waverley Street
Winnipeg, Manitoba
Canada
R3T 0P4
(204) 284-8100

Email: information@teshmont.com
Web Site: www.teshmont.com